CASE NUMBER:

99-429

HISTORY INDEX FOR CASE: 1999-429
BIG RIVERS ELECTRIC CORPORATION
Integrated Resource Plan

IN THE MATTER OF THE INTEGRATED ROUSOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION

SEQ NBR	ENTRY DATE	REMARKS
M0001	10/19/1999	DAVID SPAINHOWARD BIG RIVERS-EXTENSION TO FILE I.R.P. (FAX)
M0002	10/20/1999	DAVID SPAINHOWARD BIG RIVERS-EXTENSION TO FILE I.R.P.
0001	10/22/1999	Order granting extension of time; info now due 11/22
M0004	11/16/1999	KY NATURAL RESOURCES IRIS SKIDMORE-MOTION FOR LEAVE TO INTERVENE
M0005	11/16/1999	E BLACKFORD AG-MOTION TO INTERVENE
M0003	11/22/1999	BIG RIVERS DAVID SPAINHOWARD-REQUEST FOR EXTENSION OF TIME
0002	11/23/1999	Order granting AG intervention
0003	11/23/1999	Order granting Natural Resources & Environmental Protection Cabt. intervention
M0006	11/24/1999	JAMES MILLER BIG RIVERS-ENTRY OF APPEARANCE
0004	12/10/1999	Order entered; Big Rivers' IRP is now scheduled to be filed by March 22, 2000.
M0007	03/22/2000	DAVID SPAINHOWARD BIG RIVERS-RESPONSE TO ORDER DATED DEC 10,99
0005	04/28/2000	Order setting forth the procedural schedule to be followed in this case.
0006	05/10/2000	Letter granting petition for conf. filed 3/21 by Big Rivers.
M0008	05/18/2000	RONALD MILLS/NREPC-KENTUCKY DIVISION OF ENERGY'S FIRST REQUEST FOR INFORMATION
0007	05/19/2000	PSC Staff's Data Request for info to Big Rivers
M0009	05/23/2000	E BLACKDFORD AG-REQUEST FOR INFORMATION
M0010	05/24/2000	JAMES MILLER BIG RIVERS-RESPONSE TO MOTION OF AG FOR EXTENSION OF TIME
0008	06/05/2000	Order granting AG's request for extension of time; data requests due 5/22
M0011	06/19/2000	JAMES MILLER BIG RIVERS-RESPONSE TO INFO REQ BY PSC STAFF,AG & DIVISION OF ENERGY PLUS CONF
M0012	06/30/2000	JAMES MILLER/BIG RIVERS ELECTRIC-AFFIDAVITS OF PUBLICATION & TEAR SHEETS
M0013	07/13/2000	IRIS SKIDMORE/KY. DIV. OF ENERGY-REQUEST FOR INFORMATION TO THE BIG RIVERS ELEC. CORPORATIO
0009	07/18/2000	Data request, info due 8/18/2000
M0014	07/18/2000	E BLACKFORD AG-SUPPLEMENTAL REQ FOR INFORMATION OF THE AG
M0015	08/18/2000	DAVID SPAINHOWARD/BIG RIVERS-BURNS & MCDONNELL ORGANIZATIONAL CHANGES & RESUME OF WITNESS
M0016	08/18/2000	JAMES M. MILLER/BIG RIVERS-RESPONSES TO 2ND PSC, AG & KY DIVISION OF ENERGY REQUESTS
0010	09/13/2000	Informal Conference Memorandum
M0017	09/22/2000	JIM MILLER/BIG RIVERS-LETTER REGARDING INTEGRATED RESOURSE PLAN
M0018	10/02/2000	GEOFFREY YOUNG/KY NATURAL RESOURCES-COMMENTS RELATED TO THE 1999 INTEGRATED RESOURCE PLAN
M0019	10/02/2000	ELIZABETH E. BLACKFORD ASSISTANT AG-COMMENTS OF THE ATTORNEY GENERAL
M0020	10/27/2000	JAMES MILLER/BIG RIVERS ELECTRIC-REPLY COMMENTS OF BEG RIVERS ELECTRIC CORPORATION
M0022	11/06/2000	IRIS SKIDMORE/KDOE-MOTION FOR AN EXCEPTION TO THE PROCEDURAL SCHEDULE
M0021	11/08/2000	-
M0023	11/09/2000	JAMES MILLER/BIG RIVERS ELECTRIC-OPPOSITION TO MOTION AMENDING SCHEDULE AND MOTION TO STRIK
0011	11/30/2000	Order granting KDOE motion to file additional comments; info due 1/1/2001
M0024	12/18/2000	JAMES MILLER BIG RIVERS-REPLY TO SUPPLEMENTAL COMMENTS OF KY DIVISION OF ENERGY
0013	04/06/2001	Staff Report On the Integrated Resource Plan Report
0012	04/11/2001	Final Order approving integrated resource plan.

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

CERTIFICATE OF SERVICE

RE: Case No. 1999-429
BIG RIVERS ELECTRIC CORPORATION

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed attested copy of the Commission's Order in the above case was served upon the following by U.S. Mail on April 11, 2001.

See attached parties of record.

Stephanie J. Bell
Secretary of the Commission

SB/lc
Enclosure

David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY. 42419 0024

John Stapleton
663 Teton Trail
Frankfort, KY. 40601

Honorable Iris Skidmore
Honorable Ronald P. Mills
Counsel for Natural Resources and
Environmental Protection Cabinet
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY. 40601

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

Honorable James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback &
Miller, P.S.C.
100 St. Ann Building
P.O. Box 727
Owensboro, KY. 42302 0727

Honorable Douglas L. Beresford
Counsel for Big Rivers Electric
Hogan & Hartson L.L.P.
555 Thirteenth St., N.W.
Washington, DC. 20004 1109

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE FILING BY BIG RIVERS ELECTRIC CORPORATION OF ITS 1999 INTEGRATED RESOURCE PLAN	)))	CASE NO. 99-429

ORDER

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

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

IT IS THEREFORE ORDERED that this case is closed.

Done at Frankfort, Kentucky, this 12th day of April, 2001.

By the Commission

ATTEST:

Executive Director

MEMORANDUM

TO: Main Case File -- Case No. 99-429

FROM: William H. Bowker W. H. Bowker
Deputy Executive Director

DATE: April 6, 2001

RE:
1. Load Forecasts – 1999 IRP and Potential Future Inquiries
2. DSM Assessments and Date of Next Big Rivers IRP Filing

The 1999 Integrated Resource Plan of Big Rivers Electric Cooperative, Inc., raises two unusual issues. To ensure that all parties of record are aware of the issues and of the conclusions of Commission staff concerning them, this memorandum is included in the case file and distributed to the parties of record.

1. Load Forecasts – 1999 IRP and Potential Future Inquiries

In its report concerning the 1999 Integrated Resource Plan filing by Big Rivers Electric Cooperative, Inc., PSC staff concludes that it is in general satisfied with the load forecasting presented by BREC in the IRP. PSC staff then offers recommendations concerning load forecasting for BREC to consider in its next IRP filing.

These conclusions and recommendations do not preclude staff's requesting additional forecasts in the time between the present filing and the next scheduled filing. The many changes occurring in the United States electric utility industry and the electricity supply problems being experienced by California at present may require inquiries into the adequacy of generation and transmission to meet Kentucky's needs. Such inquiries may require additional, and perhaps specially tailored, load forecasting by regulated utilities.

2. DSM Assessments and Date of Next Big Rivers IRP Filing

In the PSC staff report there is considerable discussion of Big Rivers' Demand Side Management assessment. The Division of Energy stated its dissatisfaction with Big Rivers' assessment and recommended that the Commission reject Big Rivers IRP and require the utility to submit its next IRP in early 2002, rather than in November, 2002, the date requested by Big Rivers. In its report, Commission staff states that it shares many of the concerns expressed by the Division of

Energy (DOE) relative to Big Rivers' DSM analysis. Staff concludes, however, that 807 KAR 5:058, Section 11 (Procedures for Review of the Integrated Resource Plan) provides no basis for rejecting the Big Rivers 1999 IRP at this late date." Staff recommends that there should be constructive dialogue among DOE, the Attorney General, and Big Rivers well in advance of the next IRP filing. Staff concludes that there is little appreciable difference between the November, 2002 date requested by Big Rivers for its next IRP filing and the early 2002 date recommended by DOE. Staff also concludes that the November, 2002 date will allow better for constructive dialogue among the parties. Therefore, staff concludes that the next IRP filing by Big Rivers will be November, 2002. Finally, staff provides several recommendations concerning the DSM assessment for Big Rivers to consider in the November, 2002 filing.

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BLVD.
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602
www.psc.state.ky.us
(502) 564-3940

MEMORANDUM

TO: Main Case File - Case No. 99-429

FROM: Case No. 99-429 Team

DATE: April 6, 2001

SUBJECT: Commission Staff Report

Attached for filing in this case is the Commission Staff Report on the 1999 Integrated Resource Plan of Big Rivers Electric Corporation. This report, prepared pursuant to 807 KAR 5:058,Section 12(3), summarizes the Staff's review of Big Rivers' 1999 integrated resource plan.

CC: Parties of Record

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602-0615
www.psc.state.ky.us
(502) 564-3940
Fax (502) 564-3460

April 6, 2001

Mr. David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P.O. Box 24
Henderson, KY 42419-0024

Mr. James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback &
Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, KY 42302-0727

Mr. Geoffrey Young
Division of Energy
663 Teton Trail
Frankfort, KY 40601

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

Ms. Iris Skidmore
Mr. Ronald P. Mills
Counsel for Natural Resources
And Environmental Protection
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Mr. Douglas Beresford
Counsel for Big Rivers Electric
Long, Aldridge & Norman
Suite 600
701 Pennsylvania Avenue
Washington, D.C. 20004

RE: Case No. 99-429
Big Rivers Electric Corporation

Dear Madams and Sirs:

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

Sincerely,

Wm H. Parker for

Thomas M. Dorman
Executive Director

Attachment

Kentucky Public Service Commission

Staff Report

On the

Integrated Resource Plan Report

Of Big Rivers Electric Corporation

Case No. 99-429

April 2001

Section 1

INTRODUCTION

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

The Big Rivers Electric Corporation ("Big Rivers") submitted its 1999 IRP to the Commission on March 21, 2000. The report submitted by Big Rivers was prepared by the engineering consulting firm of Burns and McDonnell, and it provided Big Rivers' plan to meet the power requirements of its three distribution cooperatives over the period from 1999 to 2013.

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. Big Rivers provides all of the power requirements of Jackson Purchase Energy Corporation, Kenergy Corporation, and Meade County Rural Electric Cooperative Corporation, with the exception of two aluminum smelters served by Kenergy. The three distribution cooperatives serve primarily residential customers, with 88,790 residential customers in 1999 or 90.0 percent of total customers. Kenergy was formed on July 1, 1999 as a result of the merger of Green River Electric Corporation and Henderson Union Electric Corporation.

Since the filing of its most recent IRP in 1993, Big Rivers has undergone significant changes. Most importantly, Big Rivers no longer operates the generating facilities described in the 1993 IRP, although it still owns them. Big Rivers now purchases a portion of the capacity and energy of these units through an arrangement with LG&E Energy Marketing, Inc. ("LEM"). As a part of this agreement, Big Rivers no longer provides wholesale power service to support Kenergy's retail sales to the two aluminum smelters, Alcan and Southwire. This change significantly reduces the amount of energy sold by Big Rivers, although it still must provide transmission capacity to serve the smelters' electric load.

Because Big Rivers no longer operates generating units, many of the IRP filing requirements concerning power plants are no longer applicable, and Big Rivers' 1999 IRP is significantly different from other IRP filings in Kentucky.

The purpose of this report is to review and evaluate the 1999 IRP in accordance with the requirements of 807 KAR 5:058, Section 12(3), which requires the Commission Staff to issue a report summarizing its review of each IRP filing and offer suggestions and recommendations to be considered in subsequent filings. Staff recognizes that resource planning is an ongoing and dynamic process. Thus, this review has been designed to offer suggestions to Big Rivers on how to improve its plan in the future. Specifically, the Staff's goals are to ensure that:

- All resource options are adequately and fairly evaluated;
- Critical data, assumptions and methodologies for all aspects of the plan are adequately documented and are reasonable; and
- The selected plan represents the least-cost, least-risk plan for the ultimate customers served by Big Rivers and its member systems.

The report also has an incremental component, noting any significant changes from Big Rivers' 1993 filing.

Based on forecasted average annual growth rates of 2.4% per year in system peak demand for generation service and 2.6% in total energy requirements for generation service over the 1998-2013 forecast period, Big Rivers will not become capacity deficient until the year 2008, assuming that 62 megawatts ("MW") of generation is installed in the year 2001 by a Kenergy customer. During the IRP proceeding, Big Rivers was in the process of negotiating a contract to formalize the power supply arrangement that will exist between Big Rivers, Kenergy, and Kenergy's customer after the installation of the generation. Therefore, Big Rivers currently has no plans for the addition of power generation resources or new power supply contracts.

During the summer of 1999, Big Rivers worked with its members and their larger industrial customers to reduce load during times of peak demand. This program successfully reduced load by 17-28 MW, and Big Rivers expanded the use of the program by filing a Voluntary Curtailment Rider which was subsequently approved by the Commission. Big Rivers has also received Commission approval for a temporary rate schedule reflecting market-based rates for new industrial loads or expansions of existing loads of 5 MW or more. This rate schedule will allow Big Rivers to minimize the impact of members' industrial load growth on the results of the 1999 IRP study, and Big Rivers intends to evaluate additional tariff options which would further reduce capacity demand.

The remainder of this report is organized as follows:

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

Section 2

LOAD FORECASTING

Introduction

This section summarizes the methodology and results of Big Rivers' load forecasts, describes changes that have occurred since the last IRP filing, and discusses the reasonableness of the current approach. The load forecast was performed by Burns & McDonnell and provided to Big Rivers in its 1999 Power Requirements Study ("PRS"). The PRS was prepared in accordance with current guidelines of the Rural Utilities Service ("RUS"), and its detailed Work Plan was developed jointly among Big Rivers, its members and Burns and McDonnell, and was approved by Big Rivers' Board of Directors and the RUS's Energy Forecasting Branch. The 1999 PRS mentions the fact that Kenergy Corp. was formed in 1999 from the consolidation of two of the four distribution cooperatives of Big Rivers, although parts of the PRS refer to four (not three) distribution cooperatives.

Methodology

Forecasting future energy and demand is important for the planning and control of Big Rivers, as the forecast serves as a foundation for operations and planning activities. The desired outcome of the forecasting process is a reasonable estimate so that Big Rivers can continue to provide adequate and reliable service at the lowest reasonable cost.

Big Rivers' PRS was based on the long-term and short-term load forecasts for each member cooperative, which were arrived at primarily by using econometric modeling based on historical data from 1979 to 1998. Econometric forecasts developed for the PRS attempted to model the impacts the local economy has had on the cooperatives' historical sales, and use them to project future electricity sales and demand. The basic premise of econometric forecasting is that the historical relationship between energy sales and various influencing factors will continue. Factors such as population, total employment, and weather conditions were evaluated in the models used. The PRS was prepared using a "bottom-up" approach to better analyze the disparate variables that affect the individual customer classes, and then the individual classes were summed to arrive at a total energy requirements forecast for Big Rivers.

The essence of the "bottom-up" approach was the realization that there is no one typical member cooperative. Therefore, the factors that most influence electricity sales for each cooperative needed to be identified in order to develop an aggregate forecast for Big Rivers. Similarly, this approach also recognizes that there is no typical customer class, and therefore sales forecasts for each individual customer class were developed to arrive at the system-wide forecast of each member's total power requirements. Big

Rivers' members' customer classes include the Residential, Small Commercial, Large Commercial, and Public Street and Highway Lighting classes.

Electricity sales in the United States generally track the economy. However, the factors which are most important to a local economy differ from those which drive the overall U.S. economy. Therefore, a detailed analysis of the members' local economies was conducted as part of the PRS. Economic and demographic factors affecting local electricity sales may include electricity prices, alternate fuel prices, the population and employment of the service area, and income levels.

In addition to using econometric modeling, other methods including judgment and discussions with the member cooperatives and Big Rivers were also employed when necessary to enhance the modeling or to replace it where models were impractical. Adjustments were made as necessary to account for known changes to significant loads.

Data for the economic forecasting equations were collected from various sources. Historical system data, including numbers of customers, electricity sales, revenues by customer class, total energy system requirements, and peak demand data were obtained from computerized RUS Form 7 databases. Historical and projected population, employment, and income data for the respective counties were obtained from the Woods & Poole Economics, Inc. database. The county data was weighted by each cooperative's estimate of the percentage of residential customers served by the cooperative as compared to the total number of residential customers in each of the counties in the cooperative's service area. Historical monthly heating and cooling degree day data for the Evansville, Indiana weather station were provided by Big Rivers. Inflation data was obtained from Woods & Poole, as well as the U.S. Department of Commerce. Finally, electricity price projections for each cooperative were developed by applying projected escalation rates to historical average retail electricity prices for Big Rivers.

The long-term peak demand forecast for Big Rivers was developed using an econometric model and the short-term demand model was developed using a seasonal-index model.

Results

The system peak demand for generation service provided by Big Rivers is projected to grow at an average annual rate of 2.4% during the period from 1998 to 2013, while total energy requirements for generation service provided by Big Rivers' are projected to grow at an average annual rate of 2.6% during that period. The system peak demand for transmission service provided by Big Rivers is projected to grow at an average annual rate of 1.7%, and the corresponding energy requirement is projected to grow at an average annual rate of 1.8% from 1998 to 2013. The transmission growth percentages include the electric load of the two aluminum smelters. This level of growth is similar to long-term historical growth rates for Big Rivers.

In comparison to the 1993 IRP, the 1999 load forecast projects substantially increased demand and energy requirements For example, the 1999 load forecast projects total system demand of 1,512,954 kW for the year 2007, while the 1993 load forecast had projected 1,282,000 kW for that year. Similarly, the 1999 load forecast projects total system energy requirements of 10,308,418 MWh for the year 2007, while the 1993 load forecast had projected 8,848,000 MWh for that year. The increase in demand and energy requirements reflects the expansion of paper mills in Big Rivers' service territory and the addition of poultry and processing loads.

From 1998 to 2018, Big Rivers' total system energy requirements are projected to grow approximately 1.5% per year. This forecast is dominated by the non-rural (large commercial) class, which is in turn dominated by the Alcan and Southwire accounts at Kenergy. This class comprised approximately 78% of Big Rivers' members' 1998 sales, and it is expected to maintain fairly constant energy consumption over the forecast period. The two large smelters will continue to receive transmission services, but will no longer receive generation services, from Big Rivers.

Relative to peak demand, Table I-1 of the IRP suggests that Big Rivers' system peak demand will increase from 683 MW in 1999 to 751 MW in 2002, and over the long-term planning period to 2013 it will further increase to 949 MW. System peak demand is defined as the sum of non-rural demand net of smelters plus the rural system demand, and includes losses.

Uncertainty Analysis

Uncertainty analyses were performed to estimate the impact of varying conditions on Big Rivers' rural load growth. Weather assumptions, economic conditions, and electricity prices were varied from the historical norms used in the base case projections The uncertainty analyses were completed based on rural sales, and therefore did not include non-rural sales. The analyses indicated that electricity sales are expected to be much more dependent on future economic conditions than year-to-year weather variation, but also indicated that a high level of year-to-year variation in peak demand is the result of variance in weather conditions.

For Big Rivers, the optimistic and pessimistic forecasts of energy sales range from 4,210,797 MWH to 2,808,213 MWH in 2018. Big Rivers' optimistic and pessimistic forecasts of peak demand range from 966.4 MW to 523.9 MW in 2018.

Discussion of Reasonableness

In its May 1995 Staff Report on Big Rivers' 1993 IRP, Staff made the following recommendations relative to load forecasting for Big Rivers' consideration in preparing its next IRP filing:

- Big Rivers could improve its forecast of electricity requirements by providing justification and additional support for the use of a second methodology to forecast residential and small commercial sales to serve as a benchmark to the primary forecast methodology
- Big Rivers could improve its forecast of electricity requirements by reporting on efforts to incorporate DSM programs into the load forecast.
- Big Rivers could improve its forecast of electricity requirements by providing an intuitive as well as quantitative explanation of forecast results. Big Rivers has moved forward with respect to this recommendation but can continue to improve. Big Rivers should also provide further discussion of why it selects one source of data over another as inputs into its forecasting models.
- Big Rivers could improve its forecast of electricity requirements by continuing to ensure that reasonable forecasts for natural gas are employed into the forecasting process.
- Big Rivers could improve its forecast of electricity requirements by considering uncertainty in its ability to make off-system sales as part of the IRP process.
- Big Rivers could improve its forecast of electricity requirements by reporting on changes to its forecasting methodology due to the DSM strategic study or other load forecast enhancements.

In this IRP, Staff is satisfied that Big Rivers has adequately addressed many of these recommendations, and that the remainder are no longer applicable given significant changes at Big Rivers as well as the passage of time.

Recommendations

In general, Staff is satisfied with Big Rivers' forecasting. However, Staff has the following recommendations for Big Rivers' consideration in its next IRP filing:

- Provide a comparison of forecasted winter and summer peak demands with actual results for the period following Big Rivers' 1999 IRP, along with a discussion of the reasons for the differences between forecasted and actual peak demands.
- Provide a comparison of the annual forecast of energy sales with actual results for the period following the 1999 IRP. Include a discussion of the reasons for the differences between forecasted and actual results.
- Big Rivers should, to the extent possible, report on and reflect in its forecasts the impacts of increasing wholesale and retail competition in the electric industry.
- Big Rivers should attempt, either in its forecasts or in its uncertainty analysis, to incorporate the impacts of environmental costs such as those associated with NOx reductions imposed on sources in the Eastern United States.

Section 3

DEMAND SIDE MANAGEMENT

Introduction

This section summarizes the DSM assessment included in Big Rivers' 1999 IRP. According to the IRP, Big Rivers is particularly sensitive to financial pressure given its recent bankruptcy and restructuring, and therefore significant care should be taken to ensure that Big Rivers' financial standing is supported and not negatively impacted by the resource mix for both supply and demand-side options. More specifically, Big Rivers believes that its surplus capacity situation means that it should only implement DSM programs that bolster its current capacity situation, increase its cash flow, and mitigate rate pressures on the cooperative and its members' customers. Furthermore, Big Rivers also believes that any program implemented must provide verifiable, cost-effective capacity reduction or load shifting if it is to benefit Big Rivers.

Screening Process and Results

Big Rivers' 1999 IRP states that its initial analysis of all DSM options indicated that Big Rivers will benefit most from programs that increase load factor and revenues, while reducing coincident peak capacity needs. Such programs would allow Big Rivers to capitalize on future capacity sales while bolstering its financial status. Therefore, Big Rivers concluded that load shifting programs such as load management would have the most beneficial impact (in terms of a positive rate effect and total resource impact) by increasing off-peak sales and reducing peak demand.

According to Big Rivers, a 1995 DSM study undertaken by Big Rivers and prepared by R.W. Beck considered and analyzed several hundred DSM options for future implementation. Of those options, a limited subset of residential and commercial programs passed the cost-effectiveness criteria of the Total Resource Cost (TRC) and Ratepayer Impact Measure (RIM) Tests. The TRC test is a measure of a program's benefits versus costs for all ratepayers, while the RIM test is a measure of rate impacts for a utility. The programs considered for implementation were studied individually and then grouped into plans, which were then studied for TRC and RIM evaluation. Two TRC programs and four RIM programs were found to be cost effective; the TRC programs were residential space conditioning efficiency and residential water heater efficiency, while the RIM programs were residential water heater replacement and air source heat pump with two identical programs on the commercial side.

Big Rivers noted that its marginal costs have fallen since the time of the 1995 study, while the efficiency of DSM technologies has increased due to technical and market transformation. According to Big Rivers, given the trend toward deregulation and competition, most options considered in the original study have become less cost-effective, and potential benefits have been substantially reduced and may even be negligible. In particular, the IRP suggests that the 1995 study may not have considered the impacts of free riders and free drivers, and that more recent analysis of these programs by Burns & McDonnell indicates that Big Rivers must expend considerable capital to implement them, while benefiting only marginally if at all. Therefore, Big Rivers stated that the financial risks of these expenditures far outweigh the potential benefits given the utility's current financial standing.

The IRP also states that the 1995 study recommended options to promote electric load growth by switching from natural gas, such as ground source heat pumps and water heaters. Big Rivers did not believe these options to be beneficial in view of the financial resource requirements.

However, Big Rivers' 1999 IRP strongly promoted a "focused, low-cost load management program" using such tools as innovative rate structures and interruptible rate schedules for large commercial and industrial customers. These alternatives rely upon voluntary curtailments of members' customers and Big Rivers projects they could provide up to 80 MW of coincident reduction when fully implemented from 2005 through 2013. An example of such a program is Rate Schedule 10, the recently-approved tariff allowing for market-based rates for new or expanded loads of industrial customers. On the residential side, the IRP suggests possible programs such as water heater timers and water heater wraps, but recommends that such residential programs be limited to 5 MW in total over the study period, if implemented at all.

In summary, Big Rivers' 1999 IRP recommended that it continue to implement a combined commercial/industrial load management plan especially targeted to industrial customers with large coincident demand, but that it limit residential DSM programs if they are to be implemented at all.

Comments of the Attorney General

The Office of the Attorney General (AG) provided several comments relative to Big Rivers' DSM efforts. First, it endorsed Big Rivers' customer-based approach of developing interruptible load programs and distributed generation (rather than relying upon the future addition of gas-fired capacity), although it described the proposed implementation of those programs as problematic. Specifically, it viewed as innovative Big Rivers' implementation of Rate Schedule 10, and it characterized the use of interruptible tariffs as valuable in avoiding the need to build or procure expensive new generating capacity. However, the AG argued that Big Rivers' customer-based approaches to meeting new loads are oriented toward large customers, and that smaller customers (which constitute the majority of the members' ultimate customers) can and should be included in distributed generation and strategic conservation programs. The AG pointed out that the R.W. Beck study rejecting strategic conservation was done at a time when Big Rivers had a surplus of generating capacity and no need to reduce load. According to the AG, now that Big Rivers must control load growth or deal with load growth issues, it should immediately set about securing a new study to determine which conservation and load management programs are cost effective.

The AG also commented that small distributed generation is discouraged by extensive regulations and the cost of special metering from the PURPA era. The AG pointed out that more than half of the states in the nation have some form of Net Metering to remove this barrier, and it encouraged Big Rivers to develop Net Metering tariffs that are beneficial to both Big Rivers and the smaller cooperative members so that all customers will have the opportunity to participate in distributed generation programs. In response, Big Rivers agreed to consider Net Metering prior to filing its next IRP, while stating that it is willing to design Net Metering tariffs that are beneficial to Big Rivers and its members.

Comments of the Kentucky DOE

The Kentucky Division of Energy (DOE) took strong exception to Big Rivers' DSM analysis, calling for the Commission to reject the 1999 IRP because it "rules out the serious consideration of a very large class of DSM programs," and, therefore, it "fails to meet future demand at the lowest possible cost for all customers within the utility's service area, as required by (the Commission's IRP Regulation) 807 KAR 5:058." In the alternative, the DOE suggested that the Commission require Big Rivers to submit its next scheduled IRP in approximately twelve months and require that it conform to the provisions of 807 KAR 5:058. In its extensive critique of Big Rivers' DSM analysis, DOE characterized the 1995 study by R.W. Beck as "fundamentally flawed," and "outdated" with regard to the list of DSM technologies considered.

DOE's first point of emphasis in challenging Big Rivers' DSM analysis was that, in the opinion of DOE, the TRC test most closely mirrors the intent of 807 KAR 5:058, and should be the primary criterion showing whether all ratepayers are being optimally served by DSM programs. In arguing this point, DOE states that a strategy that minimizes rates will differ in significant respects from a strategy that minimizes the total costs for all customers. As Big Rivers correctly noted in its Reply to DOE's Supplemental Comments, Staff has previously addressed DOE's arguments on these points in the recent Staff Report on the IRP of Louisville Gas & Electric Company and Kentucky Utilities Company (Case No. 99-430; Staff Report issued September 2000). In that report, Staff stated the following:

> "... Staff disagrees with DOE's expansive view of the applicability of the TRC test as well as its contention that minimization of PVRR should not be the primary consideration in the development of a utility's IRP ... Minimizing PVRR has been accepted as the primary criterion for IRPs since the promulgation of 807 KAR 5:058, the regulation which requires the filing of IRPs by Kentucky's major electric utilities. Minimizing utility revenue requirements which would be borne by the utility's customers is entirely consistent with the language of KAR 5:058, which says that utility resource plans are to "meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers ..."

Big Rivers also points out that KRS 278.285 (3) requires that the cost of DSM programs may only be assigned to the class or classes of customers who benefit from the programs, not from all customers. Therefore, Staff affirms its previous conclusion that minimization of PVRR, and not the TRC test, should be the primary consideration in an IRP's development. For this reason, Staff does not believe that DOE's TRC-Test arguments are an adequate basis to reject Big Rivers' 1999 IRP for failing to meet the provisions of 807 KAR 5:058.

DOE continued its critique of Big Rivers' DSM analysis by discussing the cost-effectiveness results for 11 specific DSM programs analyzed in detail in the 1995 R.W. Beck study. That study evaluated the cost-effectiveness of the 11 programs based upon the four standard (California) tests – the Participant Test, the Utility Cost Test, the Ratepayer Impact Measure Test, and the TRC Test. DOE points out that the results of these cost-effectiveness tests, as well as the program selection criteria endorsed by Burns & McDonnell in answers to data requests, are in "striking contradiction" to the consultants' actions in developing the 1999 IRP. DOE suggested that Burns & McDonnell may have discarded a very large class of DSM programs on the grounds that they may exert an upward pressure on rates, resulting in elimination of several potential DSM programs that would lower both the revenue requirement of the utility (based on the Utility Cost Test) and the total costs of the average customer (based on the TRC Test).

In response, Big Rivers disagreed with DOE's criticisms of the 1995 study, noting that it analyzed several DSM programs in the context of Big Rivers' supply situation at the time. It further noted that Big Rivers has experienced dramatic changes since its last IRP, but that the basic concepts used to screen DSM programs are still valid because Big Rivers still has a low cost of marginal energy and can meet all but a small portion of its supply needs in 2008-2010 with its existing resources. However, while calling the 1995 R.W. Beck study adequate for purposes of the 1999 IRP, Big Rivers conceded that its emergence from bankruptcy with a dramatically reduced staff and an emphasis on cost reductions made performing a new study for this IRP problematic. Furthermore, Big Rivers stated that it recognizes the role of DSM in integrated resource planning, and that it fully intends to perform a new DSM analysis in connection with its next IRP, which it has requested be due three years from the due date of the 1999 IRP (November 2002).

While Staff shares many of the concerns expressed by DOE relative to Big Rivers' DSM analysis (and especially its reliance upon 1995 study results), a review of 807 KAR 5:058, Section 11 ("Procedures for Review of the Integrated Resource Plan") shows that it provides no basis for rejecting Big Rivers 1999 IRP at this late date. Subsection (3) of that section states that "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." Subsection (4) of that section goes on to state that "A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing." Nevertheless, Staff expects that Big Rivers' next IRP filing will provide a rigorous, updated, and thoroughly documented assessment of all reasonable DSM alternatives as required by 807 KAR 5:058.

In addition, Big Rivers has suggested that a "constructive dialogue among DOE, the Attorney General and Big Rivers in advance of the original filing date for the Big Rivers IRP in April of 1998, would have been far more useful to the process than the DOE's after-the-fact, adversarial approach to this IRP proceeding." Staff believes that a dialogue of the type suggested by Big Rivers has considerable merit in advance of Big Rivers' next IRP filing. Therefore, Staff recommends that Big Rivers, DOE, and the AG meet well in advance of the next IRP filing to discuss the parties' concerns. In addition, Staff recommends that Big Rivers should discuss in the next IRP filing the results of its discussion with the parties, and how it has incorporated the parties' concerns into the 2002 DSM analysis.

Relative to the timeframe for filing its next IRP, Big Rivers has requested that it be due in November 2002. At this point, DOE's alternative request that Big Rivers should be ordered to file its next IRP within 12 months (or early 2002) does not differ appreciably from Big Rivers' request. Moreover, the additional months will allow the parties sufficient time to engage in a constructive dialogue to improve the next IRP filing. Therefore, Staff believes that good cause exists to allow for a November 2002 filing date for Big Rivers' next IRP.

Another point of contention between Big Rivers and DOE was related to the possibility of implementing strategic conservation programs which would allow Big Rivers to sell surplus energy off-system at a profit. Staff agrees with Big Rivers that the IRP process as defined by 807 KAR 5:058 focuses on meeting future demand within Big Rivers' service area, as opposed to an expansive view which includes wholesale sales off-system.

DOE also suggested in its comments that Big Rivers' IRP was deficient because it does not assess potentially cost-effective improvements to and more efficient utilization of transmission and distribution facilities. More specifically, DOE took issue with Big Rivers' exclusion of its three member distribution cooperatives from the IRP analysis, and it requested that the Commission clarify the intent of 807 KAR 5:058, Section 8(2)(a) and require the member cooperatives of Big Rivers (and East Kentucky Power Cooperative) to cooperate with the latter's transmission and distribution planning activities in future IRPs in order to minimize total system costs. In response, Big Rivers noted that the IRP regulation does not require Big Rivers to include member distribution cooperative distribution planning in its IRP, and that Big Rivers lacks the legal authority to do so. Staff agrees with Big Rivers on this point. Relative to potential improvements to and more efficient utilization of Big Rivers' transmission system, Staff recommends that Big Rivers provide greater analysis and narrative discussion of this issue in its next IRP.

In comments of a more generic nature, DOE recommended that Big Rivers initiate a comprehensive market transformation program in the new commercial construction sector; that Big Rivers use local integrated resource planning ("LIRP") to potentially defer transmission and distribution upgrades; that Big Rivers should promote cogeneration and other distributed generation; that Big Rivers should support statewide and regional market transformation initiatives, defined as "planned interventions in the market that lead to longer-lasting impacts than traditional utility-sponsored DSM programs that depend on ongoing rebates for their effectiveness"; and that Big Rivers should launch a Kentucky design initiative to improve the quality of energy system design and engineering. Big Rivers responded that most of these suggestions were outside the scope of an IRP proceeding and more appropriate for the Kentucky legislature to address. However, Big Rivers did commit to considering LIRP prior to its next IRP and in its interim planning of transmission system improvements, although it also acknowledged the difficulties faced by a G&T cooperative in implementing the concept.

Discussion of Reasonableness

Staff fully appreciates the extraordinary circumstances which have surrounded Big Rivers since the filing of its previous IRP. Staff also supports Big Rivers' recent progress with regard to innovative rate schedules, load management, and distributed generation. However, with regards to Big Rivers' contention that most DSM options considered in the 1995 study are less relevant because of the trend toward deregulation and competition, Staff has noted in other IRP Staff Reports (such as the East Kentucky Power IRP Staff Report of April 2000) that the specter of competition should not preclude careful examination of demand side resources. In addition, the events in recent months, especially price spikes and rolling blackouts in certain power markets in the Western United States, appear to have slowed or halted the deregulation movement, at least temporarily. Therefore, Staff believes that future IRPs of Big Rivers and other Kentucky generators should continue to thoroughly assess all reasonable options, including DSM options, for meeting forecasted electricity requirements at the lowest possible cost, consistent with the IRP Regulation. Moreover, Staff also expects DSM analyses submitted in IRP filings to be well-documented and based upon the most current information possible, which is especially important in view of the continued uncertainties in local and national electricity markets. Finally, it should be noted that discussion of DSM during this process was somewhat hampered because of the age of the study relied upon by Big Rivers, as well as staff turnover experienced by Big Rivers' consultant. In future IRPs, Staff expects that Big Rivers will take steps to prevent this situation from recurring.

Summary of Recommendations

Relative to the DSM efforts of Big Rivers as reflected in the 1999 IRP, Staff makes the following recommendations:

- In its next IRP filing due in November 2002, Big Rivers should discuss its progress in implementing Net Metering tariffs that are beneficial to both itself and its members.

- Big Rivers should meet with the DOE and the AG well in advance of the next IRP filing to establish a constructive dialogue relative to DSM and other concerns raised by the parties. In addition, Big Rivers should discuss the results of this dialogue and how it has incorporated the parties' concerns into the 2002 IRP analysis.
- Big Rivers should provide a more extensive discussion of potential improvements to and more efficient utilization of its transmission system in its next IRP filing.
- In its next IRP filing, Big Rivers should report on efforts to evaluate and support Local Integrated Resource Planning, cogeneration and distributed generation, and other initiatives of the type advocated by DOE and the AG.
- Big Rivers should perform a new DSM study prior to its next IRP filing and consider expanding its load management programs to include residential and small commercial customers, with a particular emphasis on air conditioning cycling programs.

Section 4

SUPPLY-SIDE RESOURCE ASSESSMENT

Introduction

This section summarizes and reviews Big Rivers' evaluation of supply-side resources. Because Big Rivers no longer operates generating units, many of the IRP filing requirements are no longer applicable and will not be discussed herein.

Existing Power Supply

Big Rivers' existing power supply consists largely of firm contracts for power purchases from LEM and the Southeastern Power Administration ("SEPA"). Table I-1 of the IRP shows that the maximum capacity from the LEM contract is 572 MW for the year 2000, while the maximum capacity from the SEPA contract is 178 MW for that same year (and also for each year through 2013). With forecasted peak demand of 717 MW in 2000, this leaves Big Rivers with a projected capacity surplus of 33 MW. The LEM contractual obligation increases to a maximum capacity of 597 MW starting in the year 2001. The contract includes liquidated damages for non-delivery, and therefore Big Rivers has no need for a reserve margin as is the case with generating utilities. Big Rivers also has access to the wholesale power markets to buy and sell power as needed subject to market availability.

With Big Rivers' projected load growth, the LEM and SEPA contracts will provide capacity in excess of projected demand until the year 2004. However, Big Rivers expects 62 MW of generation to be installed by a customer of Kenergy in the spring of 2001, and is in the process of negotiating a contract to formalize the power supply arrangement that will exist between the three parties after the installation of that generation. This generation addition would effectively reduce Big Rivers' power supply obligations by 62 MW. With such capacity available, Big Rivers would not become capacity deficient until the year 2008 with the projected load growth. Therefore, Big Rivers currently has no formal plans for the addition of power generation resources or new power supply contracts. However, if the Kenergy customer's generation is not installed, Big Rivers will need to immediately begin the decision-making process on the acquisition of its next resource to meet peak demand in the years 2004-2011.

The LEM contract has a 25-year term and will be in effect through 2023. This contract specifies the minimum and maximum hourly and annual capacity and energy amounts at substantially fixed rates. As mentioned previously, the maximum capacity available pursuant to this contract will increase from 572 MW to 597 MW beginning in the year 2001, with further increases to 717 MW in 2011 and to 800 MW in 2012. It should also be noted that Big Rivers has been obligated to provide wholesale power to other entities (including Hoosier Energy, Oglethorpe Power and Henderson Municipal Power & Light), and all of these power requirements must be purchased from LEM.

These wholesale contracts will expire in the next three years, and none of the associated capacity and energy requirements are included in this IRP study as they were in the 1993 IRP.

The SEPA contract allows Big Rivers to take fixed capacity and energy allocations based on a monthly schedule. The contract runs through June 2017. The SEPA contract limits the monthly energy taken by Big Rivers to 42,720 MWh and imposes a minimum energy take of 10,680 MWh per month. The monthly limitation could potentially expose Big Rivers to energy purchases from the spot market or other short-term sources of power during the summer peak months.

Supply-Side Evaluation

As a first step in the supply-side evaluation, Burns & McDonnell reviewed power supply alternatives within two basic categories: owner-constructed and purchases. Relative to owner-constructed alternatives, the addition of a coal-burning unit was not considered in the screening analysis because of the limited capacity requirements of Big Rivers over the study period. The options that were considered within this category were simple-cycle combustion turbines ("CTs"), combined-cycle CTs, reciprocating engine units, fuel cells, and renewable resources such as wind and biomass. The fixed and variable costs of the first three alternatives were developed to provide the lowest cost options available. Costs were obtained from manufacturers, similar operations of other utilities, and the Distributed Generation Guidebook written by Burns & McDonnell in 1998 and published by the Gas Research Institute. For fuel cells, which may achieve commercial availability in the near future, the estimated costs were based on information provided by fuel cell manufacturers. For the renewable resources, wind turbine costs were obtained from an 80 kW installation in Iowa, while biomass costs were based on reports from the Oak Ridge National Laboratory.

Fuel costs for the owner-constructed options were estimated assuming that natural gas would be utilized in any generating additions. Cost estimates for other fuels such as coal or fuel oil were not developed for the IRP because they were not anticipated to be used. The IRP acknowledges that estimating natural gas prices is always a challenge, but for purposes of the study, natural gas prices were estimated to increase at a rate of approximately 1.5%. (It should be noted that significantly higher natural gas prices were being experienced, and forecasted, in late 2000 and early 2001 as this report was being written.)

Relative to power purchases, utilities can purchase capacity and energy in firm and non-firm contracts or purchase shares in generation facilities. Both options depend on the availability of surplus capacity in the area. However, the East Central Area Reliability Council (ECAR) region is beginning to face tight capacity, with margins of about 8% for the early 2000 time frame unless generation is constructed. With forced outage rates of potentially greater than 5%, the region is exposed to dependence on imports.

For contract purchases, recent solicitations by Burns & McDonnell indicated a lack of response for these types of offers. However, peaking power may be available in the 2004-2010 time frame. Recent peaking power supply offers (from power marketers) evaluated by Burns & McDonnell for the years 2002-2004 had capacity charges in the $4-$5/kW-month range and energy charges of approximately $100/MWh.

For unit purchases, there did not appear to be any surplus capacity available from coal units in the area. Because of this perceived lack of realistic options, no unit purchases from coal facilities were modeled. However, there were announcements of intentions to build gas-fired simple and combined cycle units within the region (i.e., Kentucky and Indiana) at the time of preparation of the IRP, with at least three of those units scheduled for operation in the summer of 2000. It was therefore determined to develop low-cost options germane for Big Rivers from projects considered feasible for projected needs, and those costs would then establish offers to the promoters of the larger area projects and represent the maximum that Big Rivers could pay for someone else to provide the capacity and energy.

Also included in Big Rivers' power supply screening report was discussion of Voluntary Industrial Curtailment. During the summer of 1999, Big Rivers worked with its members and their large industrial customers to reduce load during times of peak demand. This program was mutually beneficial for Big Rivers, the member cooperatives, and their retail customers through the sharing of cost savings. Load reduction ranged from a low of 17 MW to a high of 28 MW and the voluntary curtailment involved four industrial customers. Big Rivers expects to expand the use of the program, and filed a Voluntary Curtailment Rider with the PSC, which was subsequently approved.

Screening Results

Several sizes of each technology were selected to compare the operating costs at various capacity factors to screen the more applicable units for further review. The energy requirements from new capacity reviewed for Big Rivers are expected to be in the peaking and intermediate range based on the analysis of Big Rivers' load profile and LEM contract. The capacity factors for these types of resources are traditionally below 40-45%. The relative levelized total costs of the options over a range of capacity factors were included in the analysis, and the screening cost curves allowed for a comparison of units over a range of operating levels. The fixed and variable costs of each option were projected for 20 years of operation and levelized for a comparison of the economics of each unit.

Based on the projected loads and resources available to Big Rivers and the relative capacities and costs of the options reviewed, Burns & McDonnell selected five power supply options to move into more detailed analysis. These options were a 45 MW simple-cycle CT, a 53 MW combined-cycle CT, combined-cycle unit purchases, peaking power purchases, and a voluntary Commercial/Industrial load management program.

Discussion of Reasonableness

The 1995 Staff Report included three recommendations relative to Big Rivers' supply side resource assessment. These recommendations were as follows:

- Big Rivers should continue to study the off-system power market utilizing the advice of expert consultants as appropriate and incorporate lessons from failed competitive bids.
- Big Rivers should consider uncertainty in the level of off-system sales in its planning process.
- Big Rivers should continue to study transmission upgrades that will improve its ability to make off-system sales and report back on these studies in subsequent plans.

These recommendations were based upon Big Rivers' capacity situation at the time of the 1995 report, and Staff is satisfied that Big Rivers has adequately addressed them given their more limited applicability to present circumstances. Specifically, Big Rivers has noted that off-system sales are no longer needed to allow Big Rivers to generate its revenue requirements, but also that it is very active in the short-term market and is exposed daily to market intelligence and pricing information.

Relative to the 1999 IRP analysis of supply-side resource options, Staff recommends that Big Rivers address certain criticisms by the AG and report the results in its next IRP filing. Specifically, the AG stated that Big Rivers' 1999 did a poor job of examining renewable resource options which may be critical in meeting environmental requirements in the future. The AG suggested that Big Rivers is adjacent to a number of potential hydropower sites on the Ohio River that could supply low-cost (and clean) power. The AG also suggested that Big Rivers' analysis of biomass was an expensive theoretical plan involving growing trees on large plantations, and that a lower cost biomass option using massive amounts of nearby woodwaste should have been analyzed. Staff recommends that Big Rivers should explore these options and report the results in the next IRP filing.

Summary of Recommendations

- Big Rivers should explore the renewable resource options of hydropower and biomass as suggested by the AG, and report the results in its next IRP filing.
- Big Rivers should include a thorough analysis of purchase power options that considers non-utility generation being developed in Kentucky and Indiana in its next IRP filing.

Section 5

INTEGRATION AND PLAN OPTIMIZATION

Introduction

The final step in the IRP process is the integration of supply-side and demand-side options to arrive at the optimal integrated resource plan. This section will discuss Big Rivers' integration of supply-side and demand-side options and the resulting plan.

The Integration Process

Big Rivers' IRP discussed the production cost modeling that was done by its consultant, Burns & McDonnell, to simulate the dispatch of Big Rivers' power supply resources for the years 1999-2013. The model dispatched the available resources on an hourly basis taking into account both hourly, monthly and annual contract maximums and minimums and the contract prices and spot market price estimates. The output of the model contained the energy dispatch and costs associated with meeting the hourly requirements of Big Rivers. The model also used the daily electricity spot market prices for the last 12 months to determine the potential for non-member sales and revenues in the future. Because of the firm nature of Big Rivers' purchases and its lack of generating capacity, the model did not include the forced outage rates, heat rates, fuel, and O&M costs that are utilized by typical production cost models. Both existing and potential future resources were input to the model to determine the most cost-effective method of meeting future power supply needs, and the cases were evaluated with and without the sales of surplus power.

Based on the results of the screening analysis described elsewhere in this report, five power supply options were considered in the production cost modeling. These options included generation, purchases, and DSM options. All cases were designed to meet the demand requirements of Big Rivers and were modeled with and without the projected non-member sales of surplus capacity and energy.

The results of the production cost modeling were that the generation options and purchase of combined cycle unit capacity and energy are not cost effective in meeting Big Rivers' native load when compared to the load reduction, spot market purchase, and peaking purchase options. When non-member sales of surplus capacity and energy are considered, the combined cycle option is the most favorable. Three of the options were evaluated with capacity being added in both the year 2002 to take advantage of potential spot market sales and in the year 2009 to meet some of Big Rivers' capacity requirements.

Big Rivers stressed that the installation of 62 MW of generation by Kenergy's customer has a significant impact on the results of its analysis. If the unit is not installed as expected, the Big Rivers system is projected to become capacity deficient in 2004, with the capacity deficiency projected to peak at 118 MW in 2010 before increases in the capacity of the LEM contract take effect in 2011 and 2012 to eliminate the deficiency. If that occurs, Big Rivers must begin planning immediately for its next capacity resource. From the results of its risk assessment, Big Rivers suggested that after the commercial/industrial load management program, CTs and peaking power purchases reflect the most economical method to meet the capacity deficiency and minimize the potential financial risks associated with spot market purchases. This evaluation was based on the annual revenue requirements and 15-year net present values of total revenue requirements included in Big Rivers' IRP.

The IRP also recommended that Big Rivers continue its evaluation of the combined commercial/industrial load management plan; that it should encourage the use of distributed generation among its members to lower peak demands and energy requirements and provide greater flexibility in power supply operations; that it maintain an ongoing dialogue with other power suppliers within the next three years regarding low cost energy and capacity sources; and that it continue to monitor the progress of state and federal legislation to determine potential impacts upon the Big Rivers system. Big Rivers should discuss these efforts in significant detail in its next IRP filing.

Discussion of Reasonableness

The 1995 Staff Report included five recommendations relative to Big Rivers' acid rain compliance planning. However, these recommendations are no longer applicable because of the agreements that have occurred between Big Rivers and LG&E subsequent to that report.

As this Staff report was being written, Staff was unaware of whether or not Big Rivers had reached a contractual agreement with the affected parties relative to the installation of the 62-MW distributed generation project. The IRP had projected that this project would be operational in the spring of 2001. Because of the importance of this issue to Big Rivers' capacity planning situation, Staff recommends that Big Rivers update the Commission on the status of the project, starting one month from the issuance of this report and continuing on a quarterly basis until the project is operational or until Big Rivers has decided upon an alternative solution.

Summary of Recommendations

- Big Rivers should update the Commission on the status of the 62-MW distributed generation project on a quarterly basis, and provide copies of that update to the parties in this case. Such updates should begin one month from the issuance of this report, and continue until the project is operational or until Big Rivers has decided upon an alternative solution.

- Big Rivers should discuss, in significant detail in its next IRP filing, its efforts relative to the 1999 IRP's recommendations to continue evaluation of the combined commercial/industrial load management plan; to encourage the use of distributed generation among its members to lower peak demands and energy requirements and provide greater flexibility in power supply operations; to maintain an ongoing dialogue with other power suppliers regarding low cost energy and capacity sources; and to monitor the progress of state and federal legislation to determine its potential impacts upon the Big Rivers system.

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

Ronald M. Sullivan
Jesse T. Mountjoy
Frank Stainback
James M. Miller
Michael A. Fiorella
William R. Dexter
Allen W. Holbrook
R. Michael Sullivan
P. Marcum Willis
Anne H. Shelburne
Bryan R. Reynolds
Mark G. Luckett

December 15, 2000

RECEIVED
DEC 18 2000
PUBLIC SERVICE COMMISSION

Thomas M. Dorman
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: The Integrated Resource Plan of Big Rivers Electric Corporation, PSC Case No. 99-429

Dear Mr. Dorman:

Enclosed are an original and ten copies of the Reply of Big Rivers Electric Corporation to Supplemental Comments of the Kentucky Division of Energy in this matter. I certify that a copy of this letter has been served on the parties of record by mailing a copy of same to them, on this date, postage prepaid.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej

cc: Service List
David Spainhoward

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

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

SERVICE LIST
PUBLIC SERVICE COMMISSION CASE NO. 99-429

Elizabeth Blackford, Esq.
Assistant Attorney General
Utility and Rate Intervention Division
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601

Office of the Attorney General of the Commonwealth of Kentucky

Iris Skidmore
Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601

John Davies
Director of Division of Energy NREPC
663 Teton Trail
Frankfort, KY 40601

Counsel for Natural Resources and Environmental Protection

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
DEC 1 8 2000
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION) **CASE NO. 99-429**

REPLY OF BIG RIVERS ELECTRIC CORPORATION TO SUPPLEMENTAL COMMENTS OF THE KENTUCKY DIVISION OF ENERGY

Big Rivers Electric Corporation ("Big Rivers") makes this reply to the Kentucky Division of Energy ("KDOE") Supplemental Comments ("Supplemental Comments") filed pursuant to order of the Public Service Commission ("Commission") dated November 30, 2000.

Summary of Big Rivers' Position

The Big Rivers 1999 integrated resource plan ("IRP") satisfies the requirements of 807 K.A.R. 5:058 by showing that Big Rivers can meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers. This subject was discussed in detail in the Reply of Big Rivers to Intervenor Comments dated October 26, 2000 ("Big Rivers Reply Comments").

The position of KDOE that has persisted into the KDOE Supplemental Comments is that Big Rivers is not meeting future resource requirements at the lowest possible cost because it is not relying upon demand side management ("DSM"), including strategic conservation measures, as sources of electricity to meet those needs. KDOE relies upon distortions of the Big Rivers IRP and sweeping generalizations to reach its penultimate conclusion that Big Rivers' IRP should be rejected. Yet KDOE has been unable to provide a single example of how any DSM or strategic conservation concept, when applied to the specific facts and circumstances of the Big Rivers situation, would provide a lower cost, dependable supply of power for the retail customers of Big Rivers' members.

As Big Rivers understands the IRP regulation, demand side management and conservation are not goals, they are suggested as available means to the end of meeting future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers[1]. While a utility is required to consider DSM in its planning, it is not required to use DSM (including conservation) to meet its resource requirements if it can meet those requirements more reliably, at a lower cost, from another source or sources.

Big Rivers has no capacity deficiencies during the study period. Even if the cogeneration source anticipated in the IRP does not materialize, capacity deficiencies do not begin until 2004, are measured in hours at discreet peak periods, and are resolved using the existing commercial/industrial load management program (a DSM program), combustion turbines and peaking power purchases. IRP at VII-2, paragraph 3. Big Rivers will be performing an update to its DSM analysis in connection with its next IRP, and will consider the role of DSM (including strategic conservation) as a source for the power supply Big Rivers will need during that planning period to meet future demand.

---

[1] Development and implementation of programs to conserve energy and to develop alternate energy sources are the statutory duties of KDOE, not the Commission. KRS 224.10-100(28).

Big Rivers' Initial Comments at 10.

Reply of Big Rivers to Specific Arguments of KDOE

The specific assertions of KDOE in its Supplemental Comments are misplaced or misleading. The numbered paragraphs below contain Big Rivers' responses to the corresponding numbered paragraphs in the KDOE Supplemental Comments.

1. **Big Rivers' IRP evaluates resource options on the basis of the PVRR and TRC tests, not on the basis of rate impact.**

The evaluation of resource options in Section 5 of the Big Rivers IRP is based upon the PVRR and TRC tests. Contrary to the assertions of KDOE, the rate impacts of the studied resource options are not mentioned in that analysis.

KDOE is the party that is confused about the relationship between costs and rates. Rates are a derivative of utility costs. Reducing utility costs controls rates, the stated purpose of the IRP process. An electric cooperative operates on a nonprofit basis, so utility costs basically equal rates at a cooperative, regardless of customer costs. KDOE offers no support for its theory that use of the word "costs" in the IRP regulation refers to the retail customer's cost of electricity, adjusted for the effects of DSM at the customer's electric consuming facility.

The KDOE example of the effect a DSM program could theoretically have on customer costs and utility revenue requirements is wholly immaterial to the consideration by the Public Service Commission staff ("Staff") of the Big Rivers IRP. In the hypothetical example described by the KDOE, the consumer is able to reduce its expenditures for electrical energy by 27.9% through an investment in an unidentified

DSM methodology. Similar DSM programs may have produced that result in New York State in 1989[2], but KDOE has not shown that they have the same value for Big Rivers, on the Big Rivers system, during the study period.

The KDOE example does, however, make an interesting point about the effect of avoided cost levels on tests used in evaluating DSM options. The retail consumer always has the option of investing in energy reducing devices and recovering the savings directly from its bill. In evaluating the benefit of the program, the retail customer can use an avoided cost of the retail rate in its evaluation (the Participant Test), while Big Rivers and the wholesale member-customer can use only the Big Rivers avoided cost employed in the IRP analysis (Total Resource Cost Test). If the cost of the DSM program is the same regardless of the type of test considered, the benefit cost ratio for the Participant Test will be approximately three times the benefit under the Total Resource Cost Test.

KDOE contends that the TRC test is the only valid test to evaluate DSM options. KDOE Initial Comments at 2. Without further arguing the correctness of that position, and assuming that consumers are always interested in saving money, retail consumers should be taking advantage of every energy reducing device available because their savings are three times greater than the savings of Big Rivers. If they are not so motivated, and require a higher benefit cost ratio to participate, then Big Rivers assumes that some incentive would have to be provided to entice them to participate. Any enticement increases the costs of the DSM program, since the device generally costs the

[2] KDOE Supplemental Comments at 5-6, and footnote 5.

same to either the consumer or the utility. Because avoided costs are the same, the benefit/cost ratio goes down as the costs to encourage participation in the DSM program increase. If the program was not of sufficient merit for the customer with a retail avoided cost benefit substantially greater than the benefit from the combined customer/utility perspective, Big Rivers submits that it is not valid to assume it will be of benefit with additional subsidization by Big Rivers, which must be considered in the TRC test. To the degree Big Rivers invests in programs that are not of sufficient interest to the consumers, it drives up the costs to Big Rivers. These costs have to be recovered through rates. KDOE has assumed that those costs can be recovered from all customers. That is a problematic assumption considering the requirement in Chapter 278 that the cost of demand-side management programs may only be assigned to the class or classes of customers who benefit from the programs. KRS 278.285(3).

Further, one must keep in mind Big Rivers' financial situation when considering DSM programs. Increased costs and the reduced revenues resulting from the implementation of an aggressive DSM program reduce Big Rivers' cash flow. The rates supporting Big Rivers' successful plan of reorganization in bankruptcy are founded upon adequate cash flows to meet its obligations. This uniqueness cannot be ignored.

Big Rivers continues to believe that its best course of action, with its current avoided cost and unique financial circumstances, is to make available information to its member distribution cooperatives to allow them to determine what the payback is for investment in electrical energy reducing alternatives or conservation efforts. To the degree that the KDOE has specific information that Big Rivers can disseminate to its members on new alternatives, or programs that are of benefit on a TRC basis with Big Rivers' avoided cost, Big Rivers is interested in assisting its members by making the information available.

2. **<u>Big Rivers' IRP evaluates resource options on the basis approved by the Commission</u>.**

Big Rivers will not protract the debate over TRC versus PVRR versus RIM as the appropriate test for measuring the effectiveness of DSM measures. Two succinct points must be made by Big Rivers concerning this issue to correct continuing misstatements by KDOE. First, the RIM test was used as a screening device by R. W. Beck in the 1995 Study, along with other tests, such as TRC, which were appropriate at the time. The IRP, as noted above, used PVRR and TRC to evaluate DSM versus supply options; it did not employ RIM for this comparison.

Second, while KDOE "sees no reason to exclude" TRC as the primary test of resource options, the Staff has spoken clearly on the KDOE position in the *Staff Report on the Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company*, P.S.C. Case No. 99-430 (September 2000), at page 20:

> However, Staff disagrees with DOE's expansive view of the applicability of the TRC test as well as its contention that minimization of PVRR should not be the primary consideration in the development of a utility's IRP. The TRC test is a measure of expenditures for a <u>DSM program</u>, as both DOE and the Companies acknowledge. Minimizing PVRR has been accepted as the primary criterion for IRPs since the promulgation of 807 KAR 5:058, the regulation which requires the filing of IRPs by Kentucky's major electric utilities. Minimizing utility revenue requirements which would be borne by the utility's customers is entirely consistent with the language of KAR 5:058, which says that utility resource plans are to 'meet future demand with an adequate and reliable supply of electricity at the

lowest possible cost for all customers . . . .'

3. **<u>Big Rivers has accurately assessed the marketability of resources available from DSM and strategic conservation</u>.**

KDOE's mere "belief" that vast (but unquantified) amounts of capacity can be liberated across the country through strategic conservation by retail electric consumers is an insufficient justification for declaring the Big Rivers IRP deficient. KDOE offers no evidence that capacity in any marketable amount or quality is available in Big Rivers' service area. The generalized studies upon which KDOE relies, that discuss savings available "in countries like the United States" (KDOE Supplemental Comments at 4), are not shown by KDOE to have any relevance to conditions in Kentucky, or on the Big Rivers' system. Unlike KDOE, Big Rivers is in the wholesale power market daily, and has a keen awareness of market requirements for wholesale power sales. For the reasons stated in its Initial Comments, Big Rivers is unconvinced by KDOE that there is a realistic opportunity during the study period to marshal sufficient, marketable power through conservation to take to the wholesale market.

4. **<u>The IRP process properly focuses on meeting Big Rivers' system requirements</u>.**

KDOE's proposal that Big Rivers' IRP include strategies for obtaining power resources that can be sold off-system at a profit is contrary to the express purpose of the IRP process. The IRP regulation requires Big Rivers and other major utilities to show how they can "meet future demand with an adequate and reliable supply of electricity at the lowest possible cost <u>for all customers within their service areas</u> . . . ." 807 KAR

5:058. The IRP focus is on the future demand in the Big Rivers service area. Moreover, an IRP study performed under the Commission's regulations is not the appropriate place to report or otherwise disclose merchant plans.

Big Rivers, a rural electric cooperative, operates for the mutual benefit of its members and patrons. It plans for electric power resources to meet the requirements of its members, and vigorously markets those resources off system, if and to the extent that available resources periodically exceed its members' requirements. KDOE presents no compelling evidence that Big Rivers should implement a strategic conservation plan, beyond what is already recommended in the IRP, to reduce sales to its members in hopes of selling that power on the wholesale market at a higher price. Big Rivers is not prepared to expose its members to the risk of acquiring resources solely for resale based upon assumptions about future wholesale power prices.

5. **Amending the IRP regulation is not a proper subject of the Big Rivers IRP.**

KDOE advocates that the Commission "clarify the intent of 807 KAR 5:058, Section 8(2)(a), and require the member cooperatives of Big Rivers (and East Kentucky Power Cooperative) to cooperate with the latter's transmission and distribution planning activities in future IRPs in order to minimize total system costs." KDOE Supplemental Comments at 7. Since the Commission takes no action in IRP cases [the process is concluded by a report issued by the Staff, 807 KAR 5:058 §11(3)], KDOE can obtain no relief in this proceeding. Moreover, since the IRP regulation expressly identifies the utilities that are required to file integrated resource plans [807 KAR 5:058 §2(a)], granting KDOE's request will require an amendment to the regulation, not a clarification.

In any event, the KDOE request is beyond the scope of this proceeding.

6. **<u>The KDOE criticism of the R. W. Beck 1995 Study is misplaced</u>.**

Big Rivers is pleased to respond in more detail to the unjustified KDOE criticisms of the 1995 Study.

a. <u>Utility Load Shape Objectives</u>. KDOE contends that the use of load shape objectives is a qualitative proxy for the RIM test, which it considers to be an anathema to the DSM business. The use of load shape objectives is necessary in the screening of DSM options. In the development of DSM programs, it is beneficial to understand the condition of the utility's supply side needs to determine those areas where DSM programs will provide the largest return. If capacity is needed, the load shifting programs are most beneficial. If energy needs are apparent due to a lack of low cost base load, then conservation programs are more beneficial. Big Rivers would use this approach today in any DSM study implemented as a screening tool.

b. <u>Customer Acceptance</u>. KDOE contends that customer acceptance is a highly subjective criteria. It further asserts that: "The reaction of customers to a DSM program is largely a function of the way the program is designed and administered." Big Rivers disagrees. The technology, which translates into customer convenience, provides the function for which the customer is paying money to obtain from electric energy, i.e., lighting, heating, cooling, appliance usage, etc. Therefore, if the technology does not translate into minimal impact and cost to the consumer, the program design and administration is irrelevant. The KDOE contends that "[i]f the utility pays a higher fraction of the cost of installing a certain technology, for example, the cost to the customer will be correspondingly reduced and its acceptability will increase." And, in the context of the TRC test, this issue is irrelevant.

c. Technical Viability/Maturity. KDOE seems to believe that Big Rivers should base the cost and reliability of meeting its customers' future needs on programs that "have not achieved widespread acceptance in the market." Big Rivers does not use this philosophy on the supply side and does not feel it is appropriate on the demand side either.

The KDOE further speculates about why certain programs were or were not included, and opines that the programs not included have all "been found to offer very large potential efficiency gains in other areas of the country (including the Pacific Northwest, which has electricity *rates* as low as Kentucky's)(emphasis added)." The TRC test precludes using rates and uses the Big Rivers avoided cost in the assessment of programs.

The KDOE shows its lack of understanding of why load shape objectives are important by questioning the poor results of direct load control programs, which are a load shifting program. They scored poorly, because Big Rivers had, and still has, minimal need for peaking capacity. Therefore, the avoided cost under the conditions analyzed is minimal, and the programs do not score well. KDOE points to the study's key recommendation ("Based on Big Rivers current capacity situation and production costs, programs should not derive a benefit based on capacity or demand") as being unclear or unsupported by discussion in the text. It is fundamental that if the utility does not need capacity, programs that reduce capacity will not be of benefit.

The KDOE further contends that five of the programs selected for further analysis should have been quickly screened out, ignoring the fact that the 1999 IRP did not carry them forward.

The KDOE contends that simply because the list of 314 options considered was not in the report that "[t]he list, which probably dates to the early 1990's is outdated today." It is interesting to note that of the references used by the KDOE to support its arguments, Gellings and Chamberlin dates from 1993, and the E Source paper was published in 1992. KDOE does not explain why its sources are impervious to the passage of time.

The most interesting of the KDOE's comments is the conclusion that with the 1999 IRP purported focus on rates, a large class of *potentially* (emphasis added) cost-effective DSM programs was rejected out of hand making it impossible to conform to the basic intent of 807 KAR 5:058, i.e. to develop a plan that meets future demand at the lowest possible costs for all customers. Big Rivers notes that the KDOE has no specific programs that could compete with Big Rivers' avoided cost in the TRC analysis, and contends that the approach used in the 1999 IRP provides the lowest cost approach to meeting future demand.

7. **The market transformation proposal of KDOE is outside the scope of the IRP.**

KDOE's entrepreneurial "market transformation" approach to improving the efficiency of energy consumption remains, in Big Rivers' view, outside the scope of an IRP. Big Rivers accepts that KDOE has a different view, and that it believes in its position. Big Rivers' IRP properly focuses on its regulated activities, rather than potential projects for an unregulated subsidiary.

Conclusion

KDOE has made the serious and unjustified accusation that the Big Rivers' IRP fails to provide an adequate and reliable supply of electricity at the lowest possible cost for all consumers within the Big Rivers service territory. In support of this accusation, it references numerous general studies about what could hypothetically be achieved under a variety of programs, harps about the value of various tests to measure DSM programs, and disparages the value of programs considered because they are outdated (even if more current than some of KDOE's sources). Yet KDOE offers not one substantive program recommendation that it has evaluated on the basis of Big Rivers' avoided cost. Big Rivers' IRP should not be rejected on the basis of KDOE's generalized, hypothetical criticisms, which the traditional procedural schedule does not permit Big Rivers to test through discovery and cross examination.

Big Rivers has stated that the next IRP will include a new report for DSM programs to replace the 1995 Study, and has proposed to sit down with Staff to work out a convenient date for that filing.[3] Big Rivers has offered to use the information available from the KDOE as input to the study. However, the KDOE insists on arguing about the 1999 IRP that (i) selects a DSM program as part of the lowest cost approach to providing an adequate and reliable supply of electricity on a TRC basis, (ii) has no need for supply side expansion and (iii) provides an adequate and reliable supply of electricity to the

---

[3] Big Rivers has requested that its next IRP be due three (3) years from the due date of the 1999 IRP, or at such other time as may be agreed upon to accommodate the Staff's schedule.

customers of Big Rivers.

This the 15th day of December, 2000.

James M. Miller
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Street, P.O. Box 727
Owensboro, KY 42302-0727
(270) 926-4000

Counsel for Big Rivers Electric Corporation

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

November 30, 2000

To: All parties of record

RE: Case No. 1999-429

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

Sincerely,

Stephanie Bell

Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42419 0024

John Stapleton
663 Teton Trail
Frankfort, KY 40601

Honorable Iris Skidmore
Honorable Ronald P. Mills
Counsel for Natural Resources and
Environmental Protection Cabinet
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

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

Honorable James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback &
Miller, P.S.C.
100 St. Ann Building
P.O. Box 727
Owensboro, KY 42302 0727

Honorable Douglas L. Beresford
Counsel for Big Rivers Electric
Hogan & Hartson L.L.P.
555 Thirteenth St., N.W.
Washington, DC 20004 1109

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	))	CASE NO. 99-429

O R D E R

The Natural Resources and Environmental Protection Cabinet, Division of Energy ("KDOE") filed a motion requesting authority to file additional comments addressing the reply comments filed by Big Rivers Electric Corporation ("Big Rivers"). KDOE has included its additional comments in this pending motion. Big Rivers filed a memorandum in opposition to the motion, claiming that KDOE has had more than an adequate opportunity to address all relevant issues. KDOE has in fact already addressed all relevant issues, and there is no need to further delay this proceeding. In the alternative, Big Rivers requests that it be granted 30 days to file additional reply comments in the event that the KDOE motion is granted.

Based on the motion and the response, and being sufficiently advised, the Commission finds that the importance of the issues being investigated in this integrated resource plan filing justifies revising the existing procedural schedule to accept the additional comments tendered by KDOE with its motion and to allow Big Rivers 30 days to file additional reply comments.

IT IS THEREFORE ORDERED that:

1. The motion of KDOE to file additional comments is granted and the comments included in that motion are accepted for filing.

2. Big Rivers shall have 30 days from the date of this Order to file any additional reply comments addressing KDOE's additional comments.

Done at Frankfort, Kentucky, this 30th day of November, 2000.

By the Commission

ATTEST:

Thomas M. Dorman

Executive Director

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC

ATTORNEYS AT LAW

Ronald M. Sullivan
Jesse T. Mountjoy
Frank Stainback
James M. Miller
Michael A. Fiorella
William R. Dexter
Allen W. Holbrook
R. Michael Sullivan
P. Marcum Willis
Anne H. Shelburne
Bryan R. Reynolds
Mark G. Luckett

November 8, 2000

Thomas M. Dorman
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: The Integrated Resource Plan of Big Rivers Electric Corporation,
PSC Case No. 99-429

Dear Mr. Dorman:

Enclosed in response to Kentucky Division of Energy's motion for an exception to the procedural schedule and reply comments are an original and ten copies of the memorandum in opposition and motion to strike of Big Rivers Electric Corporation. Copies of this letter and enclosure have been served on each party to this proceeding.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej
Enclosures

cc: David Spainhoward

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

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

Service List
PSC Case No. 99-429

Elizabeth Blackford, Esq.
Assistant Attorney General
Utility and Rate Intervention Division
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601

Office of the Attorney General of the Commonwealth of Kentucky

Iris Skidmore
Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601

John Stapleton
Director of Energy NREPC
663 Teton Trail
Frankfort, KY 40601

Counsel for Natural Resources and Environmental Protection

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF	**)**	**CASE NO. 99-429**
BIG RIVERS ELECTRIC CORPORATION	**)**	

MEMORANDUM IN OPPOSITION TO MOTION OF KENTUCKY DIVISION OF ENERGY TO AMEND PROCEDURAL SCHEDULE AND MOTION TO STRIKE

Big Rivers Electric Corporation ("Big Rivers") files this memorandum in opposition to the motion of the Kentucky Division of Energy ("KDOE") to amend the procedural schedule to permit KDOE to file additional comments. Big Rivers further moves that the motion, which contains the reply comments KDOE seeks leave to file, be stricken from the record.

The procedural order in this matter, entered by the Commission on April 28, 2000, provides intervenors "the option of filing written comments on issues related to Big Rivers' 1999 IRP." Order, Appendix A. Big Rivers is also given the option to file written comments "in reply to any written comments from intervenors." Id.

KDOE filed comments that were 41 pages in length. Big Rivers filed comments replying to the comments by the intervenors, including KDOE, on October 27, 2000, in accordance with the procedural schedule.

KDOE offers no justification for amending the procedural schedule in this case to allow additional comments by it, except to say that KDOE should be permitted to "file additional comments to clarify issues raised in [Big Rivers' reply comments]." KDOE motion at 1. The motion should be denied for several reasons.

First, neither the law nor fundamental fairness justify giving KDOE another bite at the apple. KDOE's desire to "clarify issues raised" by Big Rivers turns the procedural schedule on its head. It is KDOE that created the issues to which Big Rivers replied in its comments filed October 27, 2000. KDOE has had the opportunity to propound two sets of interrogatories to Big Rivers, to cross examine Big Rivers' representatives for over two hours, and to file in excess of 40 pages of comments in which KDOE made extensive assertions of fact that were not subject to cross-examination or any other inquiry. KDOE has had a lopsided opportunity to make its points.

Second, KDOE's tendered supplemental reply comments add nothing to this proceeding. Without undertaking to respond to the merits, it is instructive to note that the KDOE reply comments are broken down into sections on "issues on which KDOE and Big Rivers agree," and "issues on which KDOE and Big Rivers disagree." KDOE's cross-examination of Big Rivers' representatives at the informal conference and its insistence on protracting the procedural schedule, reflect an Orwellian insistence that this proceeding continue until Big Rivers agrees with each position taken by KDOE. There are issues on which KDOE and Big Rivers will not agree, regardless of how many questions are asked of Big Rivers' representatives and regardless of the number of the pages of comments filed by KDOE. This proceeding must conclude, and it should conclude, as contemplated by the Commission, with the reply comments filed by Big Rivers on October 27, 2000.

Finally, if the KDOE motion is granted and its supplemental comments are filed, Big Rivers is entitled to respond to those supplemental comments, and should be given 30 days to do so. It is Big Rivers that has the burden of showing that it can meet future power requirements on its system with an adequate and reliable supply of electricity at the lowest possible cost. 807

KAR 5:058. The Kentucky Rules of Civil Procedure regarding trial procedure, CR 43.02, provide that: "In the argument, the party having the burden of proof shall have the conclusion and the adverse party the opening." CR 43.02(e). Although the Kentucky Rules of Civil Procedure are not applicable to proceedings before the Public Service Commission, fundamental fairness requires that the party with the burden of proof have the last argument, as is presently provided by the Commission in its procedural order.

KDOE has incorporated into its motion the supplemental comments it wishes to file, rather than follow the usual practice of attaching those comments to its motion. If KDOE's motion is denied, the entire motion must therefore be stricken from the record, and Big Rivers so moves.

Wherefore, Big Rivers asks that the Commission:

1. Deny the KDOE motion to amend the procedural schedule,
2. Strike the KDOE motion from the record,
3. In the alternative, if the KDOE motion is granted, to permit Big Rivers 30 days in which to reply to the KDOE supplement comments, and
4. To grant Big Rivers all other relief to which it is entitled.

This the 8th day of November, 2000.

James M. Miller

James M. Miller
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Street, P.O. Box 727
Owensboro, KY 42302-0727
(270) 926-4000

Counsel for Big Rivers Electric Corporation

RECEIVED
NOV 06 2000
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

**THE INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC CORPORATION) CASE NO. 99-429**

* * * * * * * * * * * * * * * *

MOTION FOR AN EXCEPTION TO THE PROCEDURAL SCHEDULE AND KENTUCKY DIVISION OF ENERGY'S REPLY COMMENTS

Comes the Natural Resources and Environmental Protection Cabinet, Division of Energy, Intervenor herein, and moves for an exception to the procedural schedule in Case No. 99-429, to permit KDOE to file additional comments to clarify issues raised in the "Reply of Big Rivers Electric Corporation to Intervenor Comments," dated October 26, 2000. If this motion is granted, KDOE respectfully offers the following comments for inclusion in the case record.

Issues on Which KDOE and Big Rivers Agree

1. Big Rivers' 1999 IRP shows that Big Rivers can adequately and reliably meet the future demand of its members. Big Rivers Reply Comments at 1–3. KDOE has never questioned this proposition. Our primary concern relates to whether the costs to customers will be minimized.

2. KDOE supports Big Rivers' efforts to acquire demand-side resources through the load-shifting and interruptible rate programs recommended in the IRP. KDOE Comments at 6.

3. KDOE supports Big Rivers' use of distributed generation to identify cost areas in the expansion of the Big Rivers transmission systems and its member cooperatives' distribution systems that could be reduced with distributed generation. Big Rivers Reply Comments at 8.

4. KDOE supports Big Rivers' expressed intention to consider the use of local integrated resource planning (LIRP), to the degree feasible, prior to preparing its next IRP filing and in its interim planning of transmission system improvements. Big Rivers Reply Comments at 12-13.

5. KDOE supports the existing DSM programs operated by Big Rivers and its member cooperatives, to the extent that they lower the total cost of energy services to customers.

Issues on Which KDOE and Big Rivers Disagree

1. Big Rivers continues to confuse costs and rates. Big Rivers states: "DOE likewise errs in its criticism of Big Rivers' focus on its rates to customers as the primary measure of the cost-effectiveness of resource options. Big Rivers believes that an IRP that strives to reduce or contain a utility's revenue requirements conforms with the mandate of 807 KAR 5:058." Reply Comments at 5. These two sentences themselves clearly illustrate Big Rivers' confusion of this issue.

Rate impacts and revenue requirements are not the same thing. Rates and costs are not the same thing. Customers' rates may go up, but if improved energy efficiency delivers the same energy services with significantly reduced consumption, their overall costs – their utility bills – will decrease. Customers write checks every month to pay utility bills, not rates. If a DSM program causes participating customers' electric rates to go up by 3 percent, for example, but simultaneously cuts their consumption by 30 percent, the participants' total energy bills will decrease by 27.9 percent. If enough customers participate in the DSM program, the total of all energy bills paid by customers will decrease, and the average energy bill across all customers will decrease. The utility's *revenue requirements will decrease*, since in the long run the total costs to the utility (revenue requirements) equal the total revenues (total energy bills paid by customers).[1] The DSM program's Utility Cost (UC) ratio will be found to be greater than one. Participating customers will clearly be better off, and the "average" customer will be better off. Rates, however, will be 3% higher, and the energy bills of non-participants will increase by 3 percent.

Big Rivers may believe that an IRP that strives to reduce or contain a utility's revenue requirements conforms with the mandate of 807 KAR 5:058, but its 1999 IRP does not and cannot succeed in minimizing revenue requirements. Instead, it is designed to minimize rates. KDOE Comments at 4-7. The two goals are very different and can be mutually exclusive, as is illustrated by the example above and by successful strategic conservation-type DSM programs operated by hundreds of utility companies across the United States. Such programs typically cause rates to go up slightly, but reduce total energy bills, average energy bills, and *the utility's revenue requirements*. By ruling the very large class of strategic conservation-type DSM programs out of consideration in its IRP, Big Rivers has ensured that revenue requirements (utility costs) will not be minimized. For the same reason, total resource costs will not be minimized, and customers will end up paying higher costs for energy services than they otherwise would.

2. Big Rivers cites a difference between the positions of KDOE and the Commission Staff on the proper role of the TRC Test versus the UC Test, but Big Rivers' 1999 IRP slights both of these performance measures by focusing on rate impacts. The UC Test (or Present Value

[1] Gellings, Clark W. and John H. Chamberlin, *Demand-Side Management Planning*, 1993, Fairmont Press, p. 267.

of Revenue Requirements [PVRR] test) is a measure of the total energy bills across all customers, while the TRC Test is a measure of the total cost of energy services across all customers. The main difference is that the TRC Test includes customers' equipment and operating costs and benefits while the UC Test does not.[2] Although the UC Test, as reflected by the PVRR, has frequently been accepted as the primary criterion used by utilities at the stage in their analysis when they integrate the supply side of their resource plans with their demand side, KDOE sees no reason to exclude consideration of customers' equipment and operating costs and benefits at any stage of the analysis.

Big Rivers' 1999 IRP, however, is designed to minimize neither total resource costs nor present value revenue requirements (utility costs), but rate impacts (as measured by the RIM Test). Again, costs and rates are not the same thing. The discussion included with our preceding point above also applies here.

3. Big Rivers holds that "the potential capacity and energy which could be freed up by strategic conservation is small, tends to be unreliable and, consequently, essentially non-dispatchable by the utility. Intersystem sales at the best prices are typically made in standard blocks of 50 MW, far more capacity than could be expected from a strategic conservation program on the Big Rivers system." Reply Comments at 6. KDOE disagrees strongly with this conclusion.

KDOE's position is closer to that expressed by E Source in numerous publications, including their 1992 Strategic Issues Paper on institutional market barriers, which stated that "Well over half of the energy used to cool and ventilate buildings in countries like the United

---

[2] *Ibid.*, pp. 260-67.

States can be saved by improvements that typically repay their cost within a few years." Other analyses have found comparable potential savings in lighting, drivepower, office equipment and other end-uses. KDOE Comments at 21.

Focusing on commercial buildings, KDOE cited the Environmental Energy Technologies Division of the Lawrence Berkeley National Laboratory, which estimated that "If only tune-ups and performance monitoring of existing buildings were performed, average energy use could be reduced by about 20%. If proven efficiency measures were applied when a building is retrofitted (usually about every 15 years), about 50% reduction could be attained. The full range of efficiency measures that can be designed and incorporated into new buildings could bring about an energy reduction of as much as 75%."[3] Other estimates (for example, by E Source) are even higher. KDOE Comments at 24.

KDOE believes that potential efficiency gains in the industrial sector are huge as well. Improvements in industrial process design can reduce both operating and capital costs, yielding immediate paybacks. KDOE Comments at 26. Large savings can be achieved in industrial motor and drive systems, process controls, new materials processing technologies, and employee-suggested improvements that reduce both energy waste and the generation of pollution.[4] Big Rivers' assumption that KDOE is focusing primarily on residential DSM programs is erroneous. Big Rivers Reply Comments at 6, paragraph 1.

Technical potential studies of the total size of the demand-size resources in other jurisdictions have found that roughly one-third of all electricity consumption can be saved

[3] Lawrence Berkeley National Laboratory, "Creating High-Performance Commercial Buildings," *EETD News*, Fall 1999, pp. 1-2.
[4] Hawken, Paul, Amory Lovins, and L. Hunter Lovins, *Natural Capitalism: Creating the Next Industrial Revolution*, 1999, Boston: Little, Brown and Company, pp. 48-81 and footnotes.

through cost-effective measures in the long run.[5] Detailed technical studies by E Source lead to the conclusion that the fraction that could be saved cost-effectively through whole-system design in all sectors of the economy is even higher.[6]

KDOE has already addressed Big Rivers' point about the reliability of demand-side resources in our Comments at 8, last paragraph.

4. Big Rivers states that its current ability to sell excess capacity intersystem at a profit does not make strategic conservation a "win-win" situation, and goes on to say that "Big Rivers would not propose to implement a strategic conservation program solely to free up capacity and energy for sale off system at an assumed profit." Reply Comments at 6-7. Big Rivers seems to be missing a business opportunity and overlooking substantial potential benefits to its customers, which would include: 1) significantly lower energy bills for participating customers as a result of their reduced consumption; and 2) lower rates and bills for all customers, including non-participants (as long as Big Rivers continues to be able to sell excess capacity intersystem at a profit). These benefits to customers could be expected to increase customer loyalty, which may have important business implications for Big Rivers if the market becomes more competitive. In this case, planning to free power for sales off-system would not conflict with the goal of meeting system requirements at the lowest cost, but would contribute directly toward achieving that goal. The fact that Big Rivers is not facing an immediate capacity shortage is irrelevant to this promising strategy, which could lead to even lower total system

[5] Miller, Peter M., Joseph H. Eto, and Howard S. Geller, *The Potential for Electricity Conservation in New York State*, American Council for an Energy-Efficient Economy, September 1989.
[6] E Source, *Technology Atlas* series.

costs (TRC and PVRR) and much greater benefits to customers than the strategy recommended by the 1999 IRP.

5. Big Rivers claims that it lacks the legal authority to include member cooperative distribution planning in its IRP. Reply Comments at 9. The member cooperatives, however, are subject to regulation by the Commission. KDOE requests that the Commission clarify the intent of 807 KAR 5:058, Section 8(2)(a), and require the member cooperatives of Big Rivers (and East Kentucky Power Cooperative) to cooperate with the latter's transmission and distribution planning activities in future IRPs in order to minimize total system costs.

6. Big Rivers disagrees with KDOE's criticism of the 1995 DSM study by R.W. Beck, but does not address any of the specific substantive points we raised about the report's serious flaws.

7. Big Rivers considers most of KDOE's constructive suggestions about future DSM programs to be "outside the scope of an IRP proceeding" and more appropriate for the legislature to address. Reply Comments at 13-14. KDOE would not have made these suggestions unless we believed that all of them are measures that a utility company can and should take, or at least seriously consider, when it develops plans to meet customers' needs for energy services in the lowest-cost way. We believe that in general, the market transformation approach offers a more cost-effective way to achieve improved energy efficiency than the traditional utility DSM program strategy that depends on offering ongoing rebates for the purchase of specified energy-efficient technologies.

Although KDOE acknowledges that the 1999 IRP sets forth one way for Big Rivers to meet future demand with an adequate and reliable supply of electricity, we maintain that it does not do so at the lowest possible cost for all customers within its service area. We therefore maintain that the IRP fails to meet the provisions of 807 KAR 5:058, and we stand by the recommendations made in our Comments at 1.

VERIFICATION

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

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

Subscribed and sworn to before me by Geoffrey M. Young, this the 6th day of November, 2000.

Jean A. Cook
NOTARY PUBLIC

My Commission Expires: 1/10/2002.

Respectfully submitted,

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

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION CABINET

CERTIFICATE OF SERVICE

I hereby certify that on the 6th day of November, 2000 a true and accurate copy of the foregoing **MOTION FOR AN EXCEPTION TO THE PROCEDURAL SCHEDULE AND KENTUCKY DIVISION OF ENERGY'S REPLY COMMENTS** was mailed, postage pre-paid, to the following:

David A. Spainhoward, Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY. 42419 0024

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

Hon. James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, KY. 42302 0727

Hon. Douglas L. Beresford
Counsel for Big Rivers Electric
Hogan & Hartson L.L.P.
555 Thirteenth St., N.W.
Washington, DC. 20004 1109

Iris Skidmore

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC

ATTORNEYS AT LAW

October 26, 2000

RECEIVED
OCT 27 2000
PUBLIC SERVICE COMMISSION

Thomas M. Dorman
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: The Integrated Resource Plan of Big Rivers Electric Corporation, PSC Case No. 99-429

Dear Mr. Dorman:

Enclosed are an original and ten copies of the Reply Comments of Big Rivers Electric Corporation in this matter. I certify that a copy of this letter has been served on the parties of record by mailing a copy of same to them, on this date, postage prepaid.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej

cc: Service List
David Spainhoward

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

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

RECEIVED
OCT 27 2000
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC CORPORATION)

CASE NO. 99-429

REPLY OF BIG RIVERS ELECTRIC CORPORATION TO INTERVENOR COMMENTS

Big Rivers Electric Corporation ("Big Rivers") elects the option provided to it in the procedural order herein of replying to the comments of both intervenors in this matter: the Attorney General and the Division of Energy ("DOE"). Big Rivers filed its integrated resource plan pursuant to 807 K.A.R. 5:058 ("IRP") on March 21, 2000. The Attorney General and the DOE intervened, filed information requests, participated in the informal conference on September 8, 2000, and filed written comments on the Big Rivers IRP. The comments of the intervenors, while intended to be constructive, raise issues that require some comment and rebuttal by Big Rivers.

The Big Rivers IRP shows that Big Rivers can adequately and reliably meet the future demand of its members.

Big Rivers' IRP clearly satisfies the threshold requirement of 807 K.A.R. 5:058 by showing that Big Rivers can "meet future demand with an adequate and reliable supply of electricity . . . ." 807 K.A.R. 5:058. Before responding to the specific comments of the intervenors, Big Rivers must reemphasize that the amount and nature of "future demand," which defines Big Rivers' supply responsibility during the period covered by the IRP, are important factors in resolving the best source for meeting that requirement.

Big Rivers obtains the majority of its capacity and energy under the Power Purchase

Agreement with LG&E Energy Marketing ("LEM"). The maximum capacity available to Big Rivers under that agreement increases over the period of the IRP study to 597 MW in 2001, 717 MW in 2011, and 800 MW in 2012. Big Rivers additionally obtains 178 MW from SEPA under a contract for peaking capacity. A retail industrial customer on the system of one of Big Rivers' member distribution cooperatives is planning to install a nominally rated 62 MW cogeneration facility, that is anticipated to come on line in 2001. Considering all of these capacity sources, Big Rivers is capacity deficient only in the following years:

Year	Deficit
2008	6 MW
2009	25 MW
2010	56 MW

With the cogeneration unit in operation, Big Rivers is projected to require only about 60% of the annual energy available under the LEM agreement in 2010. The projected energy deficits occur in the following years:

Year	MWh Deficit	Hours Deficit
2008	6	2
2009	164	18
2010	1,679	72

This assessment of capacity and energy deficits clearly demonstrates that Big Rivers is in need of only peaking resources for a few hours per year to meet its projected power supply requirements. Big Rivers has very little need for additional capacity and extremely limited exposure to high-priced marginal energy throughout the study period.

If, on the other hand, the cogeneration resource does not materialize, Big Rivers must begin planning for capacity deficits that will start to occur in 2004. The IRP finds "that after the commercial/industrial load management program, combustion turbines and peaking power purchases reflect the most economical method to meet the capacity deficiency and minimize the potential financial risks associated with spot market purchases." IRP at VII-2, paragraph 3.

Big Rivers' choice of supply options provides its members with their power requirements at the lowest possible cost.

Big Rivers' IRP further satisfies the requirements of 807 K.A.R. 5:058 that Big Rivers meet future power requirements on its system with an adequate and reliable supply of electricity "at the lowest possible cost . . . ." 807 K.A.R. 5:058. It is on this subject that Big Rivers and the intervenors, especially DOE, disagree. DOE, however, seems to be caught up more in procedure than in the outcome of the IRP.

As Big Rivers demonstrates in its IRP, it plans to satisfy its future power requirements with power from the LEM contract, the SEPA contract and from its commercial/industrial load management programs. Big Rivers appreciates the Attorney General's support of its customer-based approach to load management (including the large industrial expansion tariff and the voluntary curtailable load tariff), but believes that the Attorney General's concern about the distributive generation aspect of that approach threatening the viability of the entire concept is somewhat misplaced. First, Big Rivers must have miscommunicated its view of Willamette's distributed generation. See Attorney General Comments at 3. Big Rivers realizes that distributed generation should run as much as possible to increase its feasibility for the owner. Big Rivers does see the Willamette 62 MW as being very attractive, although it is admittedly not typical of cogeneration projects one would ordinarily expect to see.

The resources contracted for combined with Big Rivers' commercial/industrial load management programs provide adequate power to meet the requirements of the Big Rivers system. Consistent with the suggestion of the Attorney General, Big Rivers is studying interruptible and time-of-day tariffs which may enhance the flexibility already provided by its large industrial expansion tariff and its voluntary curtailable load tariff. With respect to distributed generation, Big Rivers also mentioned at the informal conference that existing retail customer-owned emergency generation, such as is found at chicken production operations, offers a potential source of peaking power that Big Rivers is currently investigating. The customer has already committed finances to that generation, and should be pleased to have an opportunity to recoup some of that investment.

Regarding the Attorney General comments on Net Metering, Big Rivers agrees to consider Net Metering prior to filing its next IRP. Big Rivers also agrees with the Attorney General that "extensive regulations and the cost of special metering from the PURPA era stand in the way of small generation." Attorney General Comments at 5. However, Big Rivers further agrees that if Net Metering tariffs that are beneficial to Big Rivers and its members can be designed, then the members' customers should have the opportunity to participate.

DOE is highly critical of the cost-effectiveness measures employed in arriving at this conclusion, and argues that the failure of Big Rivers to use the Total Resource Cost ("TRC") test, also known as the "All Ratepayers' Test," in evaluating each DSM option invalidates the entire IRP. DOE makes several mistakes in its comments. The first is its conclusion that the IRP regulation essentially requires use of the TRC test as the primary criterion to show whether all ratepayers are being optimally served. DOE Comments at 2. The Public Service Commission staff ("Staff") has expressly disagreed with this conclusion in the *Staff Report on the Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company*, P.S.C. Case No. 99-430 (September 2000), at page 20.

DOE likewise errs in its criticism of Big Rivers' focus on its rates to customers as the primary measure of the cost-effectiveness of resource options. Big Rivers believes that an integrated resource plan that strives to reduce or contain a utility's revenue requirements conforms with the mandate of 807 K.A.R. 5:058. This position is also consistent with the conclusion of the Staff in the *Staff Report on the Integrated Resource Plan Report of Louisville Gas and Electric Company and Kentucky Utilities Company*, P.S.C. Case No. 99-430 (September 2000), at page 20:

> Minimizing utility revenue requirements which would be borne by the utility's customers is entirely consistent with the language of KAR 5:058, which says that utility resource plans are to 'meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers . . . .'

In fact, Staff found that "[m]inimizing PVRR [Present Value of Revenue Requirements] has been accepted as the primary criterion for IRPs since the promulgation of 807 K.A.R. 5:058 . . . ." Id. (emphasis added).

Big Rivers' focus on its costs, and on keeping its rates low is particularly appropriate under the circumstances. On July 17, 1998, Big Rivers implemented a plan of reorganization ("Plan") that resolved its reorganization under Chapter 11 of the Federal Bankruptcy Code. The Plan reflected that Big Rivers had convinced its creditors and the bankruptcy court that it should emerge from bankruptcy with rates which were lower than when it entered bankruptcy. Part of

Big Rivers' commitment to the bankruptcy court, to its creditors, and to the Commission during the approval of its reorganization plan was to keep costs and rates down.

DOE offers no proof that its emphasis on residential DSM will keep rates down. In fact, DOE candidly acknowledges that rate increases are an acceptable consequence of DSM program implementation, DOE Comments at 17-18:

> Comments made by representatives of Big Rivers at the informal conference indicate that they sincerely believe that the interests of the customers and the utility company are best served when rates are kept at the lowest possible level. This, however, is a serious misconception. To implement certain types of DSM programs [also known as strategic conservation programs] that greatly benefit customers and reduce the utility's revenue requirements, it may sometimes be necessary to accept a certain amount of upward pressure on rates. Such strategic conservation programs can and should be combined with load-shifting programs that tend to reduce rates, yielding a relatively neutral rate impact overall.

If Big Rivers correctly understands the preceding statement by DOE, the effects of strategic conservation are to expose Big Rivers to the expense and risks of implementing a program, and to expose retail customers to rate increases, with the final result "yielding a relatively neutral rate impact overall." This does not make a compelling case for strategic conservation; it reinforces Big Rivers' position that strategic conservation is not a viable DSM program for Big Rivers under the circumstances presented in the study period.

The current ability of Big Rivers to sell excess capacity intersystem at a profit does not, as DOE suggests, make strategic conservation a "win-win" situation. First, the potential capacity and energy which could be freed up by strategic conservation is small, tends to be unreliable and, consequently, essentially non-dispatchable by the utility. Intersystem sales at the best prices are typically made in standard blocks of 50 MW, far more capacity than could be expected from a strategic conservation program on the Big Rivers system. Second, Big Rivers understands the

IRP process to involve planning to meet system requirements at the lowest cost, not planning to free power for sales off-system. 807 K.A.R. 5:058. Big Rivers would not propose to implement a strategic conservation program solely to free up capacity and energy for sale off system at an assumed profit.

DOE mistakenly states that Burns & McDonnell selected three DSM programs (items 7, 8, and 9) from the 1995 R. W. Beck study as "'viable,' 'cost effective' and worthy of further analysis when developing the 1999 IRP." DOE Comments at 5. DOE references the Burns & McDonnell response to DOE Item 14, 1st set. DOE argues at some length that those three DSM programs should have been discarded due to not passing various DSM tests.

Burns & McDonnell made no mention of the above programs in the response to DOE Item 14, 1st set, nor did it find from the screening analysis that any of the residential programs from the 1995 study were worthy of further analysis in the TRC analysis of supply and DSM programs performed in the 1999 IRP. Burns & McDonnell discarded the referenced DSM programs from further consideration based on an analysis of the Total Resource Cost (TRC) and Rate Impact Measure (RIM) assessments in the 1995 DSM study and an assessment of the current conditions of Big Rivers versus those in 1995. The TRC and RIM are accepted measurements to determine the viability of DSM programs.

Big Rivers' 1999 IRP properly assesses potentially cost-effective improvements to and more efficient utilization of *transmission or distribution facilities.*

DOE incorrectly accuses Big Rivers of failing to assess potentially cost-effective improvements to and more efficient utilization of transmission or distribution facilities. As occurs throughout the DOE Comments, DOE's conclusions stem from false assumptions.

Initially, it is important to note that the IRP found that the Big Rivers transmission system is adequate to deliver "the total needs of the Big Rivers system without major modification over the study period." IRP at II-7. From an efficiency standpoint, the Big Rivers transmission system has little room for improvement, with system losses for 1999 of only 1.36 percent.

Notwithstanding the IRP finding and the current efficiency of the transmission system, the IRP recommends pursuit of opportunities in cogeneration, commercial/industrial load management and distributed generation as means to meet future needs. IRP at VII-2 and 3. These recommendations are integral to the concept of "more efficient utilization of existing utility generation, transmission, and distribution facilities." 807 K.A.R. 5:058 §8(2)(a). For example, one of the intents in recommending use of distributed generation is to identify cost areas in the expansion of the Big Rivers transmission system and of the members' distribution systems that could be reduced with distributed generation. Big Rivers has already incorporated distributed generation in its checklist for transmission planning.

DOE ignores the clear language of the regulation and reality when it insists that the distribution systems of Big Rivers' member distribution cooperatives must be included in the transmission and distribution system analysis called for by 807 K.A.R. 5:058 §8(2)(a). The regulation expressly names the utilities that are required to file IRPs. 807 K.A.R. 5:058 §2(a). None of the Big Rivers member distribution cooperatives are listed.

The information required to be included in the IRP by 807 K.A.R. 5:058 §8(2)(a) relates to facilities of "the utility" or, at most, facilities under the control of the utility. For purposes of the regulation, Big Rivers is that utility.

Each Big Rivers member distribution cooperative is a separate and distinct cooperative corporation organized under Chapter 279 of the Kentucky Revised Statutes. The members own Big Rivers and elect the Big Rivers board of directors. Big Rivers has no legal authority to require the distribution cooperatives "to establish a mechanism for sharing information about distribution system planning among Big Rivers and the other member cooperatives," including their "analyses of options and least-cost distribution system plans." DOE Comments at 10. Big Rivers does not have responsibility for planning any distribution cooperative facilities. Big Rivers' role in distribution planning is to consult with its member distribution cooperatives about the transmission costs associated with the addition and location of new distribution-owned substations. The IRP regulation does not require Big Rivers to include member distribution cooperative distribution planning in its IRP, and Big Rivers lacks the legal capacity to do so.

As noted in the IRP Executive Summary, IRP at I-2: "(T)his IRP . . . will not be similar to the filings of the other utilities in the Commonwealth." Big Rivers looks different from a vertically-integrated investor-owned utility that owns its own distribution system, and even different from the other generating and transmission cooperative in Kentucky, which owns the distribution substations on its system.

The 1995 R. W. Beck DSM Planning Study is an adequate basis for the DSM conclusions in the Big Rivers 1999 IRP.

The DOE raises numerous concerns about the DSM study prepared by R. W. Beck in 1994 and 1995 (the "Beck Study"). Big Rivers disagrees with this criticism. R. W. Beck is a nationally recognized firm in the demand and supply side resource planning area. DOE offers no credible basis on which the Staff could conclude that any different conclusion would result from a more current DSM study skewed by use of DOE's preferred screening methodologies. In fact, DOE's comments on the Beck Study appear to constitute more differences of opinion than fundamental flaws. DOE Comments at 16-17.

The Beck Study analyzed several demand side programs in the context of Big Rivers' supply situation at the time. Although Big Rivers has experienced dramatic changes in many respects since the last IRP (IRP at I-1 and 2), Big Rivers still has a low cost of marginal energy, and can meet all but a small portion of its supply needs in 2008, 2009 and 2010 with its existing resources. Therefore, the basic cost concepts used to screen programs are still valid.

While the Beck Study is adequate for purposes of the 1999 IRP, Big Rivers states that it fully intends to perform a new DSM analysis in connection with its next IRP, which Big Rivers has requested be due three (3) years from the due date of the 1999 IRP, or at such other time as may be agreed upon to accommodate the Staff's schedule[1]. The emergence of Big Rivers from bankruptcy with a dramatically reduced staff and an emphasis on cost reductions made performing a new study for this IRP problematic. Big Rivers does recognize the role of DSM in integrated resource planning, and will continue to appropriately address DSM in the preparation of its next IRP.

The 1999 Big Rivers IRP satisfies all requirements of 807 K.A.R. 5:058.

DOE erroneously concludes that the Big Rivers 1999 IRP fails to meet the requirements of 807 K.A.R. 5:058. The underpinnings of the DOE argument have been rebutted above. But more important, the Big Rivers IRP fully complies with the requirements of 807 KAR 5:058 by clearly, rationally and measurably demonstrating how Big Rivers will provide "an adequate and

[1] Big Rivers strongly disagrees with the unreasonable recommendation of the DOE that Big Rivers file its next IRP in one year.

reliable supply of electricity at the lowest possible cost for all customers."

Big Rivers points to the fact that over the next 12 years and beyond it has no need for additional power supply investment under the most likely case. It has a marginal cost of energy that makes it difficult for conservation efforts to be readily embraced by its customers. It is finding opportunities to offset costs by buying back retail energy from its customers during certain hours of the year and selling it into, or avoiding purchasing from, the wholesale market. The reliability of the IRP recommendations are significant with little reliance on market costs, minimal use of delivery over the bulk transmission system, and the ability to avoid using the energy buy-back program if it is not economical.

Big Rivers joins in DOE's desire to make constructive use of the IRP process, with Big Rivers' ultimate goal being to benefit its members and, by extension, the ultimate retail consumer in Western Kentucky. Big Rivers desires to begin taking advantage of the expertise and resources available from DOE, and will seek input from DOE and the Attorney General in advance of its next IRP filing. A constructive dialogue among DOE, the Attorney General and Big Rivers in advance of the original filing date for the Big Rivers IRP in April of 1998, would have been far more useful to the process than the DOE's after-the-fact, adversarial approach to this IRP proceeding. That should also be a more appropriate role for DOE, whose legislative mandate is program development.[2]

---

[2] The Division of Energy within the Department for Natural Resources of the Natural Resources and Environmental Protection Cabinet ("NREPC") was made responsible for the following statutory duties of the NREPC found in KRS 224.10-100 by 1990 Ky. Acts, ch.325, sec. 14:

> (28) Develop and implement programs for the development, conservation, and utilization of energy in a manner to meet essential human needs while maintaining the Kentucky economy at the highest feasible level. The programs shall include:

Reply of Big Rivers to DOE Additional Comments

The last 22 pages of DOE's comments consist of suggestions about alternative ways of operating a utility and planning for resource requirements. Big Rivers respects the effort DOE put into developing these suggestions, but the suggestions have limited applicability to Big Rivers.

Big Rivers appreciates the information provided by DOE pertaining to local integrated resource planning ("LIRP"), a relatively new concept in resource planning, under which a utility uses localized customer-based energy efficiency measures, load control and shifting, distributed generation, fuel-switching and alternative rates to defer and reduce capital expenditures. Big Rivers will consider LIRP prior to the preparation of its next IRP filing and in its interim planning of transmission system improvements. As noted in the section of these comments concerning transmission planning, Big Rivers already considers the potential role of distributed generation in transmission planning. However, Big Rivers agrees with E Source that this

---

> (a) Central access for collection, maintenance, and analysis of data and information on all forms of energy supplies, demand, conservation, and related subjects;
>
> (b) Formulation of a contingency plan to cope with any energy shortage which may occur from time to time. The contingency plan shall relate to the curtailment, allocation, planning, and management of all forms of energy;
>
> (c) Development and implementation of major energy conservation programs involving all sectors of the Kentucky economy including energy audits of educational facilities and state owned buildings; and
>
> (d) Provision for the application of appropriate technologies with regard to alternate energy development, including the development of solar and other renewable resources and small scale hydroelectric plants, and, promotion, when feasible, of the production of energy from other resources such as solid waste and biomass;

(29) Enter into agreements, administer grant programs, and serve as liaison with the federal government and other states regarding the programs mandated by subsection (28) of this section; . . . .

approach will require cultural change, extensive information and money.

LIRP would require Big Rivers and its members to jointly plan all transmission (Big Rivers) and all distribution (the members) projects with the common goal of minimizing cost and maintaining reliability. This would go well beyond the level of joint planning which now occurs, and which is outlined on page nine, above. Meeting these two objectives with LIRP requires extensive end-user information to evaluate customer uses and needs, including an elaborate meter-reading effort. Identifying the cause of the localized peak load growth is necessary before the lowest cost solution can be determined. As noted earlier in these comments, Big Rivers only has three wholesale member/customers, no retail customers, no retail service area, no retail distribution responsibility or authority, and is consequently not in control of such information. Also, an extensive margin (rate and cost) analysis of customer use load profiles is necessary, both from Big Rivers' and the member cooperative's perspective. This data intensive and analytically demanding effort is expensive. DSM program administration requires funding (e.g., for customer education and information dissemination). An ongoing evaluation of the effectiveness of the programs implemented would be necessary and costly. Undoubtedly, short-term pressure to increase rates would result from such efforts. As noted above, that is a strong negative factor for Big Rivers.

DOE also urges Big Rivers to become a player in the market for energy-efficient design services (even to the point of creating a non-jurisdictional architectural-engineering-design subsidiary), to promote market transformation initiatives by joining the Midwest Energy Efficiency Alliance, and to work to change legislation, regulations and codes that present barriers to the use of energy-efficient building designs. These are, however, ideas that are outside the scope of an IRP proceeding, most of which should probably be addressed in the legislature.

This the 26th day of October, 2000.

James M. Miller

James M. Miller
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Street, P.O. Box 727
Owensboro, KY 42302-0727
(270) 926-4000

Counsel for Big Rivers Electric Corporation

Service List
PSC Case No. 99-429

Elizabeth Blackford, Esq.
Assistant Attorney General
Utility and Rate Intervention Division
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601

Office of the Attorney General of the Commonwealth of Kentucky

Iris Skidmore
Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601

John Stapleton
Director of Energy NREPC
663 Teton Trail
Frankfort, KY 40601

Counsel for Natural Resources and Environmental Protection

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

RECEIVED
OCT 2 2000
PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	Case No. 99-429

COMMENTS OF THE ATTORNEY GENERAL

In March 2000, Big Rivers Electric Corporation (BREC) filed its 1999 Integrated Resource Plan (IRP). The IRP addresses its future plan for providing electric service to the three cooperatives it serves in Kentucky. The IRP includes a load forecast and the company's plan for both supply and demand side resources to meet projected future needs. Following its review of the plan, the Office of Attorney General of the Commonwealth of Kentucky offers the following comments.

The 1999 IRP filed by BREC differs from BREC's previous IRPs. Previously, BREC had substantial surplus capacity. As a result of its restructuring, BREC's current IRP presents a different picture in which it now uses its available capacity and must find ways to deal with future growth in loads. Since the restructuring of the utility, BREC's customers have been willing to expand operations. New customers have located in the service territory. As a result, BREC has experienced significant growth in recent years. That growth, together with strong arbitrage sales, has allowed BREC to hold rates down and, possibly, to eliminate a future rate increase called for in the workout plan. The growth has also pushed BREC into a possible capacity deficiency situation.

The 1999 BREC IRP looked at a number of options to deal with a potential future capacity shortfall. Options explored included simple cycle and combined cycle gas-fired units and customer demand reduction programs, such as interruptible loads and distributive generation. Analysis concluded that the customer-based programs were more cost effective than adding gas-fired capacity. Since the IRP was completed, the cost of natural gas has risen significantly, nearly 50%. Had today's higher gas prices (which are much higher than the IRP's high gas price scenarios) been included in the IRP, BREC's decision to follow customer-based options would have looked even more attractive. Therefore, the plan to rely on customer-based programs is best for both BREC and its cooperatives' members. Though this Office endorses BREC's customer-based approach, the proposed implementation of the programs is problematic.

BREC has developed innovative approaches to control load growth. For instance, Schedule 10 assures current customers that new customer loads exceeding 5 MW will not result in current customer loss of access to low cost power. Schedule 10 helps assure present customers that capacity will be available to them in the future at reasonable costs. This is only fair as these customers paid relatively high prices for this capacity in the past when the capacity was newly built.

BREC has shown innovation in its encouragement of distributive generation. By encouraging distributive generation, BREC can avoid adding new capacity, the member cooperative can avoid some additions to the transmission and distribution system, and members can reduce costs. Nevertheless, the office must question whether BREC's understanding of distributive generation will hamper the program.

Distributive generation can take many forms. In the IRP, BREC states that it is now encouraging distributive generation. But the form of distributive generation BREC envisions is simply not realistic for a low-cost, fully regulated utility. The BREC IRP encourages distributive generation that is utility dispatched and is only operated when wholesale rates exceed retail rates. BREC believes that interruptible customers might purchase distributive generation as a back-up for use when loads are interrupted. Under current market conditions, this form of generation would only operate at peak times. While this arrangement is attractive for BREC, it is not attractive for the customer who installs the generating capacity. Because of the need to repay the capital costs associated with adding the capacity, the customer will need to operate the distributive generation as much as possible, thus displacing retail rate power. If the distributive generation is operated only at peak times, it would be very difficult for the customer to recoup the investment in the generator.

The addition of 62 MW of Willamette distributive generation is much more realistic. Willamette will operate the generator as much as possible to repay the capital costs associated with the investment. BREC does not see this form of distributive generation as attractive, since it will create both a reduction in load (KW) and a corresponding reduction in energy sales (KWH). This is the more realistic form distributive generation will take. BREC must face the economic reality that with few exceptions, a customer is not going to make the capital investment in distributive generation only to refrain from use of that generation except during those limited times when BREC calls for it. If BREC want dispatchable peak generation, it will probably have to build that generation itself.

Though distributive generation will most likely be of the Willamette type rather than of the dispatchable peaking type envisioned in the IRP, BREC should pursue distributive generation. Loss of sales to the customer who adds distributive generation is made up for by new loads coming on to the system. If BREC can remain revenue neutral and can avoid having to build expensive new generation at the same time that a customer lowers its costs with distributive generation, a win-win situation is created for all parties. By comparison to the sellers-market driven high cost of gas-fired generation and the recent large increases in the cost of natural gas, distributive generation offers lower costs and less risk.

Like distributive generation, BREC's customer-based program of load management through interruptible tariffs offers significant benefits to both the utility and customer. Previously, BREC's large surplus of capacity made interruptible programs economically untenable and unattractive. Now, for the utility, the use of interruptible tariffs will be valuable in avoiding the need to build or procure expensive new generating capacity. At the same time, the program offers the customer a way to lower costs, and will, therefore, be attractive. Assuming participants emerge, BREC's potential shortage of capacity places it in the position of developing a strong interruptible program.

While BREC should be commended for its customer-based approaches to meeting new loads, the programs proposed have one common problem: all are oriented toward large customers. Though most of the three BREC Cooperative's members are residential and small business customers, none of the new customer-based programs include these members. Smaller customers can and should also be able to enjoy the benefits of distributive generation. Unfortunately, extensive regulations and the cost of special metering from the PURPA era stand in the way of small generation. Over half the states in the nation have some form of Net Metering to remove this barrier from small distributive generation. As stated in the informal conference, the devil is in the detail when dealing with issues like Net Metering. The Office of Attorney General encourages BREC and its member cooperatives to develop Net Metering tariffs that are beneficial to both BREC and the smaller cooperative members so all customers will have the opportunity to participate in BREC's new distributive generation program.

One troubling aspect of the IRP is the rejection of Strategic Conservation, conservation that reduces both KW and KWH. The effect of Strategic Conservation on BREC loads and sales would very similar to the effect of Willamette's distributive generation project. Strategic Conservation can help members lower their bills. It can also help BREC reduce future demand. This is a win-win situation. The 1999 BREC IRP rejected most Strategic Conservation based on a 1995 R.W. Beck study. This study was done when BREC had a surplus of generating capacity and no need to reduce load. Now that BREC must control load growth or deal with issues of procuring or building capacity to serve load growth, BREC should immediately set about securing a new study done to determine which conservation and load management programs are cost effective. Strategic Conservation is a customer-based program from which all customers, including small customers, would benefit. As BREC has chosen to use customer-based programs to control load growth, all customers, regardless of size, should be able to participate in and enjoy the benefits of these types of programs.

While the BREC IRP recommended a customer-based approach of controlling load growth, supply side options were also considered. Even though BREC does not need new capacity at this time, it is important to correct problems with the IRP now, before the need arises. The 1999 IRP did a poor job of examining renewable resource options which may be critical to meeting environmental requirements in the future. The BREC service territory sits adjacent to a number of Ohio River potential hydropower sites that could supply BREC with clean low-cost power. The IRP completely ignored this renewable option.

The IRP did include biomass as a renewable option for review. Unfortunately, the biomass option reviewed was an expensive theoretical plan that calls for growing trees on large plantations. A lower cost biomass option would be to use the massive amount of woodwaste available in or near the service territory that can be obtained at little or no cost. Unless BREC explores the lowest cost renewable options available, renewable resources will never appear to be cost effective, despite the fact that some options are competitive.

Respectfully Submitted,

Elizabeth E. Blackford
Assistant Attorney General
1024 Capital Center Drive
Frankfort, Kentucky 40601
(502) 696-5453

CERFICATE OF SERVICE AND NOTICE OF FILING

I hereby give notice that this the 2nd day of October, 2000, I have filed the original and ten copies of the foregoing with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601, and certify that this same day I have served the parties by mailing a true copy of same, postage prepaid to:

JOHN STAPLETON
633 TETON TRAIL
FRANKFORT KY 40601

HON IRIS SKIDMORE
HON RONALD P MILLS
OFFICE OF LEGAL SERVICES
FIFTH FLOOR
CAPITAL PLAZA TOWER
FRANKFORT KY 40061

DAVID SPAINHOWARD
VICE PRESIDENT BIG RIVERS ELECTRIC CORPORATION
P O BOX 24
HENDERSON KY 42420

HON JAMES M MILLER
SULLIVAN MOUNTJOY STAINBACK & MILLER PSC
100 ST ANN STREET
P O BOX 727
OWENSBORO KY 42302

HON DOUGLAS BERESFORD
HOGAN & HARTSON LLP
555 THIRTEENTH STREET N W
WASHINGTON D C 20004-1109

RECEIVED

OCT 2 2000

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC COPRPORATION) CASE NO. 99-429

* * * * * * * * * * * * * * *

KENTUCKY DIVISION OF ENERGY'S COMMENTS RELATED TO THE 1999 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION

Comes now the Kentucky Natural Resources and Environmental Protection Cabinet, Department for Natural Resources, Division of Energy (KDOE), and offers comments related to the 1999 Integrated Resource Plan of Big Rivers Electric Corporation. In addition, KDOE urges that the Commission reject Big Rivers' 1999 IRP and require it to be redone and resubmitted, within six months, in a manner that conforms to the provisions of 807 KAR 5:058; or, in the alternative, that the Commission require Big Rivers to submit its next scheduled IRP approximately twelve months from today's date and require that the new IRP conform to the provisions of 807 KAR 5:058.

I. Big Rivers' 1999 IRP does not provide for meeting future demand at the lowest possible cost for all customers.

The second sentence of the Necessity, Function, and Conformity section of the integrated resource planning (IRP) regulation, 807 KAR 5:058, states: "This administrative regulation prescribes rules for regular reporting and commission review of load forecasts and resource plans of the state's electric utilities to meet future demand with an adequate and reliable supply of electricity at the lowest possible cost for all customers within their service areas, and satisfy all related federal laws and regulations." Similarly, the first sentence of Section 8, Resource

Assessment and Acquisition Plan, states: "(1) 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."

It should be noted that the regulation uses the word "cost" and specifically does not call for a plan that keeps the utility's *rates* at the lowest possible level. A strategy that minimizes rates will differ in significant respects from a strategy that minimizes the total costs for all customers. The KDOE interprets the phrase, "at the lowest possible cost for all customers" to be functionally equivalent to a requirement to minimize the Total Resource Costs (TRC) of the Resource Assessment and Acquisition Plan. The text, *Demand-Side Management Planning*, describes the TRC test as "a measure of the total net resource expenditures of a DSM program from the point of view of the utility and its ratepayers as a whole...This test is also called the All Ratepayers test."[1] Further, "This test is a measure of the change in the *average cost of energy services* across all customers."[2] [emphasis in original] For this reason, KDOE holds that the TRC test, or All Ratepayers test, is the cost-effectiveness test that most closely reflects the intent of 807 KAR 5:058, and that it should be the primary criterion showing whether all ratepayers are being optimally served.

Big Rivers, through its consultant, Burns & McDonnell, has stated that it concurs with this position. In a data request, KDOE referred to the pertinent section of 807 KAR 5:058 and asked if Big Rivers would agree "that the primary criterion showing whether all ratepayers are being optimally served should be the TRC, or All Ratepayers test." The witness, Kiah Harris of

[1] Gellings, Clark W. and John H. Chamberlin, *Demand-Side Management Planning*, 1993, Fairmont Press, p. 260.
[2] *Ibid.*, p. 261.

Burns & McDonnell, wrote, "Yes, that is why the TRC was used to evaluate the options."[3] Mr. Harris repeated this position at the informal conference in Frankfort on 9/8/00.

During the informal conference, the KDOE representative, Geoffrey Young, raised the issue of whether Big Rivers and its consultant actually treated the TRC test as the primary criterion in practice when they developed the 1999 IRP. The following paragraphs contain statements that Burns & McDonnell has made about their use of various standard cost effectiveness tests.

In preparing the 1999 IRP, Burns & McDonnell "reviewed the R.W. Beck study and considered options which were viable at the time of the study. Given the industry's general trend toward lower capacity costs and commodity purchases and sales, Burns & McDonnell was able to eliminate several programs which were considered in 1995."[4] Similarly, "Burns & McDonnell reviewed those few programs found to be cost-effective in 1995, reviewed Big Rivers' current costs and situation and established that those marginally cost effective programs would fail to be cost effective in the current situation."[5]

KDOE has established that in this context, Burns & McDonnell equates the phrase "cost effective" with passing the Utility Cost Test.[6] At the informal conference, Mr. Young referred to this response and asked, "Reading this answer, one would expect to find that Burns & McDonnell reviewed the eleven programs identified by R.W. Beck in 1995, picked out the most cost-effective ones – that is, the ones with the highest Utility Cost Test ratios – and then found that those programs fail the Utility Cost Test when using the 1999 cost data. Would that be a reasonable expectation?" Mr. Harris answered, "Yes."

[3] Response to KDOE Item 5.g, 2nd set.
[4] Response to KDOE Item 14, 1st set.
[5] Response to KDOE Item 16.b, 1st set.
[6] Responses to KDOE Items 16.a and 17, 1st set.

In response to another question, Burns & McDonnell wrote, "Positive Participant and Utility cost tests, for instance, would benefit both the customers and the utility."[7] Mr. Young followed up at the informal hearing: "May I try to paraphrase this: A positive Participant Test benefits the customers; a positive Utility Cost Test benefits the utility; and if the results of both the Participant and the Utility Cost tests are positive, it would benefit both the customers and the utility – Is that what you're saying?" Mr. Harris answered, "Yes."

In response to another question, Burns & McDonnell commented, "Programs that are not cost-effective to the participant are immediately discarded (since they would be difficult to sell and impractical to fund by individual customers)."[8]

During the informal conference, Mr. Young distributed the following table, which was compiled from the *Centralized Coordinated DSM Planning Study*, prepared for Big Rivers by R.W. Beck in March, 1995. This study has been the basis for Big Rivers' decisions about which DSM programs to implement.[9]

Table 1
Big Rivers IRP Case No. 99-429
Cost-Effectiveness Results from 1995 DSM Study by R.W. Beck

DSM Program	Participant	Utility	RIM	TRC
1) Res Water Heater Tank Wrap	11.20	5.86-11.91	0.29-0.58	1.38
2) Res Water Heat – Showerheads	8.92	4.71-9.87	0.28-0.60	1.11
3) Res Setback Thermostat	16.91	4.10-8.56	0.13-1.09	2.02
4) Res Air Source Heat Pump	5.03	2.52-3.16	0.30-0.44	0.62
5) Res Water Heat Traps	19.36	10.39-22.09	0.28-0.63	2.45

[7] Response to KDOE Item 1.f, 2nd set.
[8] Response to KDOE Item 19.b, 1st set.
[9] Response to KDOE Item 5.f, 2nd set.

6) Res Water Heat Pipe Wrap	2.76	1.26-2.64	0.24-0.52	0.30
7) Ground Source Heat Pump	0.24	0.00	1.03-1.10	0.00
8) Air Source Heat Pump	0.03	0.00	0.99-3.63	0.00
9) Res Replace Water Heater	0.03	0.00	1.42-3.38	0.00
10) C/I Replace Water Heater	0.00	0.00	1.78-3.70	0.00
11) C/I Replace Heat Pump	0.15	0.00	0.75-1.06	0.00

The table lists the eleven centralized DSM programs analyzed in detail by R.W. Beck and their reported benefit/cost ratio results on the four standard (California) cost-effectiveness tests – the Participant Test, the Utility Cost Test, the Rate Impact Measure Test, and the Total Resource Cost Test.[10] [Note: The fifth Standard California test, the Societal Test, takes account of environmental and other external effects and is not always calculated.]

Mr. Young pointed out that the three DSM programs selected by Burns & McDonnell as being "viable," "cost effective," and worthy of further analysis when developing the 1999 IRP were Programs 7, 8, and 9.[11] These three programs had estimated Utility Cost Test results of zero, TRC Test results of zero, and extremely poor Participant Test ratios. According to Burns & McDonnell, these programs should have been "immediately discarded since they would be difficult to sell and impractical to fund by individual customers" (Participant Test ratio less than 1); but they were not. According to Burns & McDonnell, they should have been discarded because they fail to benefit the utility company and are not cost-effective (Utility Cost ratio less than 1); but they were not. And they should have been discarded because they fail to meet the acknowledged "primary criterion" for evaluating potential new programs, the TRC Test; but they were not. Other programs that passed the TRC, UC, and P tests in the 1995 study, however,

[10] R.W. Beck DSM study, 1995, pp. 75, 81, 87, 93, 99, 105, 111, 117, 123, 129, and 135.
[11] Response to KDOE Item 14, 1st set.

were discarded; they were not selected as "viable," "cost effective," or worthy of further analysis. There is a striking contradiction between the program selection criteria endorsed by Burns & McDonnell in answers to data requests and the consultants' actions in the process of developing the 1999 IRP.

At the informal conference Mr. Young asked whether it was possible that Burns & McDonnell did not really consider the TRC Test to be the primary criterion when assessing various resource options. He pointed out that the only cost effectiveness test in which Programs 7, 8 and 9 did well is the Rate Impact Measure (RIM Test). Conversely, the only cost effectiveness test that the discarded Programs 1, 2, 3 and 5 did *not* pass was the RIM Test. He asked if it was possible that Burns & McDonnell actually considered the RIM Test to be the primary criterion.

Mr. Harris responded by saying that Burns & McDonnell used the TRC Test as the primary criterion when selecting the load-shifting/interruptible rate programs that are recommended for implementation in the IRP. Many load-shifting/interruptible rate programs, however, pass the RIM Test as well as the TRC Test. For example, a residential load management program being newly developed by LG&E has an estimated TRC ratio of 2.90 and RIM ratio of 1.33, and a similar load management program for LG&E's commercial customers has an estimated TRC ratio of 1.95 and RIM ratio of 1.32. KDOE has stated that such load-shifting programs clearly benefit the utility and all customers – participants and non-participants – and should be implemented. Even if Burns & McDonnell did in fact use the TRC Test as the primary criterion when selecting the load-shifting/interruptible rate DSM programs, however, it is completely irrelevant unless the same criteria are applied to *all* DSM programs on an equal basis. Instead, what Burns & McDonnell has apparently done is discarded a very large class of

DSM programs on the grounds that they may exert an upward pressure on rates, and then made use of the TRC test (possibly in addition to the RIM Test) when assessing the small class of DSM programs that remained.

The effects of this analytical approach or strategy are far-reaching. Gellings and Chamberlin point out that when rates are higher than marginal costs, which is generally the case when a utility does not face capacity constraints, very few DSM programs pass the RIM Test.[12] The approach used by Big Rivers and its consultant – to discard all DSM programs that may exert upward pressure on rates, however slight – has the effect of eliminating a very large number of potential DSM programs that would lower both the revenue requirements of the utility (UC Test) and the total costs of the average customer (TRC Test). Any IRP based on this approach or strategy will necessarily fail to minimize the total cost of providing electricity services to all customers, and will necessarily fail to meet the provisions of 807 KAR 5:058.

A point raised by the Attorney General's Office (AG) casts doubt on the assumption that strategic conservation-type programs would even cause any upward pressure on rates. In Item 10 of its second set of questions, the AG notes, "Follow-up to PSC Item 5, page 7 of 9. This response states that strategic conservation will have a negative financial impact on Big Rivers and cause member rates to rise...(b) Big Rivers' response to the Attorney General's Request, Item 2, shows present and projected revenues from sales of surplus energy at a price above the 33.78 mils Big Rivers receives from member coops. Please explain why strategic conservation is not a win-win concept, since members can reduce their bills and Big Rivers can receive more revenues than it would selling this surplus energy to members (and reducing the need for new capacity also)." The written response by Mr. Harris of Burns and McDonnell stated only,

---

[12] Gellings and Chamberlin, *Op. cit.*, p. 277.

"Strategic conservation cannot be turned on and off in response to the pricing anomalies in the wholesale market."

While the response is factually correct, it is not an answer to the question. It explains only why strategic conservation programs are not as advantageous as load-shifting programs, not why strategic conservation is not a win-win concept. If the AG's premise in this question is correct – that Big Rivers can generally sell surplus energy off-system at a profit – then every objection raised against strategic conservation in the IRP and in responses to data requests evaporates. Rather than cause upward pressure on rates, strategic conservation would reliably free up more surplus capacity and cause downward pressure on rates, benefiting the utility company and all customers (non-participants as well as participants in DSM programs).

At the informal conference, representatives from Big Rivers raised other objections to strategic conservation, or in their terms, "passive DSM." One individual said that in contrast to the 62 MW of capacity made available by the planned Willamette cogeneration unit, "passive DSM" comes in numerous small bits and is therefore hard to predict or value precisely. He noted that Big Rivers has arranged for a contract for backup generation, which will convert the Willamette capacity to firm power that can be sold on the open market. Rather than identifying the drawbacks of strategic conservation, these arguments in fact highlight its advantages. On a statistical basis, strategic conservation functions reliably, year-round without interruption, reducing demand without requiring the expense or staff time involved in purchasing backup generation contracts. The same well-established techniques used to predict loads can be used to predict the overall system effects of the actions of thousands of customers. While a small number of customers may decide to replace their energy-efficient devices with inefficient ones, the large majority will not, and the overall trends can be modeled statistically.

Because the 1999 IRP prepared for Big Rivers by Burns & McDonnell rules out the serious consideration of a very large class of DSM programs, it fails to meet future demand at the lowest possible cost for all customers within the utility's service area, as required by 807 KAR 5:058.

II. Big Rivers' 1999 IRP does not assess potentially cost-effective improvements to and more efficient utilization of transmission or distribution facilities.

Section 8(2)(a) of 807 KAR 5:058 states, "The utility shall describe and discuss all options considered for inclusion in the plan including: (a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities." When KDOE requested information about distribution system planning, however, Big Rivers declined to provide cost analyses, stating that it "has no distribution system."[13] At the informal conference, Mr. Young followed up by establishing that Big Rivers is owned by its member cooperatives, which in turn operate distribution systems.

It is clear to KDOE that the intent of Section 8(2)(a) is to ensure that all reasonable options to reduce long-term utility costs are assessed, whether they are located within the generation, transmission, or distribution sector. The combined service areas of the member cooperatives served by Big Rivers have been treated as a single system for generation and transmission planning purposes, and there would appear to be no reason to exclude the distribution system from analysis simply because it is operated by different legal entities within the overall Big Rivers system.

At the informal conference, representatives of Big Rivers objected to the idea of coordinated distribution system planning, saying that it is not feasible for Big Rivers to "tell the

[13] Response to KDOE Item 6, 2nd set.

member cooperatives what to do in regard to their distribution systems." Coordinated least-cost planning, however, does not require Big Rivers to tell the member cooperatives what to do. What would be required is for Big Rivers to inform the member cooperatives about the requirements of Section 8(2)(a) and to establish a mechanism for sharing information about distribution system planning among Big Rivers and the member cooperatives. The pertinent section of the IRP could consist of nothing more elaborate than a compilation of the member cooperatives' analyses of options and least-cost distribution system plans. It would likely be more effective, however, if joint planning could be undertaken in a coordinated effort to identify potential synergies. In no case, however, would Big Rivers need to dictate the details of distribution system plans to its members.

The 1999 IRP likewise did not include an analysis of any options for improving the efficiency of the existing transmission system. KDOE became aware of the existence of a "Long Range Engineering Plan" that discusses planned upgrades to the transmission system only through a response to a data request.[14] KDOE believes that in order to comply with Section 8(2)(a), the IRP should have included the following elements:

1) either the transmission-related section of the Long Range Engineering Plan or a summary thereof;

2) a summary of changes made since the publication of the Long Range Engineering Plan;

3) an analysis of options for improving transmission system efficiency; and

4) a long-range least-cost plan for upgrading the transmission and distribution systems and improving their efficiency.

[14] Response to KDOE Item 21, 1st set.

Through certain of its data requests and during the informal conference, KDOE suggested that local integrated resource planning (LIRP) offers a promising approach for minimizing long-term transmission and distribution system costs and achieving the intent of Section 8(2)(a). Additional information about LIRP is included below in the section titled, "Additional Comments." KDOE also mailed copies of a detailed report on LIRP, which was the basis for these comments, to the parties involved in this case.

III. The 1995 DSM Planning Study was fundamentally flawed and cannot provide an adequate basis for DSM planning today.

During 1994 and early 1995, the consulting firm of R.W. Beck worked with staff at Big Rivers and its member cooperatives to do strategic planning and develop a DSM planning study.[15] Section 3 of the study describes the process by which the consultant and a DSM team at each member cooperative screened an initial list of 314 potential DSM programs, leaving a relatively small number to be analyzed in detail. The "comprehensive list" of 314 programs was not listed in the report. Although a citation was provided – Federal Register 40 CFR Subpart F, Appendix A – it appears to be missing the Part and Section numbers; KDOE was unable to use the citation to find the list.[16]

The list probably dates back to the early 1990s. Since that time, steady advances have been made in demand-side technology. New, energy-efficient technologies and whole-system design methods that have been developed in the intervening decade could alter the study's results.

The report states that the DSM teams used certain screening criteria and screening criteria weighting factors to reduce the list from 314 to 50 top-ranked technologies. The qualifications

[15] R.W. Beck, *Centralized Coordinated DSM Planning Study*, March 1995, p. 25.
[16] *Ibid.*, p. 32.

and experience of the members of the DSM teams from each member cooperative in screening, developing and analyzing DSM programs were not described. Although the criteria are not listed in the text, it is possible to infer from Figure 3-1 on page 33 that they were Utility Load Shape Objectives; Technology Applicability; Customer Acceptance; and Technical Viability/Maturity. Although these criteria are not explicitly defined and the criteria weighting factors are not provided, KDOE has identified serious problems with three of the four criteria used.

A. Utility Load Shape Objectives

The objection KDOE has to this criterion is that it serves as a qualitative proxy for the Rate Impact Measure (RIM) Test. If all other factors are held equal, a measure that better meets the utility's load shape objectives will score higher on the RIM test, and conversely. KDOE has consistently held that the RIM test should not be used to screen out DSM programs because supply-side options are not screened in the same way. To apply an additional, very stringent requirement to demand-side options biases the IRP process strongly in favor of the supply side, and defeats one of the key purposes of integrated resource planning. In addition, when the RIM test is used to compare DSM programs against each other, it introduces an unacceptable degree of bias in favor of load shifting programs and against programs that save energy. Because the load shape criterion has the same effect as the use of the RIM Test, KDOE considers it inappropriate. (KDOE is not claiming that Big Rivers or its consultant in 1995 intentionally selected this criterion in order to introduce the RIM Test covertly, but only that the criterion has the same effect as the RIM Test in practice.)

B. Technology Applicability

KDOE is unable to speculate about what this criterion might mean, and therefore cannot critique it.

C. Customer Acceptance

The problem with this criterion is that is it highly subjective. The reaction of customers to a DSM program is largely a function of the way the program is designed and administered. If the utility pays a higher fraction of the cost of installing a certain technology, for example, the cost to the customer will be correspondingly reduced and its acceptability will increase. Because customer acceptance depends so heavily on program design, it is not an inherent property of a technology and loses its usefulness as a way to screen alternatives. The rating of alternatives becomes highly dependent on the subjective feelings of the DSM teams' analysts about how customers might react to a DSM program that has not yet been designed at that stage in the screening process.

D. Technical Viability/Maturity

The main problem with this criterion is that the more mature a technology is, the closer it will be to standard practice. This criterion creates a strong bias against newer technologies and design methods that may have greater energy impacts when compared to what is presently being done. KDOE is concerned that the use of this criterion contributes to the selection of mediocre DSM programs instead of the best that could be implemented. In contrast, a market transformation approach would focus preferentially on relatively new technologies, combinations of technologies, or design methods which work, but which have not yet achieved widespread acceptance in the market. The market transformation approach will be considered in greater depth in the section below titled "Additional Comments."

R.W. Beck then performed what they called a "technical potential analysis" to screen out technologies that were judged to apply to a very limited market segment.[17] The consultant used the EPRI DSManager computer software to calculate the cost effectiveness of each program according to the five standard California tests. For reasons that are not explained, R.W. Beck focused on two of these tests, the TRC and the RIM Tests. These steps apparently reduced the list from 50 to 39 options.[18]

If our contention is correct that at least three of the four criteria used by R.W. Beck in its qualitative screening process had serious drawbacks, then there is no reason to think that the DSM programs selected for further consideration were the best alternatives available.

This hypothesis – that superior DSM program options were screened out and inferior options chosen for consideration – is supported by examining the list of 39 programs that made it through the qualitative and "technical potential" screening steps, shown in Exhibits 3-1 and 3-2 on pages 39-40 of the report. The list is dominated by residential retrofit programs. New residential construction does not appear, nor do commercial new construction, commercial daylighting, combined heat and power (C/I), industrial motor and drive systems, or industrial process improvements, all of which have been found to offer very large potential efficiency gains in other areas of the country (including the Pacific Northwest, which has electricity rates as low as Kentucky's). In addition, in view of our experience with other utility companies in Kentucky, KDOE questions whether the very poor cost effectiveness results on the TRC and RIM Tests reported for direct load control programs were calculated correctly. Such programs often either pass both the TRC and RIM Tests or come close.

[17] *Ibid.*, p. 35.
[18] *Ibid.*, pp. 39-40.

The study went on to group these programs in various ways and combined them into eleven selected "centralized" programs, listed in Table 4-1 (page 42). By this stage, all the industrial programs had been screened out. Five of the programs – Numbers 7 through 11 – were considered "RIM" programs, while Programs 1 to 6 were considered "TRC" programs. Although only the TRC and RIM Test results were reported in the text, the cost effectiveness test results for all five standard cost effectiveness tests can be found in Appendix B.

KDOE holds that at this point, the five "RIM" programs should have been discarded because of their poor performance on the Participant and Utility Cost Tests. Burns & McDonnell provided convincing reasons in their responses to certain data requests. According to Burns & McDonnell, "Programs that are not cost-effective to the participant are immediately discarded (since they would be difficult to sell and impractical to fund by individual customers)."[19] Further, programs that fail the Utility Cost Test are not "cost effective" and do not benefit the utility company.[20] All five of the "RIM" programs failed both the P and UC tests (as well as the TRC Test). One possible reason why R.W. Beck declined to include the P and UC Test results in the text of their study may have been to downplay the fact that five of their eleven selected programs failed both tests. It should be noted also that where R.W. Beck indicates "n/a" ("not applicable") in certain tables, the DSManager results provided in Appendix B actually showed TRC Test results that were zero or negative.[21]

After combining the selected programs in yet another way and tabulating the TRC and RIM Test results, the study moved directly to its conclusions and recommendations. Unfortunately, there are problems in this section as well. The first two conclusions appear to

[19] Response to KDOE Item 19.b, 1st set.
[20] Responses to KDOE Items 16.a and 17, 1st set, and informal conference on 9/8/00.
[21] R.W. Beck, 1995, Tables 5-1, 5-2, and 6-1.

contradict each other.[22] The first recommendation begins with the sentence, "The current wholesale rate structure does not provide accurate pricing signals based on Big Rivers current capacity situation."[23] KDOE is unable to find any discussion of or justification for this rather critical point in the body of the study. The long recommendation found in the middle of page 58, which is arguably the study's key recommendation, is extremely poorly written and unclear. The key sentence, "Based on Big Rivers current capacity situation and production costs, programs should not derive a benefit based on capacity or demand" is unclear and unsupported by discussion in the text. The final sentence of this recommendation has the effect of recommending against the implementation of all of the DSM programs analyzed, without clearly coming out and saying so.

In summary, the 1995 *Centralized Coordinated DSM Planning Study* by R.W. Beck contains the following fundamental flaws:

- The initial list of 314 DSM technologies was not provided. The list, which probably dates to the early 1990s, is outdated today.
- Three of the four qualitative criteria used to screen this list from 314 down to 50 technologies – Utility Load Shape Objectives, Customer Acceptance, and Technical Viability/Maturity – had serious problems. The remaining criterion, Technical Applicability, was not sufficiently defined to determine whether it had problems.
- Five of the eleven programs selected for further analysis should have been quickly screened out because they failed the Participant, Utility, and Total Resource Cost Tests.

[22] *Ibid.*, p. 56.
[23] *Ibid.*, p. 57.

- The final section contained conclusions and recommendations that were not supported by data or analysis in the study's text.
- Certain conclusions were mutually contradictory, and the study's central recommendation was written so confusingly as to be virtually opaque.

As detailed in Sections I through III above, KDOE holds that Big Rivers' 1999 IRP fails to meet the following provisions of 807 KAR 5:058:

- The IRP does not include an assessment of potentially cost-effective resource options covering improvements to and more efficient utilization of the transmission or distribution system;
- The 1995 DSM planning study upon which the 1999 IRP's analysis of demand-side resource options is based was fundamentally flawed and cannot provide an adequate basis for DSM planning today; and
- The strategy of preventing upward pressure on rates, however slight, has led Big Rivers and its consultant, Burns & McDonnell, to reject a very large class of potentially cost-effective DSM programs out of hand, making it impossible to conform to the basic intent of 807 KAR 5:058, i.e., to develop a plan that meets future demand at the lowest possible cost for all customers.

KDOE does not believe that Big Rivers' managers are intentionally choosing a strategy that is not in the best interest of its member cooperatives and their customers. Comments made by representatives of Big Rivers at the informal conference indicate that they sincerely believe that the interests of the customers and the utility company are best served when rates are kept at the lowest possible level. This, however, is a serious misconception. To implement certain types of DSM programs [also known as strategic conservation programs] that greatly benefit customers and reduce the utility's revenue requirements, it may sometimes be necessary to accept a certain amount of upward pressure on rates. Such strategic conservation programs can and should be combined with load-shifting programs that tend to reduce rates, yielding a relatively neutral rate impact overall.

At the informal conference, representatives of Big Rivers emphasized the fact that the utility is not a for-profit corporation but a cooperative. David Brown Kinloch, the consultant for the Attorney General's Office, noted that that fact should make it easier for Big Rivers to implement programs that benefit its customers by helping them reduce their energy bills. KDOE finds it ironic that the effect of Big Rivers' apparent IRP strategy – to prevent upward pressure on rates, however slight – has been to create a scenario of Utility *versus* Customers to a greater extent even than in the IRP cases of the investor-owned utilities in which KDOE has participated during the past year (AEP, Cinergy, and LG&E).

For the reasons enumerated in Sections I to III above, KDOE believes that the Commission should reject Big Rivers' 1999 IRP and require it to be redone and resubmitted, within six months, in a manner that conforms to the provisions of 807 KAR 5:058.

If the Commission chooses not to reject the IRP, KDOE proposes the following alternative: Big Rivers has stated its intention to request a deviation to delay the filing of its next IRP until approximately two and a half years from now. This represents an extensive time period during which the utility's planning would be guided by an IRP that, in KDOE's view, is seriously deficient. KDOE objects to the granting of such a long time extension, and urges that the Commission require Big Rivers to submit its next scheduled IRP approximately twelve months from today's date, and require that the new IRP conform to the provisions of 807 KAR 5:058.

IV. Additional Comments

KDOE wishes to do more than criticize and challenge the IRP that has been prepared for Big Rivers. KDOE would like to offer constructive suggestions in the areas of developing an effective IRP, helping Big Rivers position itself in preparation for a more competitive electric industry in the future, and developing new types of DSM programs that benefit all customers without requiring the utility to pay rebates on an ongoing basis.

A. An Alternative Approach to Integrated Resource Planning

Many utility companies begin their analysis of demand-side options with a long list of individual technologies. This was the approach taken by R.W. Beck in 1995. The next task is to screen the list qualitatively to reduce it to a more manageable number of options to analyze in more detail. This process, however, leads to a focus on individual technologies rather than whole systems such as buildings or manufacturing processes. It tends to overlook the complex ways in which technologies interact and affect the performance of the overall system.

Rather than starting with a long list of individual demand-side technologies, Big Rivers and/or its consultants might instead start by examining a number of major energy-using functions such as space cooling, lighting, shaft power, etc. They could use information sources such as E Source to obtain performance data about the most efficient technologies and design methods currently on the market within each functional area. The team might then outline DSM program ideas and strategies that could address the market barriers in each area that are preventing customers from adopting the most efficient available technologies and methods. If Big Rivers were to consider and analyze combinations of complementary technologies through a whole-system perspective, such an approach would mirror that taken by E Source in its *Technology Atlas* series and other publications. The primary criteria for narrowing down the options to a manageable number would be (a) the Total Resource Cost Test, (b) the size of the potential impact within Big Rivers' service area, and (c) the objective of developing a set of DSM "programs which are available, affordable, and useful to all customers" [Reference KRS 278.285 (1)(g)].

KDOE is available to work with Big Rivers and its consultants in the process of developing its future integrated resource plans.

B. Preparing for a More Competitive Energy Services Market

KDOE supports the increasing role of competitive markets and customer choice in the electric utility industry, because it believes that if the markets in energy services are properly structured, competitive forces will be unleashed that will give rise to truly phenomenal efficiency gains within the energy sector. The characteristics of a better-functioning market are described below.

Pricing signals would serve as the primary determinant for energy-related decisions. Customers would have, or could obtain, adequate information about the life-cycle costs and benefits of their purchasing and investment decisions. Customers would be less concerned about the price of each kWh of electricity than about the size of their energy bills and the net value that various competing packages of energy services could provide to their businesses or homes. Businesses would apply the same financial criteria (payback periods or return-on-investment "hurdle rates") to cost-reducing investments as they do to investments that promise to increase sales. In transactions involving multiple parties, accurate information about future energy costs would be reflected in negotiated contractual arrangements, so that those parties bearing the costs of energy upgrades would be compensated by those parties enjoying the benefits. Designers who take the extra time necessary to improve the efficiency and performance of their buildings would be compensated for their efforts by their clients. Financing would be available at market rates for cost-effective energy upgrades. A sufficient number of sellers would exist to create a competitive market for energy services. Electricity prices would approach marginal costs, which would change throughout the day and year because of generation, transmission, or distribution system constraints, thus passing price signals on to customers and other market participants. Government policies would monetize external environmental effects at societally efficient rates, or at least there would be a functioning market for "green power." There might be a functioning market in saved energy, or "negawatts,"[24] in Amory Lovins' phrase.

While we recognize that the scenario described above can never be realized in its entirety, we believe that public agencies should promote policies that support the functioning of markets under ideal competitive conditions to the extent possible.

In stark contrast to the idealized competitive market for energy services described above, present-day markets are riddled with barriers that prevent customers from obtaining the most economically advantageous energy services available to them. The potential efficiency gains that these market barriers prevent are very large, as illustrated by the following discussion focusing on the commercial building sector.

A 1992 Strategic Issues Paper produced by E Source posits that, "Well over half of the energy used to cool and ventilate buildings in countries like the United States can be saved by improvements that typically repay their cost within a few years." Other analyses have found comparable potential savings in lighting, drivepower, office equipment and other end-uses. The report continues, "To a theoretical economist, these are astounding statements: it is inconceivable that in a market economy, such large and profitable savings would remain untapped. But to a

---

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

practitioner who knows how buildings are created and run, it is not only conceivable but obvious."[25] The rest of the report provides a detailed examination of the process by which buildings are designed, built and operated, and how inefficiencies are introduced at every stage through practices which are typical in the commercial construction market. Most of the barriers result from split incentives, perverse incentives, lack of information, and lack of communication between the numerous parties involved. Although each market participant may be behaving rationally within his or her narrow area of responsibility, the overall result is a system that chronically undervalues energy efficiency. Some causes of the chronic market failure in the field of new commercial construction are listed below:

- Real estate developers and investors, who make early building decisions, discount energy-related issues heavily, focusing on minimizing construction time and cost.
- U.S. rules on taxes and depreciation exacerbate the focus on first cost.
- Developers have very little information about the efficiency gains that are possible.
- Financial institutions may reject innovative designs, fearing delays in approval by code officials.
- Commercial appraisers and securities rating agencies know little about energy and have no way to evaluate designers' projections of energy performance.
- Site planning decisions may be made by professionals with little knowledge of energy before an architect is even hired, despite the fact that "Just proper choice of architectural form, envelope, and orientation can often save upwards of a third of the building's energy at no extra cost – 44% in one recent California design."[26]
- Most architects do not know enough about mechanical systems design and do not work very closely with the HVAC professionals – especially during the earliest phases of design, when decisions have the largest impacts.
- Mechanical designers and equipment vendors have economic incentives to oversize systems.

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

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

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

- Most often, no single member of the design team has overall responsibility for the entire interactive system. Even if an interdisciplinary team approach is desired, each profession communicates using different terms and has different incentives, making cooperation difficult.

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

- Architects and designers often handle potential liability concerns by oversizing equipment, but the client is left with higher capital and operating costs.

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

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

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

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

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

- The actual performance of HVAC systems in the field is often never monitored directly. The lack of actual data makes it difficult to know how best to improve their operation.

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

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

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

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

Given this (non-exhaustive) list of barriers in the new commercial construction market, it should not be surprising when analysts reach the conclusion that huge gains in energy efficiency are technically feasible at very reasonable cost. The Environmental Energy Technologies Division of the Lawrence Berkeley National Laboratory estimates that:

> If only tune-ups and performance monitoring of existing buildings were performed, average energy use could be reduced by about 20%. If proven efficiency measures were applied when a building is retrofitted (usually about every 15 years), about 50% reduction could be attained. The full range of efficiency measures that can be designed and incorporated into new buildings could bring about an energy reduction of as much as 75%.[27]

Other estimates (for example, by E Source) are even higher. The fact that a long list of market barriers exists does not mean that they could never be overcome through carefully designed programs and policies.

Savings of a similar magnitude are obtainable in the residential sector as well. The U.S. Department of Energy's *Building America* program is applying whole-building principles to new home construction and reducing energy use by approximately 50%, at little or no additional cost to production builders in a range of climate zones.

The Rocky Mountain Institute describes a case study of what can be done in the residential sector by a utility company that is seriously interested in exploring the potential energy savings resulting from whole-system design. The Pacific Gas and Electric Company, as part of its Advanced Customer Technology Test (ACT^2) program, hired the Davis Energy Group to improve an initial design for a house that already met California's strict Title 24 energy code,

[27] Lawrence Berkeley National Laboratory, "Creating High-Performance Commercial Buildings," *EETD News*, Fall 1999, pp. 1-2.

which is supposed to include all efficiency measures that are worth buying from a societal perspective. The first step was to eliminate unnecessary corners that had added 23 feet (11%) of length to the outside walls. The designers then put the windows in the right places, used window frames that would transmit less heat, and invented an engineered wall that saved about 74% of the wood, reduced construction costs, and nearly doubled the insulation. A number of small improvements to the building envelope, windows, lights, major appliances, and hot-water system raised the total energy saving to 60% and increased the cost by nearly $1,900. At the same time, however, the thicker insulation and better windows eliminated any need for the $2,050 furnace and its associated ducts and equipment. Instead, on the coldest nights, a small amount of hot water from the 94%-efficient gas-fired water heater could be run through a radiant coil cast into the floor-slab. Finally, the designers eliminated the air conditioner by adding several more efficiency measures that had not previously appeared to have been cost-effective based on a conventional (measure-by-measure) analysis. The report concludes as follows:

> "Factoring out small electrical appliances (one-third of initial electricity usage), which offered many savings opportunities but would be brought along by the buyer rather than installed by the builder, the resulting final design would save about 80% of total energy or 79% for electricity alone: 78% for space heating, 79% for water heating, 80% for refrigeration, 66% for lighting, 100% for space cooling, and 92% for space cooling plus ventilation. If such construction techniques became generally practiced – so-called "mature-market cost" – then those savings would make the house, in a mature market, cost about $1,800 less to build and $1,600 less to maintain.
>
> "The measured savings, adjusted for some last-minute design changes requested by the homebuyer, agreed well with these predictions. The house proved very comfortable even in a severe hot spell. Since by law the Title 24 code is supposed to include all cost-effective measures, the Davis house may mean that this influential state standard has to be rewritten from scratch."[28]

[28] Rocky Mountain Institute, "Designing For Zero Cooling Equipment in a Hot Climate," 1999, www.naturalcapitalism.org/sitepages/pid27.asp

If Big Rivers were interested in applying this approach in Kentucky, it might be possible to develop marketable house designs that replace the central furnace by a water-heater based system – home builder Perry Bigelow has done so in the Chicago area – and downsize or eliminate the conventional air conditioning system.

Similar examples can be cited in the industrial sector. A major use of electricity in industry is to operate pumps for moving liquids around. The carpet company, Interface, was planning to build a new factory. One of the factory's processes required 14 pumps. A leading firm specializing in factory design sized the pumps to total 95 horsepower. An Interface engineer, Jan Schilham, however, took a fresh look and was able to come up with a design that was not only more efficient but cost *less* to build. The first change used larger pipes and smaller pumps, greatly reducing frictional losses. Second, Schilham laid out the pipes first and then the equipment, in the reverse order from standard practice, enabling him to use shorter and straighter pipe runs. The combination of these two approaches allowed for a system with only 7 horsepower of pumping capacity – a 92% decrease. The lower capital cost of the smaller pumps, motors, inverters, and associated electrical system more than compensated for the additional cost of larger diameter pipes. The payback period for the higher-efficiency system was instantaneous and its return on investment was infinite because it was cheaper than the inefficient design. However, "optimization" techniques in use throughout the industrial sector routinely ignore systemic effects such as these, focusing only on single-component or partial-system optimization.[29]

These examples illustrate an important point about whole-system design: It is frequently more cost-effective to save large amounts of energy than small amounts. It can make sense from

[29] Hawken et al., *Natural Capitalism*, pp. 116-117.

a whole-system perspective to make certain components *more* efficient than a component-by-component "optimization" approach would suggest. This surprising phenomenon, called "tunneling through the cost barrier," results from capital cost reductions (e.g., smaller or no HVAC systems, smaller pumps) that can be added to the energy savings. "Optimizing components in isolation tends to pessimize the whole system."[30]

In conclusion, the market barriers to efficient design in all sectors of the economy – residential, commercial, and industrial – are large and long-standing. They can, however, be addressed and overcome through well-focused programs that involve a range of participants, including the utility company. We will describe a number of such "market transformation" concepts in Section C below.

C. Market Transformation – A New Approach to DSM

In anticipation of electric industry restructuring, many utility companies (including companies operating in Kentucky) have scaled back their traditional DSM programs, which often depended on paying rebates to customers to install more energy-efficient devices. At the same time, the concept of market transformation has been developed to provide an alternative to rebate-centered programs.

In this section, we will suggest an alternative approach to meeting customers' needs for energy services that Big Rivers and its member cooperatives may wish to consider. KDOE believes that this approach will offer significant profitable long-term opportunities for the utility as well as tangible economic benefits for customers.

It has long been a truism that customers do not need or desire energy or electricity per se, but rather the services – warmth, light, hot water, cooling, drive power – that it provides for

[30] *Ibid.*, p.117.

them. An economically rational customer will seek to maximize the net value of energy services purchased (i.e., the value added by the energy services minus the energy bill). An energy company that helps its customers maximize this value should enjoy a large market demand for its services.

Is it realistic to think that a company that sells a commodity can change its approach to one of helping its customers maximize value, even when it might result in less of the commodity being sold? The book *Natural Capitalism*, by Paul Hawken, Amory Lovins, and Hunter Lovins, describes several companies that are making the transition. Carrier, the world's largest manufacturer of air conditioning equipment, is now offering a "comfort lease" that ensures a certain indoor temperature during hot weather. Carrier can choose from a range of means to deliver the comfort: by doing lighting retrofits, installing high-performance windows, or installing its air conditioning equipment. "The less equipment Carrier has to install to deliver comfort, the more money Carrier makes. If Carrier retrofits a building so it no longer needs a lot, or even any, of its air conditioning capacity, Carrier can remove those modules and reinstall them elsewhere."[31]

The same concept is prevalent overseas:

> Ten million buildings in metropolitan France have long been heated by *chauffagistes*; in 1995, 160 firms in this business employed 28,000 professionals. Rather than selling raw energy in the form of oil, gas, or electricity – none of which is what the customer really wants, namely warmth – these firms contract to keep a client's floorspace within a certain temperature range during certain hours at a certain cost. The rate is normally set to be somewhat below that of traditional heating methods like oil furnaces; *how* it's achieved is the contractors' business. They can convert your furnace to gas, make your heating system more efficient, or even insulate your building. They're paid for results – warmth – not for how they do it or how much of what inputs they use to do it. The less energy and materials they use – the more

[31] Hawken et al., *Natural Capitalism*, Rocky Mountain Institute, Snowmass, Colorado, 1999, p.135.

efficient they are – the more money they make. Competition between *chauffagistes* pushes down the market price of that "warmth service." Some major utilities, chiefly in Europe, provide heating on a similar basis, and some, like Sweden's Goteborg Energi, have recently made it the centerpiece of their growth strategy.[32]

Other examples:

- "Some utilities and third parties have been offering 'torque services' that turn the shafts of your factory or pumping station for a set fee; the more efficiently they do so, the more they can earn."[33]

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

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

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

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

- Interface in Atlanta leases floor-covering services rather than selling carpet. Interface is responsible for keeping it clean and fresh, replaces parts of it when indicated by monthly inspections, and reduces overall life-cycle costs. Interface has also developed a new polymeric floor covering material, called Solenium, that combines many of the performance advantages of carpet and hard flooring and can replace carpet altogether.[34]

In each case, the firms providing the service may sell somewhat less of their commodity or product, but are able to meet the customer's actual needs in a more efficient way. They are paid for results – providing value to the customer – rather than for the quantity of inputs. The incentives of the service provider and the customer are no longer at odds; both parties are

[32] *Ibid.*
[33] *Ibid.*, p.136.
[34] *Ibid.*, pp. 137-141.

interested in performing the needed function in the most efficient way possible. This concept may represent a cutting-edge trend in our economy.

If Big Rivers and its member cooperatives were to focus more directly on becoming a provider of cost-effective energy services, they would initiate a number of programs and actions aimed at optimizing overall efficiency throughout the energy sector. Some of these initiatives would have immediate potential to improve the utility's financial condition, while others would help transform energy markets so that customers would value more highly, and demand, the kinds of services the cooperative could provide. The longer-term initiatives would also help establish Big Rivers' image in the market as consistently efficiency-oriented and dedicated to providing maximum value to its customers.

In the following sections, we suggest a number of initiatives that we believe should be investigated for possible implementation.

(1) Use Local Integrated Resource Planning (LIRP)

The method of local integrated resource planning, as described in a 1995 strategic issues paper by E Source, is designed to determine if costs could be reduced by deferring transmission and distribution upgrades through the use of geographically-focused demand-side programs.[35] The E Source paper provides case studies illustrating how a number of utilities have used LIRP to forestall costly T&D upgrades. Targeted projects identified through the use of LIRP demonstrate its value both in rural areas with widely dispersed customers and in congested urban centers.

[35] E Source, "Local Integrated Resource Planning: A New Tool for a Competitive Era," Boulder, Colorado, 1995.

In 1993, Ontario Hydro planners were facing rapidly-growing demand in the congested Collingwood area and projected a T&D upgrade costing C$83 million. After conducting a LIRP analysis, they developed a strategy that combined load-shifting residential water heaters, improving lighting efficiency, scheduling the operation of industrial furnaces, and making much smaller T&D upgrades, for a total cost of C$24.3 million, which included the cost of analyzing and administering the alternative strategy. Similar results were obtained in numerous other locations. Overall, Ontario Hydro credits LIRP with deferring some C$1.7 billion in T&D investments through September, 1995. LIRP has become the standard method of planning customer service and T&D planning. In the words of one distribution planner, "LIRP has become our business."[36]

The New York State Electric and Gas Corporation was able to avoid a $6.5 million T&D upgrade by providing an interruptible service rate to one large user and contracting to dispatch the user's two 300-kW backup generators, all at a hardware cost of $45,000.[37]

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

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

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

[36] E Source, 1995, pp. 6-8.
[37] Ibid., p.10.

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

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

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

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

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

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

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

- *Leads to better utilization of generating assets.* Peak clipping options (storage and generation) would result in higher utilization of baseload generators. Smaller generating units also can lead to smaller reserve capacity requirements, and distributed generation can cut grid losses."[38]

2) Initiate a Comprehensive Market Transformation Program in the New Commercial Construction Sector

To overcome the litany of chronic market barriers to energy-efficient new construction outlined in Section B above, a multi-pronged approach is advisable. The magnitude of the potential savings can be estimated by performing a technical potential study or by comparing the efficiency of typical new buildings being constructed today with state-of-the-art buildings in other jurisdictions. An excellent way to start the analysis of the technical potential would be to study the E Source Technology Atlas Series, which includes the following titles: ***Commercial Space Cooling and Air Handling***; ***Lighting***; ***Drivepower***; ***Space Heating***; and ***Residential Appliances.*** A key theme found over and over throughout these highly detailed, thoroughly-documented works is that there are major efficiencies to be gained through the whole-system integration of properly-sized technologies. Initial costs can frequently be held constant or even reduced through careful, whole-system design. KDOE's information requests relating to the amount of new construction occurring in Big Rivers' service area were intended to see if the utility had made any preliminary estimates of the size of the technical potential for efficiency improvements in the buildings sector.[39]

[38] Ibid., pp. 22-23.
[39] Responses to KDOE Items 10 and 11, 1st set.

Indirect but very real economic benefits resulting from improved daylighting designs such as increased retail sales[40] or improvement in the performance of students or workers[41,42] can make TRC benefit/cost ratios extremely high. For example, while the energy savings generated by the daylight-oriented whole-building design of Lockheed's 600,000 square foot office building in Sunnyvale, California paid back the initial extra costs in four years, absenteeism among a known population of workers dropped by 15%, which represents annual cost savings equal to the entire incremental cost of the improved design. To this could be added productivity gains estimated at another 15%, bringing the simple payback period down to a matter of weeks.[43]

There are several ways Big Rivers could enter the market for energy-efficient design services. One way would be to establish a (non-regulated) architectural/design firm, or form a non-regulated joint venture with one or more existing firms with experience in designing highly-efficient buildings. Another would be to initiate a program providing training, design incentives, and awards for energy-efficient architects, engineers, and HVAC system designers. A non-regulated joint venture with a manufacturer of energy-efficient modular or mobile homes would be another possible way to share in the efficiency gains available in new residential construction.

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

---

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

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

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

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

engineers, electrical engineers, lighting designers, building owners, facility managers, and facility engineers. Its goal is to train professionals and create a sustainable market demand for energy-efficient design and products. It applies a whole-building approach aimed at optimizing owner value, user comfort, and energy efficiency.[44] A recent study concluded that the PEC is effectively reaching its intended audience and is causing long-lasting behavioral changes that lead to more energy-efficient buildings.[45]

A multi-pronged program aimed at transforming the market for energy-efficient new commercial buildings would encompass training and technical assistance for the numerous parties involved in design, construction, and financing within this market sector. It could include an awards program to recognize and reward the parties involved in producing and operating highly efficient new buildings. Big Rivers could work with building code officials to "raise the floor" of allowable performance, thus complementing the awards program that affects the high-performance end. The company could help promote the use of energy lease agreements to reduce the problem of split incentives between commercial landlords and tenants.[46]

Another way to impact the low-efficiency end of the market would be to invert the hookup fee policy that is now in effect so that energy-efficient new buildings would be charged a low fee, or even would receive a rebate for hooking up to the grid, while energy sieves would be charged a much higher fee to cover some of the additional costs of distributing power to an inefficient building over its lifetime. If the fee differential were set high enough, such a policy would affect a building's initial costs, which would get the immediate attention of a segment of the market that might not otherwise respond to information about energy efficiency.

[44] Pacific Energy Center web site.
[45] Reed, John H. and Nicholas P. Hall, "PG&E Energy Center Market Effects Study," TecMRKT Works, Arlington, Virginia, May, 1998.

3) Promote Cogeneration and Other Distributed Generation

Big Rivers is presently working with one industrial customer who wishes to install a cogeneration system. At the informal conference, Big Rivers representatives stated that they would analyze future proposed cogeneration projects on a case-by-case basis. Central power plants are on the order of 33% efficient, with the remaining two-thirds or so of the fuel energy converted to waste heat. As noted by Thomas Casten of Trigen Energy Corporation, however, combined heat and power systems can make beneficial use of approximately 90% of the energy content of the fuel.[47] A firm seeking to optimize the efficiency of the energy sector as a whole would develop programs to enable customers with sizeable thermal loads to put this vast amount of wasted energy to use, and would develop shared savings arrangements to enable both parties to benefit from the increase in system efficiency.

Some analysts believe that the electric industry of the future will make much greater use of small-scale, distributed generation units, and that such a trend would fit well with the needs of more competitive industry.[48] Distributed resources "could be applied at or near customer sites to manage multiple energy needs and to meet increasingly rigorous requirements for power quality and reliability. Distributed generators could also be deployed at utility sites – for example, at substations for transmission and distribution grid support. Some experts predict that 20% or more of all new generating capacity built in the United States over the next 10 to 12 years could be for distributed applications. . .."[49]

---

[46] Alliance to Save Energy, "Guidelines for Energy Efficient Commercial Leasing Practices," Washington, DC, 1992.

[47] Casten, Thomas R. and Mark C. Hall, "Barriers to Deploying More Efficient Electrical Generation and Combined Heat and Power Plants," Trigen Energy Corp., revised March, 2000, Section 2.2.

[48] Moore, Taylor, "Emerging Markets for Distributed Resources," *EPRI Journal*, March/April, 1998, pp. 8-17.

[49] *Ibid.*, pp. 9-10.

In an effort to promote cost-effective distributed generation and renewable energy technologies, approximately thirty states have instituted "net metering."[50] Net metering laws (enacted by legislatures) or orders (instituted by public utility commissions) require electric utilities to purchase excess power from small-scale, renewable sources at the same retail rate they charge those customers. In effect, the owner of a small photovoltaic system can "run the meter backwards" when the system is producing more power than needed. Net metering policies usually set an upper limit on the size of the systems that are covered, and usually prohibit the utility from erecting other barriers such as unreasonably burdensome interconnect and safety requirements.

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

The Rocky Mountain Institute has performed detailed research on the question of the value of distributed generation to utility companies. They conclude that "Properly counting approximately 75 documented and measurable diseconomies of scale, not just the few well-known economies of scale, will typically make decentralized ways to make, store, or save electricity around ten times more valuable than conventionally scale-blind comparisons had long shown."[51] If their analysis is even close to correct, it suggests that Big Rivers and its member

[50] Starrs, Thomas J., "Summary of State Net Metering Programs (Current)," updated September, 1999.
[51] Rocky Mountain Institute, "Scale in Power Systems," 1999, www.naturalcapitalism.org/sitepages/pid27.asp

cooperatives may be able to garner substantial economic benefits from distributed generation technologies that may now be overlooked because of outmoded analytical methods.

4) Support Statewide and Regional Market Transformation Initiatives

The term "market transformation" refers to a set of planned interventions in the market that lead to longer-lasting impacts than traditional utility-sponsored DSM programs that depend on ongoing rebates for their effectiveness.[52,53]

The participation of Big Rivers in market transformation activities could help the cooperative establish its image in the market as experts in energy efficiency, and as being dedicated to maximizing the value that customers receive from the energy they purchase.

Regional market transformation alliances have been established in California, the Northwest, the Northeast, and the Midwest. Efforts typically involve a wide range of participants, and may include utilities, energy users, manufacturers, vendors, engineers, architects, construction firms, developers, building code officials, building owner associations, real estate professionals, lending institutions, federal agencies such as the U.S. Department of Energy and U.S. Environmental Protection Agency, state energy offices, and other parties.[54]

Kentucky companies and other interested organizations would be eligible to join the Midwest Energy Efficiency Alliance (MEEA). The mission of MEEA is "to work as a regional network of organizations to develop, design and implement energy efficiency and renewable energy resources in the rapidly-changing Midwest energy markets. The goals are to increase

[52] Meyers, Edward M., Stephen M. Hastie, and Grace M. Hu, "Using Market Transformation to Achieve Energy Efficiency: The Next Steps," *Electricity Journal*, May, 1997, pp. 34-41.
[53] Hall, Nick and John Reed, "Market Transformation: Expectations vs. Reality," *Home Energy*, July/August, 1999, pp. 16-20.
[54] Meyers et al., op. cit., p. 40.

public value, improve environmental quality, lower energy costs, and promote sustainable economic development."[55]

The Northwest Energy Efficiency Alliance, founded in 1997, has already reduced regional demand by 16 MW through market transformation initiatives related to compact fluorescent light bulbs, residential clothes washers, and semiconductor manufacturing process improvements.[56] The California Board for Energy Efficiency administers a variety of market transformation programs, including increasing the use of performance contracting with energy service companies, work with lighting manufacturers and distributors to bring energy-efficient lighting products to the market, home duct system improvements, and design tools for commercial architects and engineers.[57] Northeast Energy Efficiency Partnerships, Inc., has started market transformation programs in diverse areas including residential appliances, energy codes, high-efficiency motors, and commercial lighting design.[58]

5) Launch or Participate in a Kentucky Design Initiative

The foregoing discussion has emphasized the large potential efficiency gains that can be made through improved design of energy systems. RMI quotes the following example provided by senior mechanical engineer Eng Lock Lee:

> A typical colleague may specify nearly $3 million worth of heating, ventilating, and air-conditioning (HVAC) equipment every year – enough to raise a utility's summer peak load by a megawatt. Producing and delivering that extra megawatt conventionally requires the utility to invest several million dollars in infrastructure. If better engineering education were ultimately responsible for the equipment's being made 20-50 percent more efficient (a reasonably attainable and usually conservative goal), then over a 30-year engineering career, the utility would avoid

[55] Midwest Energy Efficiency Alliance web page, updated 2/23/00.
[56] Northwest Energy Efficiency Alliance, "Northwest Utilities to Invest $100 Million in Energy Efficiency through a Regional Alliance," press release, March 17, 2000.
[57] California Board for Energy Efficiency, "About the CBEE," web page updated 9/15/99.
[58] Northeast Energy Efficiency Partnerships Initiatives web page.

> about $6-15 million in present-valued investments *per brain*, without taking into account any of the savings in operating energy or pollution. This returns at least a hundred to a thousand times the extra cost of that better education. The savings would cost even less if good practitioners disseminated their improved practices through professional discourse, mentoring, or competition, so that educating just one engineer could influence many more."[59]

A company dedicated to providing optimum value to the purchasers of its energy services should be keenly interested in improving the quality of energy system design and engineering. The design of better industrial processes is particularly important. A comprehensive market transformation strategy cannot afford to overlook this high-leverage activity, and could use strategies such as awards, seminars, scholarships, and on-the-job training to encourage better whole-system design.

The discussion above was intended to illustrate some of the ways that KDOE believes energy efficiency can be enhanced significantly in every sector of the economy in the long term. Achieving these potential efficiency gains will involve numerous parties in addition to the utility company, and it will require the development of imaginative, market-oriented strategies over a sustained period of time. While the task is not wholly the responsibility of the utility, KDOE believes the utility still has an important role to play. The benefits to customers, Big Rivers, and society as a whole will make intensified efforts in this area more than worthwhile.

The market transformation approach can be used regardless of which regulatory framework is in place in Kentucky. KDOE hopes that Big Rivers will seriously consider market-transforming initiatives such as those outlined above, and will work toward the development of a variety of ways to improve end-use efficiency within Kentucky's energy sector while at the

---

[59] Hawken et al., *Natural Capitalism.*, pp. 111-112.

same time enhancing customer loyalty and strengthening the cooperative's financial condition in the long run.

VERIFICATION

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

Geoffrey M. Young

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

Subscribed and sworn to before me by Geoffrey M. Young, this the 2nd day of October, 2000.

Jean A. Cook

NOTARY PUBLIC

My Commission Expires: 1/10/2002.

Respectfully submitted,

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

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION CABINET

CERTIFICATE OF SERVICE

I hereby certify that on the 2nd day of October, 2000 a true and accurate copy of the foregoing KENTUCKY DIVISION OF ENERGY'S COMMENTS RELATED TO THE 1999 INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC COPRPORATION was mailed, postage pre-paid, to the following:

David A. Spainhoward, Vice President
Big Rivers Electric Corporation
P. O. Box 24
Henderson, KY 42419-0024

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

Hon. James M. Miller
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
P.O. Box 727
Owensboro, KY 42302-0727

Hon. Douglas Beresford
HOGAN & HARTSON L.L.P.
555 Thirteenth Street, N.W.
Washington, DC. 20004-1109

Iris Skidmore

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

Ronald M. Sullivan
Jesse T. Mountjoy
Frank Stainback
James M. Miller
Michael A. Fiorella
William R. Dexter
Allen W. Holbrook
R. Michael Sullivan
P. Marcum Willis
Anne H. Shelburne
Bryan R. Reynolds
Mark G. Luckett

September 20, 2000

RECEIVED
SEP 22 2000
PUBLIC SERVICE COMMISSION

Via Facsimile Transmission and Regular Mail

Thomas M. Dorman
Executive Director
Public Service Commission
211 Sower Boulevard, P.O. Box 615
Frankfort, Kentucky 40602-0615

Re: The Integrated Resource Plan of Big Rivers Electric Corporation, PSC Case No. 99-429

Dear Mr. Dorman:

Big Rivers Electric Corporation ("Big Rivers") has reviewed the September 11, 2000, Staff Memorandum regarding the September 8, 2000, informal conference in this matter. Big Rivers believes the memorandum fairly summarizes the proceedings in the informal conference, and has no suggestions for corrections or additions to the memorandum.

I certify that a copy of this letter has been served on the parties of record by mailing a copy of same to them, on this date, postage prepaid.

Sincerely yours,

Jim Miller

James M. Miller by Mark Willis

JMM/ej

cc: Service List
David Spainhoward

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

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

SERVICE LIST
CASE NO. 99-429

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

Office of the Attorney General of the Commonwealth of Kentucky

John Stapleton
Director of Energy
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Hon. Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Counsel for Natural Resources and Enviromental Protection

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Thomas M. Dorman
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602-0615
www.psc.state.ky.us
(502) 564-3940
Fax (502) 564-3460

Martin J. Huelsmann
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

September 13, 2000

Mr. David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P.O. Box 24
Henderson, KY 42419-0024

Mr. James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback &
Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, KY 42302-0727

Mr. Geoff Young
Division of Energy
663 Teton Trail
Frankfort, KY 40601

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

Ms. Iris Skidmore
Mr. Ronald P. Mills
Counsel for Natural Resources
And Environmental Protection
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Mr. Douglas Beresford
Counsel for Big Rivers Electric
Long, Aldridge & Norman
Suite 600
701 Pennsylvania Avenue
Washington, D.C. 20004

RE: Case No. 99-429
Big Rivers Electric Corporation

Dear Madams and Sirs:

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

Sincerely,

Thomas M. Dorman
Executive Director

Enclosure

INTRA-AGENCY MEMORANDUM

KENTUCKY PUBLIC SERVICE COMMISSION

TO: Case File No. 99-429

FROM: Jack Kaninberg

DATE: September 11, 2000

RE: Informal Conference of September 8, 2000
Regarding the Big Rivers 1999
Integrated Resource Plan Filing

On September 8, 2000, an informal conference was held at the Commission's offices in Frankfort, Kentucky for the purpose of discussing issues related to the Big Rivers Electric Corporation's 1999 Integrated Resource Plan ("IRP"). The parties represented at the conference were Big Rivers, the Office of the Attorney General ("AG"), the Natural Resources and Environmental Protection Cabinet's Division of Energy ("NREPC") and the Commission Staff. A list of the attendees is attached to this memorandum.

Big Rivers began by noting that it is a cooperative and not an investor-owned utility, and that there is a huge distinction between the two organizational types. It also noted that parts of its 1999 IRP were confidential, and that NREPC had not yet signed a confidentiality agreement, which was subsequently done.

NREPC had an extensive list of questions and issues relative to the Big Rivers IRP. Among these issues were the following:

- Distributed generation – NREPC inquired as to how Big Rivers defines distributed generation ("DG"), what Big Rivers had done to encourage the Willamette cogeneration facility, and whether there is a difference between the Willamette facility and strategic conservation. Relative to Big Rivers' definition of DG, there was a general dialogue about the reasons for Willamette's pursuit of cogeneration, with the AG noting that the capital cost of most DG is such that it needs to run continuously, as opposed to peak periods only, in order to pay off the capital costs. Big Rivers agreed that it was fair to distinguish between peaking DG and constantly-operated DG. Relative to encouraging DG, Big Rivers indicated that it tried to assist Willamette by answering questions and obtaining information. In response to a question regarding whether Big Rivers would view another such facility as beneficial, Big Rivers indicated that it would want to meet with the hypothetical owner, do an economic evaluation and protect the interests of its members. Big Rivers noted that, under current (wholesale market) conditions, it could go off-system with the proposed Willamette power, but that there is rate pressure from the reduction of load by Willamette. In response to the issue of Willamette power vs. strategic conservation, and why Big Rivers would encourage the former but not the latter, Big Rivers responded that the Willamette discussions are still ongoing, and that they are negotiating for the power as a marketable commodity, but that strategic conservation is piecemeal and hence not marketable. Big Rivers also indicated that reducing kwh (i.e., energy) is not in the members' best interests, but reducing kw (demand) is. In response, the AG argued that conservation in the past made no sense for Big Rivers because of its excess capacity situation, but that it makes more sense in the future, especially for a cooperative, in order to avoid the future cost of a peaking unit addition.

- Net metering – NREPC asked whether Big Rivers would object to potential legislation on net metering. Big Rivers responded that "the devil is in the details" of any such legislation; that it wouldn't be opposed to buying back power from members, but not necessarily at the member's cost; and that Big Rivers monitors DG developments, but it doesn't know what DG will succeed, or when.

- Technical Potential Study – NREPC commented that it does not believe that Big Rivers has done a sufficient study of the technical potential for conservation on its system.

- Local Integrated Resource Planning – NREPC argued that Big Rivers should consider distribution expenditures in determining the least-cost needs of members. While Big Rivers indicated that it signs off on its member cooperatives' long-term plans as least-cost plans to meet members' needs, it also suggested that a generation and transmission cooperative shouldn't dictate to member distribution systems how to distribute electricity. Relative to Local Integrated Resource Planning ("LIRP"), Big Rivers indicated that it was unable to obtain much information about LIRP. In response, NREPC agreed to send such information to Big Rivers, and to also provide copies to the AG and Staff.

- DSM cost-effectiveness tests – NREPC provided two handouts (attached) showing the 1995 study results of cost-effectiveness scores for eleven potential DSM programs. NREPC argued that those results suggested that Big Rivers considers the Ratepayer Impact Measurement ("RIM") test rather than the Total Resource Cost ("TRC") test to be the primary determinant for further consideration of DSM programs. Big Rivers maintained that the programs it has developed to meet peaking requirements, such as interruptible rates, were done on a TRC basis.

NREPC summarized its comments by noting that the Big Rivers is the first cooperative whose IRP it has reviewed; that Big Rivers seems to focus on the effects on rates for DSM nonparticipants; that small rate increases aren't necessarily "the worst possible outcome"; and that, in the opinion of NREPC, the Big Rivers IRP fails to meet applicable regulations.

The AG began by noting Big Rivers' planned payoff of its RUS note by April of 2022, and noted discrepancies between Big Rivers' actual margins versus its IRP margins. Upon being told that Big Rivers was conservative in its financial forecasts, the AG agreed that the numbers appeared to be achievable. The AG also concurred that Big Rivers' emphasis on load reductions rather than gas-fired capacity seems justified in light of recent increases in natural gas costs. Next, the AG asked whether Big Rivers has contingency plans if its future load growth doesn't slow, and suggested that there may be pent-up demand in addition to an improved economy in Big Rivers' service area. In response, Big Rivers noted that a survey of industrial customers indicated that growth was "pretty much fixed" for those customers, and that going-forward growth is expected to be "rural" in nature. The AG also questioned whether Big Rivers has evaluated biomass (i.e. wood waste) as a "free local resource". Big Rivers responded by noting that Western Kentucky Energy Corporation, which operates the generation assets previously owned by Big Rivers, has a grant to evaluate the conversion of chicken manure to gas. The AG concluded by suggesting that Big Rivers tends to be oriented towards its industrial customers, and that therefore there is not much conservation emphasis on the residential customers who are the majority of its (ultimate) membership.

Commission Staff asked a few questions to update and clarify previously-filed information. In response to a question regarding the recently-adopted Rate Schedule 10, Big Rivers indicated that a new coal mine will qualify for it. Relative to environmental compliance, Big Rivers indicated that review of compliance alternatives for nitrous oxides was continuing; that a U.S. Court of Appeals ruling extending the compliance deadline until 2004 was generally advantageous; and that an original compliance estimate of $30 million remains unchanged. Relative to the 62 MW Willamette cogeneration facility, Big Rivers updated the situation by noting that the contract negotiation process is very fluid at this point; that the plant's proposed in-service date remains the same; and that Willamette is trying to get expedited delivery of the unit. Relative its capacity situation in the next few years, Big Rivers indicated that it will soon ask for Board approval to execute an agreement to market 20 MW of capacity and energy for 2001 and 2002. Finally, relative to its plans to request a deviation to delay the filing of its next IRP, Big Rivers indicated its willingness to informally discuss a mutually agreeable timeframe for scheduling that filing.

The Informal Conference concluded with a reminder that the Intervenors' written comments were due to be filed by October 2, 2000, and Big Rivers' reply comments were due by October 27, 2000.

Big Rivers Informal Conference
Case No. 99-429

Name	Organization
JACK KANINBERG	KPSC
Betsy Blackford	OAG
Geoffrey Young	Ky Div. of Energy
Jim MILLER	SULLIVAN MOUNTJOY STAINBACK & MILLER FOR BIG RIVERS
Iris Skidmore	NREPC - Office of Legal Services
Hugh Archer	Comm Office, Dept for Natural Resources
RUSS POGUE	BIG RIVERS
Bill Blackburn	" "
MIKE CORE	" "
Mark Hite	" "
TRAVIS D. HOUSLEY	" "
BILL YEARY	" "
KIAH HARRIS	Burns & McDonnell
David Spainhoward	Big Rivers
RICHARD RAFF	PSC - LEGAL
Daryl Newby	PSC - Fin. Analyses
David Brown Kinloch	OAG
JEFF SHAW	PSC - FINANCIAL ANALYSIS

DOE- 6

Big Rivers IRP Case No. 99-429

Cost-Effectiveness Results from 1995 DSM Study by R.W. Beck

DSM Program	Participant	Utility
1) Res Water Heater Tank Wrap	11.20	5.86-11.91
2) Res Water Heat – Showerheads	8.92	4.71-9.87
3) Res Setback Thermostat	16.91	4.10-8.56
4) Res Air Source Heat Pump	5.03	2.52-3.16
5) Res Water Heat Traps	19.36	10.39-22.09
6) Res Water Heat Pipe Wrap	2.76	1.26-2.64
7) Ground Source Heat Pump	0.24	0.00
8) Air Source Heat Pump	0.03	0.00
9) Res Replace Water Heater	0.03	0.00
10) C/I Replace Water Heater	0.00	0.00
11) C/I Replace Heat Pump	0.15	0.00

DoE - 2

Big Rivers IRP Case No. 99-429

Cost-Effectiveness Results from 1995 DSM Study by R.W. Beck – Part 2

DSM Program	Participant	Utility	RIM	TRC
1) Res Water Heater Tank Wrap	11.20	5.86-11.91	0.29-0.58	1.38
2) Res Water Heat – Showerheads	8.92	4.71-9.87	0.28-0.60	1.11
3) Res Setback Thermostat	16.91	4.10-8.56	0.13-1.09	2.02
4) Res Air Source Heat Pump	5.03	2.52-3.16	0.30-0.44	0.62
5) Res Water Heat Traps	19.36	10.39-22.09	0.28-0.63	2.45
6) Res Water Heat Pipe Wrap	2.76	1.26-2.64	0.24-0.52	0.30
7) Ground Source Heat Pump	0.24	0.00	1.03-1.10	0.00
8) Air Source Heat Pump	0.03	0.00	0.99-3.63	0.00
9) Res Replace Water Heater	0.03	0.00	1.42-3.38	0.00
10) C/I Replace Water Heater	0.00	0.00	1.78-3.70	0.00
11) C/I Replace Heat Pump	0.15	0.00	0.75-1.06	0.00

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC

ATTORNEYS AT LAW

August 17, 2000

AUG 18 2000

Mr. Bill Bowker
Acting Executive Director
Kentucky Public Service Commission
211 Sower Blvd., P.O. Box 615
Frankfort, KY 40602-0615

Re: The Integrated Resource Plan of Big Rivers Electric Corporation,
P.S.C. Case No. 99-429

Dear Mr. Bowker:

Enclosed are an original and six (6) copies of the responses of Big Rivers Electric Corporation to the second information requests propounded by the Public Service Commission staff, the Attorney General and the Kentucky Division of Energy.

I certify that a copy of this letter and attachments have been served by mail, postage prepaid, on each of the persons identified on the attached service list.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej

Enclosures

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

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

SERVICE LIST
CASE NO. 99-429

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

Office of the Attorney General of the Commonwealth of Kentucky

John Stapleton
Director of Energy
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Hon. Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Counsel for Natural Resources and Enviromental Protection

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF	)	
BIG RIVERS ELECTRIC CORPORATION	)	Case No. 99-429

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
SECOND REQUEST FOR INFORMATION OF
JULY 13, 2000

Items 1-7

August 18, 2000

1

Item 1) Follow-up to KDOE Item 6b, 1st set:

a) The first paragraph of the witness' response includes the sentence, "The goal of strategic conservation is to reduce overall consumption, with a primary focus on energy." Figure IV-1 of the IRP, however, shows that strategic conservation also reduces the peak load. Isn't it true that reducing the peak load can lead to a reduction in a utility's revenue requirements?

b) Isn't it true that a DSM program that reduces demand by a constant amount all year round can have a Utility Cost ratio greater than 1.0?

c) Isn't it true that the Utility Cost test is also known as the Utility Revenue Requirements test, since it measures the change in revenue requirements?[1]

d) Doesn't it follow from the foregoing that a well-designed and properly-implemented strategic conservation program could reduce the utility's revenue requirements (as well as reducing total resource costs)?

e) Would Big Rivers agree that a reduction in revenue requirements would benefit the utility (as well as the customers)? If not, please explain.

f) The last paragraph of the witness' response to this item includes the sentence, "The only type of measure, within the general category of DSM that will benefit both the utility and the customers, is one which will simultaneously shave peak and (may) fill valleys…" In this sentence, isn't Mr. de Leon focusing only on rate impacts (i.e., on a DSM program's RIM test results)? If not, please explain the response.

[1] Gellings, Clark W. and John H. Chamberlin, *Demand-Side Management Planning*, 1993, Fairmont Press, p. 266.

g) We continue not to understand how the economic impacts on Big Rivers of strategic conservation differ significantly from those of distributed generation. An industrial cogeneration unit, for example, might generate electricity at or near capacity virtually all year round. The Kenergy customer's planned 62-MW cogeneration unit is expected to be available 97% of the time, i.e., almost all year round.[2] Looking at Figure IV-1 of the IRP, it seems clear that a DSM program having this kind of impact would fall into the category of "strategic conservation." We therefore feel the need to reiterate: It seems to KDOE that strategic conservation would also lower peak demands and energy requirements and provide Big Rivers with greater flexibility in its power supply operations. Why does the IRP recommend against strategic conservation, even though it appears to have beneficial characteristics and impacts similar to those of distributed generation?

[2] Response to Attorney General's (AG) Item 1d, 1st set.

Response) a) Not always. If a utility has fixed costs to serve its peak demand prior to the reduction that cannot be changed after the reduction, then the revenue requirements have not changed but rates will be forced to go up if no other source of revenue is available.

b) Yes, however it can also be less than 1.0.

c) Yes, according to some authors.

d) Possibly

e) Not always. For instance, loss of a large industrial load, likened to conservation, would reduce the need for fuel expenditures, however, the fixed costs of the demand requirements, operations and maintenance, and administrative costs would have to be spread over the remaining customers, increasing their rates.

f) No specific test is focused on in this statement. Positive Participant and Utility cost tests, for instance, would benefit both the customers and the utility.

g) The distributed generation contemplated in the IRP would be in use only during peak times when the maximum advantage could be taken in reducing peak demand by a verifiable amount and taking advantage of the anomalies in the current market where wholesale energy can be priced at a higher amount than retail energy during certain hours and savings passed on to the consumer, similar to the recommended C/I load management program. When the cost of wholesale energy dropped below the retail, then the distributed generation would be turned off and energy would be taken from Big Rivers. Strategic conservation does not typically allow such a sculpting of the use of the energy to be developed since it is in effect all of the time.

Witness) Kiah Harris, Burns and McDonnell

2

Item 2) Follow-up to KDOE Item 7a, 1st set: Does the response mean that Big Rivers believes that there are no applications of fuel cells or renewable electric technologies that are presently commercially viable, or that could provide economic benefits to both the utility company and its customers? Please explain.

Response) Yes, it means we believe that there are no presently commercially viable applications of fuel cells or renewable electric technologies as contemplated by the net metering policy that can provide economic benefits to Big Rivers or its member distribution cooperatives' customers considering Big Rivers' current situation. Please see Response to the Attorney General's Second Request for Information, Item No.11.

Witness) Kiah Harris, Burns and McDonnell

3

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
SECOND REQUEST FOR INFORMATION OF JULY 13, 2000

CASE NO. 99-429

Item 3) Follow-up to KDOE Item 8, 1st set: To what degree, if any, did membership in E Source by the National Rural Electric Cooperatives Association give Big Rivers and Burns & McDonnell access to E Source's technical reports, issue briefs, and other technical services?

Response) Membership in E Source by the National Rural Electric Cooperatives Association does not give Big Rivers or Burns & McDonnell access to E Source's technical reports, issue briefs, or other technical services.

Witness) Bill Yeary

4

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
SECOND REQUEST FOR INFORMATION OF JULY 13, 2000

CASE NO. 99-429

Item 4) Follow-up to KDOE Item 18, 1st set:

a. Approximately how many energy use assessments, operation assessments, and coordinated energy and waste assessments are performed annually in the service areas of Big Rivers' member cooperatives?

b. Approximately how much money has been loaned to customers for weatherization and energy efficiency improvements?

c. Please provide a more detailed description of the "work with homebuilders on weatherization and energy efficient construction techniques."

d. If available, please provide the estimated energy and demand impacts of the programs described in the response to KDOE Item 18, 1st set.

Response) a. Big Rivers' members perform an average of 28 such assessments annually.

b. Among the three cooperatives there have been loans of $3,000 in the past two years.

c. Jackson Purchase Energy sponsors an Annual Home Builders Association Dinner. The Home Builders Association Annual Dinner is used to build relationships with regional developers and exchange information about the electric industry and home construction. All three cooperatives sponsor and promote an energy efficient home concept called All Seasons Comfort Home ("ASCH"). The ASCH is a program adopted by the member cooperatives to promote energy efficiency in new homes. For a home to qualify under the ASCH program it must meet the following basic requirements:

- The primary heating and cooling system must be a geothermal system or an electric air-source heat pump.

- All hot water needs must be supplied by electric water heating.

- Minimum requirements for home construction, etc. must be met.

Some ASCH promotional material is included in this response.

d. A comprehensive list of impacts for these programs is unavailable. By the nature of these programs, recommendations are made to customers, the decision to act on the recommendations is left with the customer.

Witness) Russ Pogue

A Builder's Guide To . . .

. . . All Seasons Comfort

Energy Efficiency in New Construction

Builder's Guide

Contents

Introduction

For a home to qualify under the All-Seasons Comfort Home (ASCH) program, the following basic requirements are necessary:

- The primary heating and cooling system must be a geothermal system or an electric air-source heat pump.
- All hot water needs must be supplied by electric water heating.
- Minimum requirements for home construction, and efficiency and installation of the heating and cooling equipment must be met.

Construction materials and techniques described in this booklet are recognized by the electric distribution cooperatives of the Big Rivers Electric system as energy-efficient building practices. These cooperatives also accept other materials and techniques of proven effectiveness that provide equal or better performance.

Graphics Courtesy of
Tennessee Valley Authority

Insulation

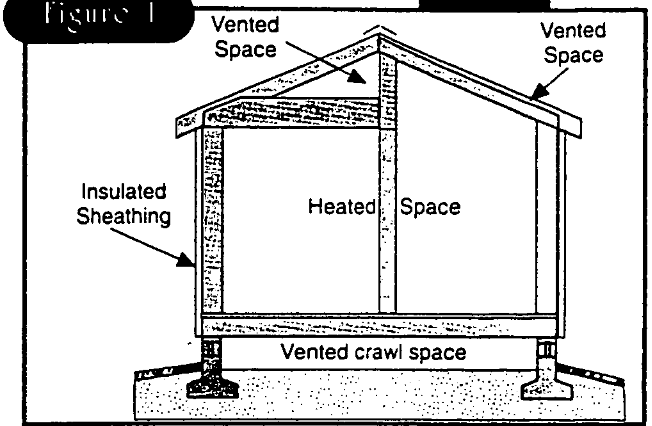
Under normal circumstances, heat flows from an area of higher temperature to an area of lower temperature. That's why in winter, heat from your home tries its best to go outside. In summer, heat from the outside moves into the air-conditioned space in your home.

This heat loss in winter and heat gain in summer makes your heating and cooling system work more. Insulation serves as a barrier to that heat transfer, which means your heating and cooling system has to work less.

The common measure for insulation is a resistance value (R-value). The higher the R-value, the more effective the insulation is in blocking that heat transfer. The R-value is determined by a number of factors, including the material's density and weight — not just its thickness. For example, 6 inches of cellulose or fiberglass insulation is rated as R-19. On the other hand, 6 inches of concrete, a very poor insulator, has an R-value of only 0.5.

Insulating material performance can greatly diminish if improperly installed or exposed to moisture.

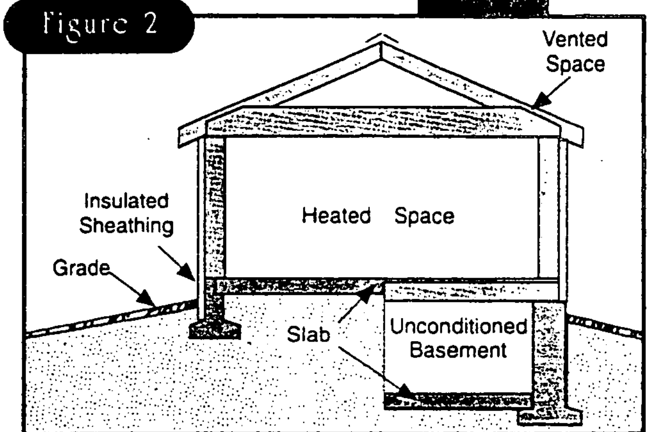
Figure 1



How much insulation do you need?

It depends on whether you're talking about floors, walls, or ceilings. It also depends on what type insulation you plan to use. Your builder or insulation contractor can discuss the type of material that meets the All-Seasons requirements in a cost-effective manner.

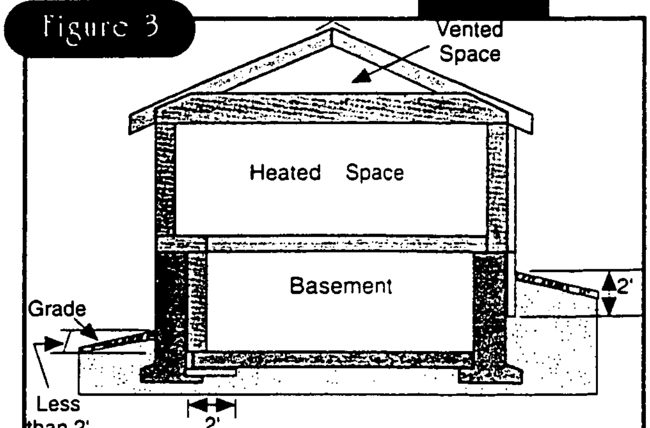
Figure 2



Where do you need insulation?

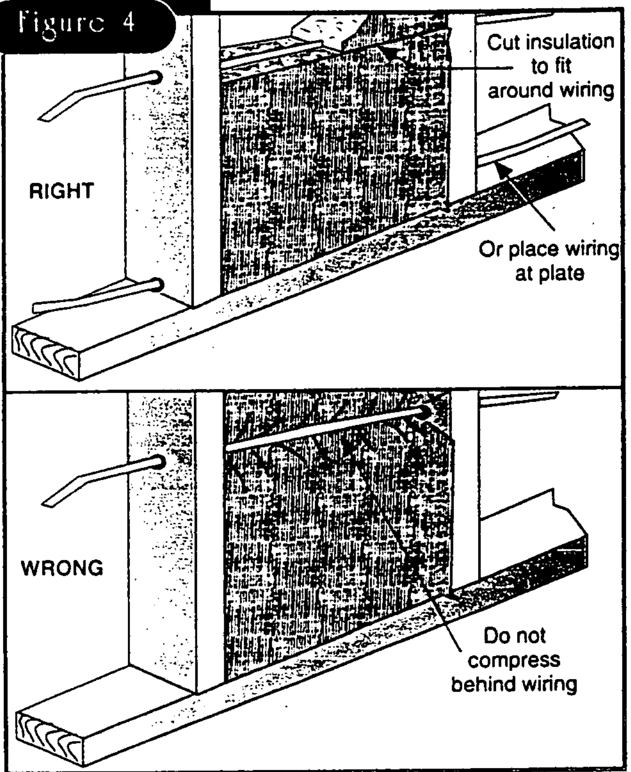
Insulation is needed in areas to separate conditioned space from unconditioned space. Figures 1, 2, and 3 are examples of where insulation is needed. In some cases, you may want insulation for sound-proofing purposes in the conditioned space around a bathroom or bedroom; however, it is not required for the All-Seasons Comfort Home program. Check with your co-op representative before you start construction (and during construction) to insure the proper amount of insulation is being installed where it is needed.

Figure 3



—Walls——

Figure 4



Frame walls built with 2 x 6-inch studs, 24 inches on center, with R-19 blown-in cellulose, meet the ASCH standard. However, 2 x 4-inch wall construction is acceptable with several combinations of insulation. A common method for meeting the wall requirement is R-13 blown-in cellulose with 3/4-inch extruded polystyrene sheathing. Fiberglass blankets (or batts) can also be used to qualify. It should be noted, though, that greater amounts *must be* installed to offset increased air infiltration allowed by fiberglass blankets, especially if improperly installed (Figures 4, 5, and 6).

Fiberglass blankets for wall insulation should be unfaced for use with a separate, continuous vapor barrier. If using faced fiberglass blankets, *make sure* all facing is taped and sealed properly; doing so makes the facing act as close to a vapor barrier as possible.

When installing fiberglass blankets between studs, it is important to cut the insulation to fit around obstructions. The insulation should never be pressed in behind electrical wiring, piping, or other obstacles; doing so greatly reduces its performance.

Figure 5

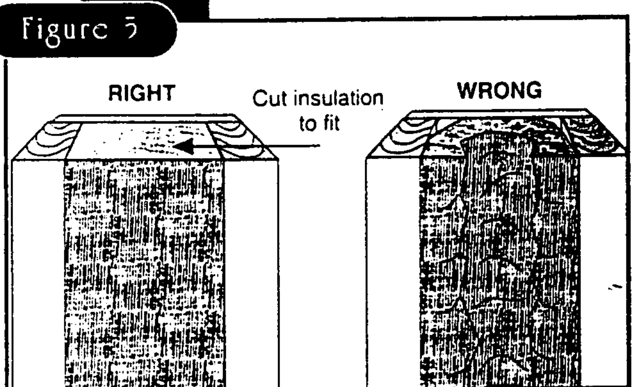
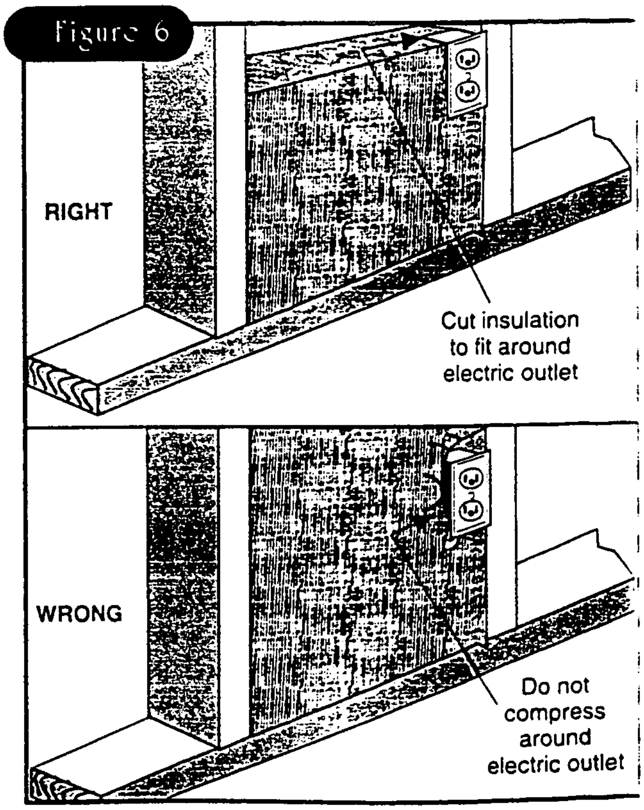


Figure 6



—Ceiling—

The required level of ceiling insulation is R-38, which is about 10 to 12 inches of blown-in cellulose, depending on the density. Fiberglass low-density loose-fill insulation is *NOT* recommended. The insulation should be installed in strict accordance with the manufacturer's instructions and recommendations.

Install the insulation evenly over the entire ceiling surface to provide a uniform R-value. Extend the insulation over the exterior walls as shown in Figures 7 and 8. Insulation baffles should be used to provide the required air space between the ceiling insulation and the roof sheathing where the roof and wall meet. Commercial baffles are moisture-resistant cardboard or plastic, which are inexpensive, and easy to staple into place. Follow the installation directions of the manufacturer.

Energy savings can be realized when the full insulation thickness can be installed all the way to the outside face of the wall at the eaves, as long as sufficient air space is maintained. This can be accomplished by using a king post truss with the top chord raised at the exterior wall to provide room for the full thickness of insulation.

NOTE: *Reducing the thickness of ceiling insulation near the eaves can sometimes create moisture problems because of condensation.*

If two layers of high-density fiberglass blankets are used, the second layer should be unfaced and installed crosswise to the first layer to lower air infiltration at the joints.

To maintain the required depth of insulation below attic walkways, a raised walkway (Figure 9) may be used. Remember to build the walkway *prior* to the installation of the insulation.

Cathedral Ceiling: Cathedral ceilings insulated with a fibrous-type insulation installed between the room/ceiling rafters require vent openings at the eaves and ridge, and between each rafter spacing. A minimum of 1-inch air space is required.

If an exposed-beam-and-ceiling effect is desired, several inches of rigid insulation board can be installed above the beams and ceiling (Figure 10). Local building codes may require a fire-rated material such as gypsum board between most foam board insulations and the living space. Consult local codes for the requirements on specific products. Also keep in mind that the total area for a cathedral ceiling should not exceed 30 percent of the entire ceiling area.

Figure 7

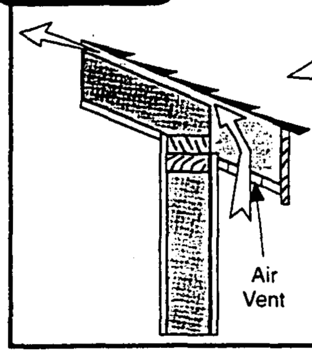


Figure 8

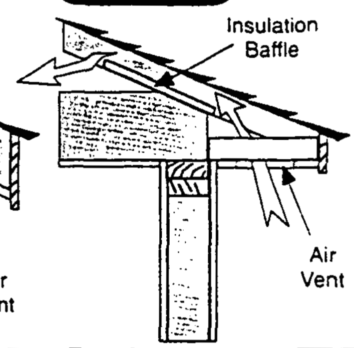


Figure 9

A passageway should be provided to permit access through the attic without compressing the insulation. For attic storage expand the areas as illustrated.

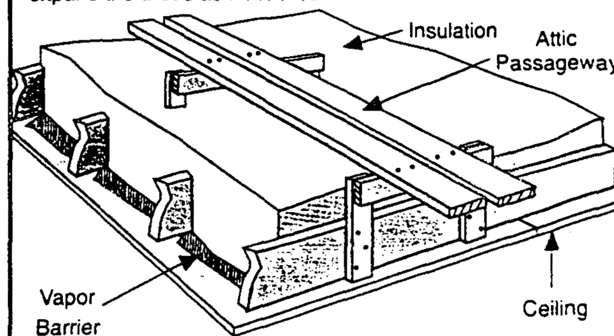
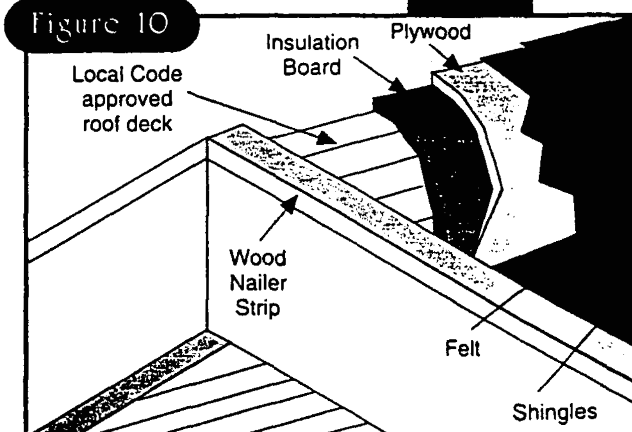


Figure 10



Item
8 of 22

Figure 11

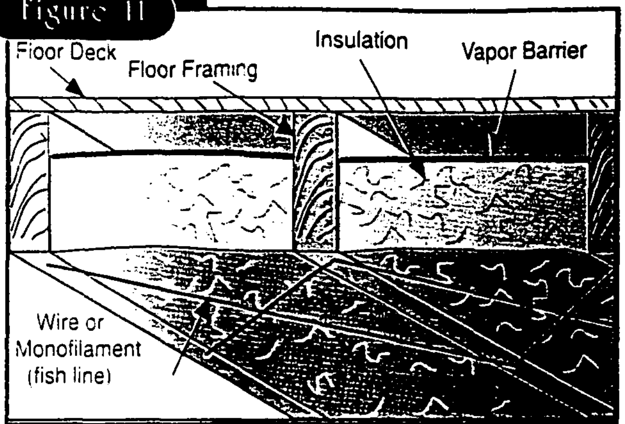


Figure 12

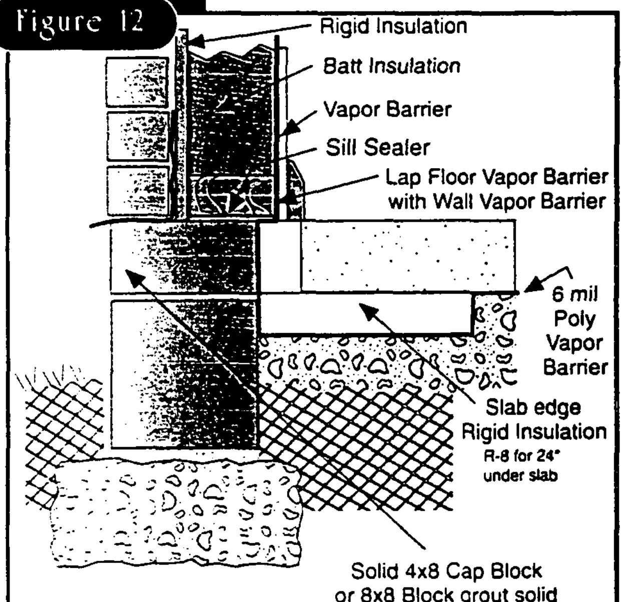
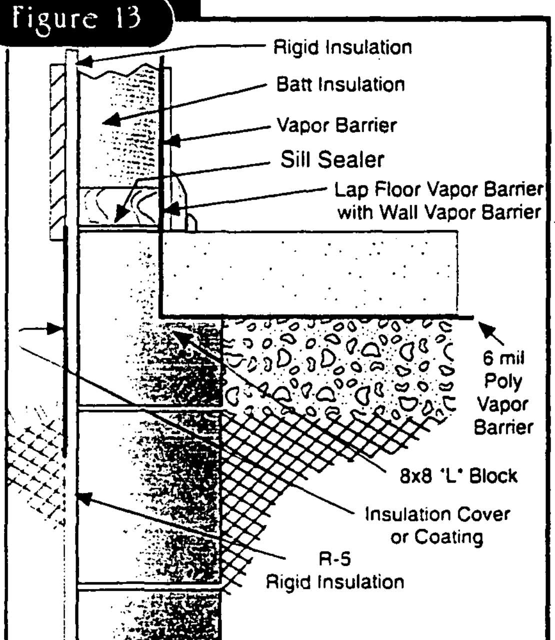


Figure 13



—Floors—

Believe it or not, there are still some builders in Kentucky who argue that no floor insulation is needed. That simply is *NOT* true. Insulation between the floor joists is critical in preventing heat loss through the floor. The required amount is R-19 if using fiberglass blankets, R-13 for blown-in cellulose. However, blown-in insulation may not be cost-effective in floor applications because of the increased cost for adhesives needed to bind the insulation to the floor.

Crawl Space or Unheated Basement: Fiberglass is the most common floor insulation used. It is best to install the insulation flush with the **bottom of the floor joists**, leaving an air space between the top of the insulation and floor sheathing (Figure 11). The additional air space adds to the insulation's efficiency. When using faced insulation, always install the facing toward the living area.

Floor insulation may be turned up at the ends to provide the required insulation around the floor's perimeter. If blown-in insulation is being used in the walls, it would be best to have the insulation contractor blow-in insulation around the floor perimeter.

It is important to provide some support for floor insulation. Otherwise, gravity will cause it to sag. Some typical ways to support the insulation and hold it in place are wire stays, monofilament (Figure 11), or wire mesh . A sheet of polyethylene or other material that might form a vapor barrier *should not be* used as support for the insulation.

Slab Floor: If not properly insulated, concrete slab floors lose heat around the perimeter. Slab floors should be insulated to an R-8 if the edge of the slab is buried less than two feet below grade. The vertical edge should be insulated. In addition, the insulation should continue horizontally under the slab for at least two feet, or down vertically for two feet, or to the top of the footing (Figures 12 & 13). Slabs more than two feet below grade are adequately insulated by the surrounding earth.

Uninsulated Floor Over A Heated/Unheated Basement: If the basement is heated, basement walls that are completely above grade should be insulated to R-13. Walls that are partially below grade should be insulated to at least two feet below grade with R-5 (Figure 3 - Pg. 1). If the basement is unheated, you may choose to insulate the basement walls above grade instead of the floor above.

Windows

Not all windows are the same. Windows, like insulation and other building products, are rated by the industry for effectiveness in reducing heat loss and heat gain (Figures 14 and 15). The window required for the All-Seasons Comfort Home is a double-pane, Low-E, gas-filled window. The "E" in Low-E stands for emissivity, or the window's ability to block heat transfer. Low-E glass boasts a thin metallic layer that serves two purposes. First, it blocks some ultraviolet light during summer, which minimizes heat gain. In winter, it reflects heat back into the room. The gas between the two panes of glass serves as an additional restraint against heat loss.

In addition to the type windows used, the amount of window space is also a consideration for the All-Seasons Comfort Home. The recommended window area is 10 percent of total heated and cooled floor space. In other words, if you are building a home with 2,000 square feet, window area (including sliding glass doors) should not exceed 200 square feet. If your window area is less than 10 percent, you earn bonus deductions.

Figure 14

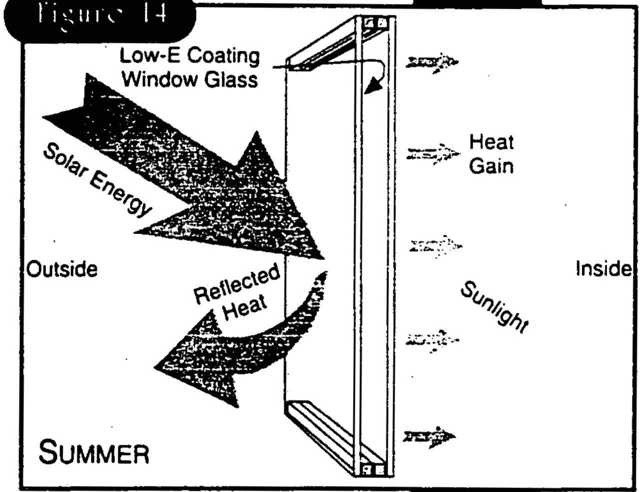
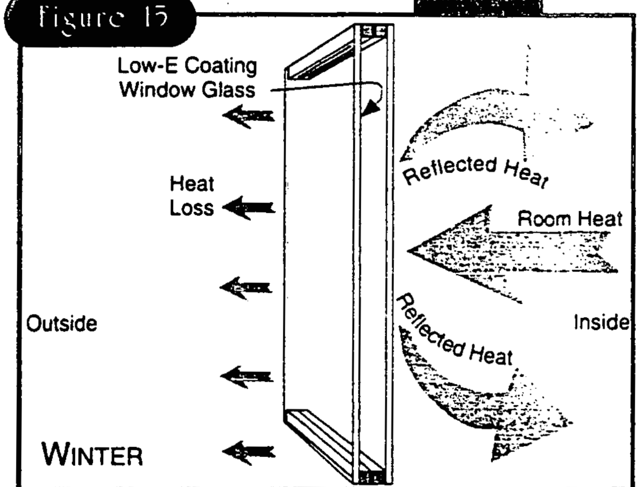


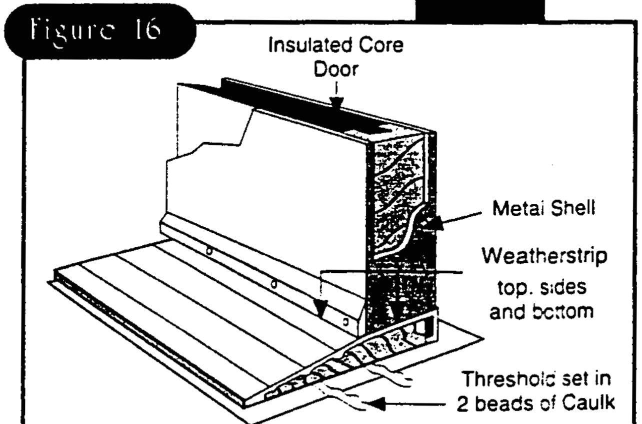
Figure 15



Doors

Meeting ASCH standards is simple when it comes to doors. Simply install a metal door with a foam core for exterior doors. A door that does not separate heated and cooled space from an unconditioned space is not required to be insulated. Exterior doors should have a minimum thermal resistance value of R-7. Regular or standard storm doors are not considered insulated doors. All exterior doors should include weatherstripping and caulking of the threshold (Figure 16).

Figure 16



Air Infiltration

A surprising amount of energy is wasted because of air infiltration. Uncaulked cracks around windows and doors are the most common energy thieves when it comes to infiltration. A tiny 1/16-inch crack around a door is the equivalent of having a 4-inch-by-4-inch hole in the wall. Gaps around windows and doors should be stuffed with insulation, or filled with polyurethane foam to prevent air infiltration (Figure 17).

Caulk or foam around all penetrations for plumbing, electrical equipment, or other outside penetrations (Figure 18). Mechanical equipment protruding through the ceiling into the attic should be sealed to lessen the amount of warm air leaked to the attic (Figure 19). This includes hoods and bathroom vents. Make sure the caulk used around heat producing penetrations has been approved for such applications.

Electrical outlets in walls can be sealed by fire retardant foam covers inserted between the electric box and the receptacle covers (Figure 20).

Figure 17

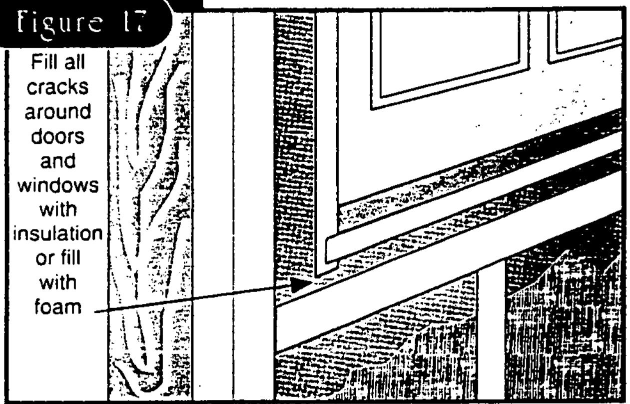


Figure 18

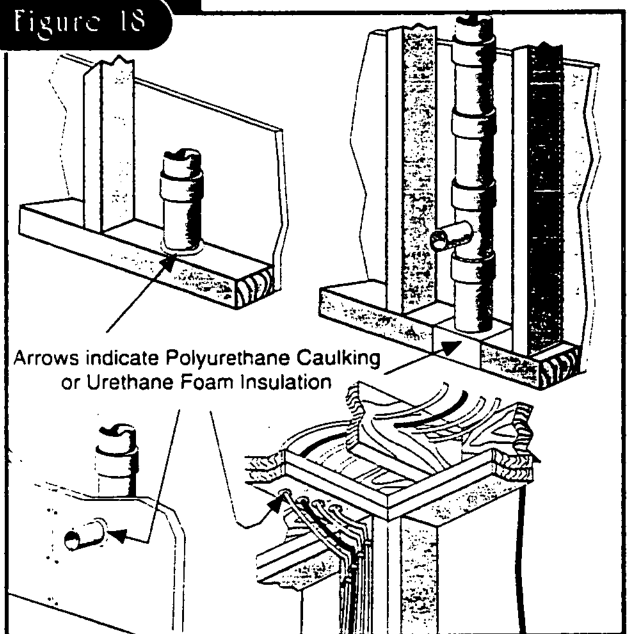


Figure 19

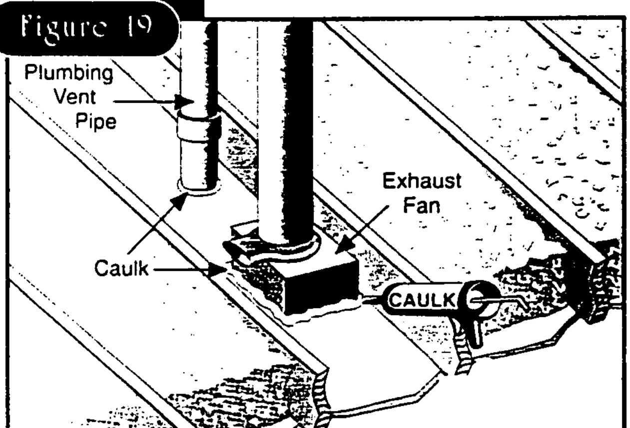
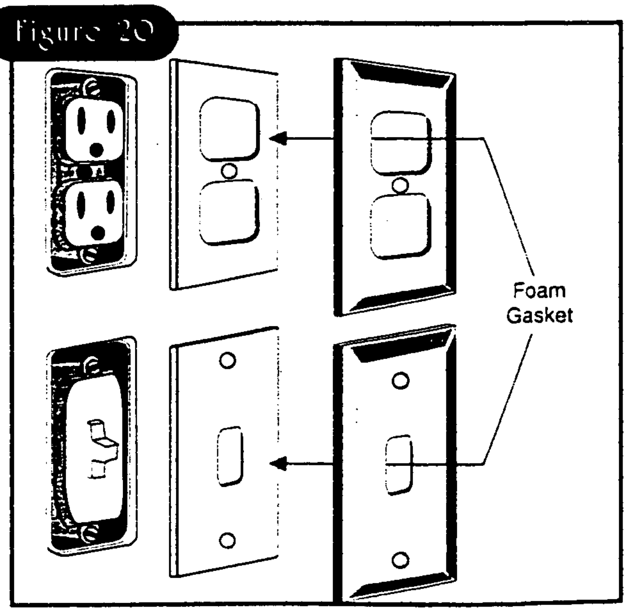


Figure 20



—Air Infiltration —
Continued

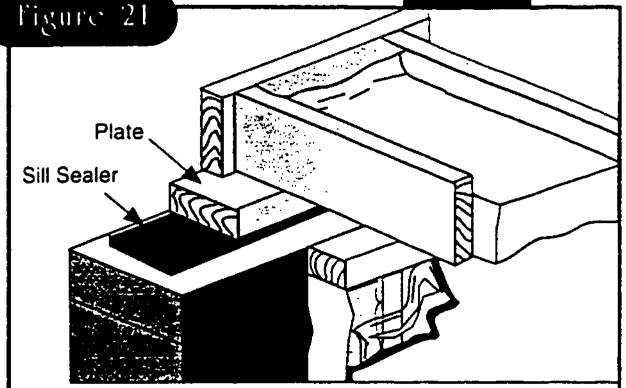
Sole plates should be sealed with sill sealer, caulking, or the equivalent (Figures 21-24).

Vapor Barrier: Tightly-built homes help homeowners save on their energy bills. The accompanying reduction in infiltration rates, however, requires greater attention to the control of moisture and its sources to prevent the development of moisture-related problems. Poor moisture control can cause reduced insulation performance, visual damage, and long-term structural damage.

In winter, cold outside air retains little water vapor, but warm inside air accumulates a considerable amount of water vapor from cooking, washing, bathing, etc. As the water vapor accumulates in the house, pressure increases causing water vapor to move through the permeable building materials of ceilings, walls, and floors toward the outside colder, drier air. If the dew point is reached within the ceiling, wall, or floor components, the water vapor will condense into water. This can cause damage such as blistering and cracking of paint, and discoloration from mildew forming on the outside walls. Prolonged exposure to moisture can ultimately result in decay and structural damage.

Exhaust fans with backdraft dampers are efficient and highly recommended for use in areas that produce lots of moisture such as bathrooms, kitchens, and laundries. The fans remove moist air directly to the outside (Figure 25). This air should not be discharged into the attic or crawl space since moisture can also cause problems in these areas. *Be sure* to observe any manufacturer's instructions on insulating around or over an exhaust fan.

Figure 21



(For a conditioned basement install Sill Sealer)

Figure 22

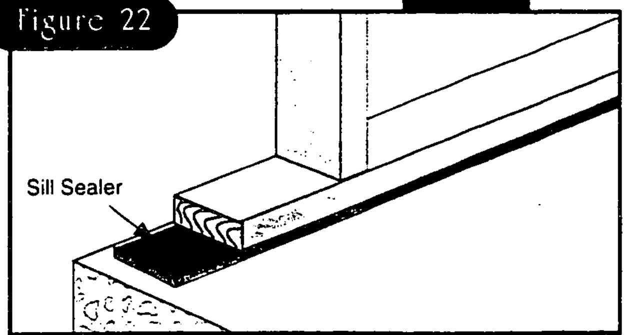


Figure 23

(Preferred)

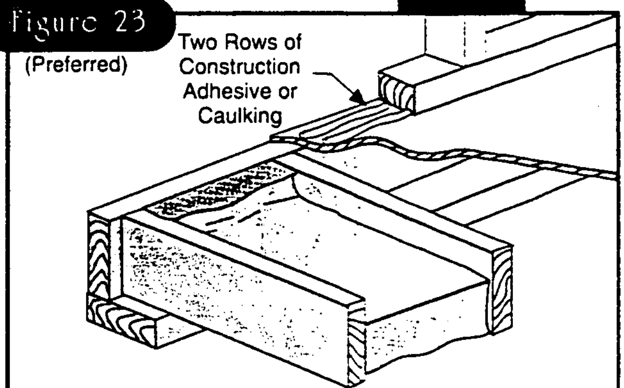


Figure 24

(Sealant under sole plate is preferred)

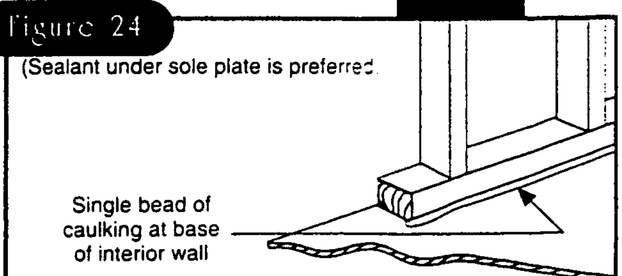
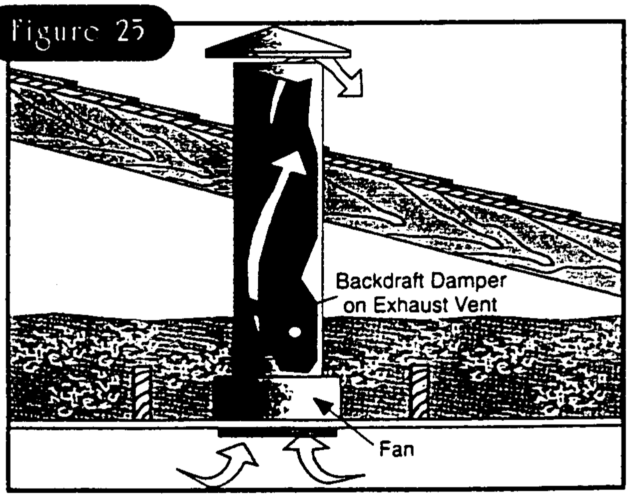


Figure 25



—Air Infiltration —
Continued

Figure 26

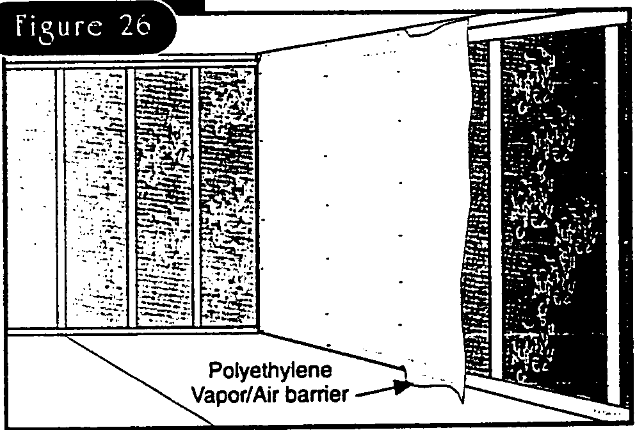


Figure 27

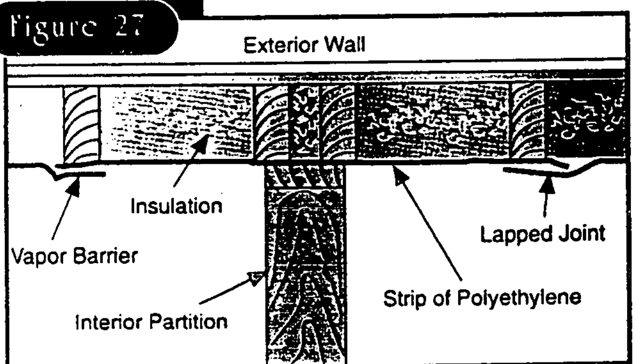
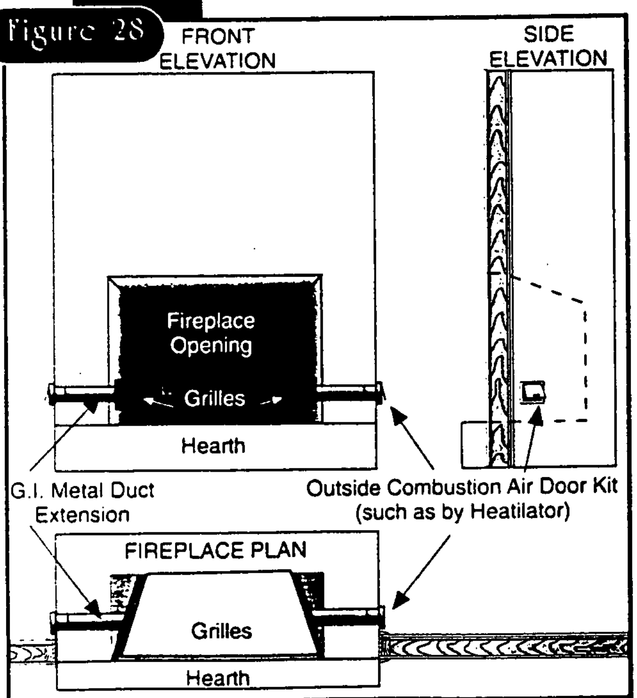


Figure 28



Vapor barriers and natural ventilation are adequate for controlling moisture in other areas of the home where moisture is not as highly concentrated (Figure 26). Vapor barriers are located on the "living side" of the insulation. A continuous wall vapor barrier such as 4-mil or 6-mil polyethylene is recommended. In addition to controlling moisture, the continuous vapor barrier blocks some air infiltration through the wall.

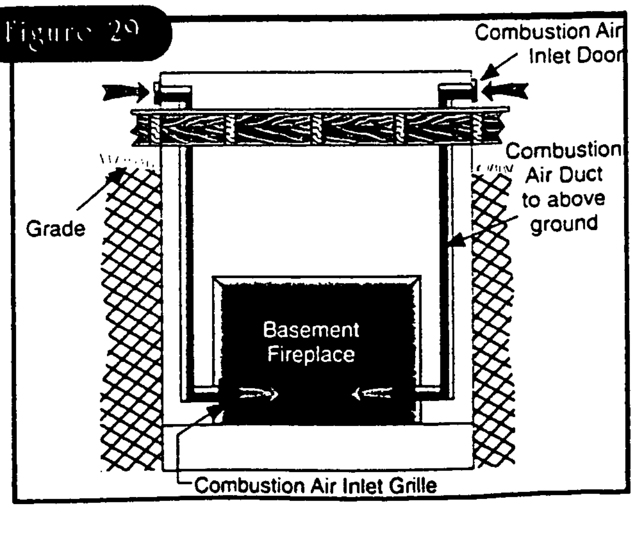
In order for the vapor barrier to be effective, it must be installed properly and carefully. Keep the vapor barrier free of tears and punctures. Repair any tears that do occur. Overlap the joints of polyethylene sheets to make the vapor barrier continuous (Figure 27).

Air Infiltration Barrier Outside (Housewraps): Housewraps are made from different materials that vary in performance. The primary purpose of these products is to reduce air infiltration. A housewrap is not intended to replace an interior vapor barrier. It is an air leakage barrier, installed on the outside framing of the house. The housewrap should have a high vapor transmission rate to prevent moisture from being trapped behind it.

Fireplace: Although attractive and desirable to many homeowners, fireplaces are not an efficient way to provide home heating. Worse, they provide a path for heated air to escape. To reduce this escaping air, a fireplace should have a tight-fitting damper and tight-fitting doors.

An outside source of combustion air is recommended to provide a sufficient amount of air to fuel the fire without using heated air from the house (Figures 28 and 29).

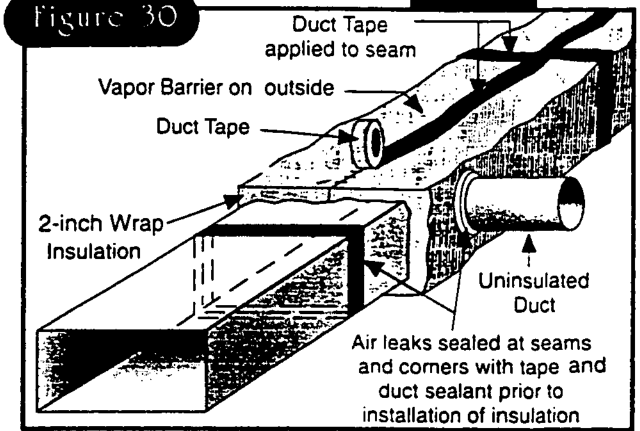
Figure 29



Duct Work

The performance of the heating and cooling system will depend heavily on the duct work. That's why, when possible, the ducts should be located in the conditioned space. Locating the ducts outside the conditioned space will waste as much as 20 percent of the energy consumed by the heating and cooling system. If the ducts cannot be located in the conditioned space, they *must be* insulated to R-6, sealed with mastic (or similar type sealant), and taped (Figure 30).

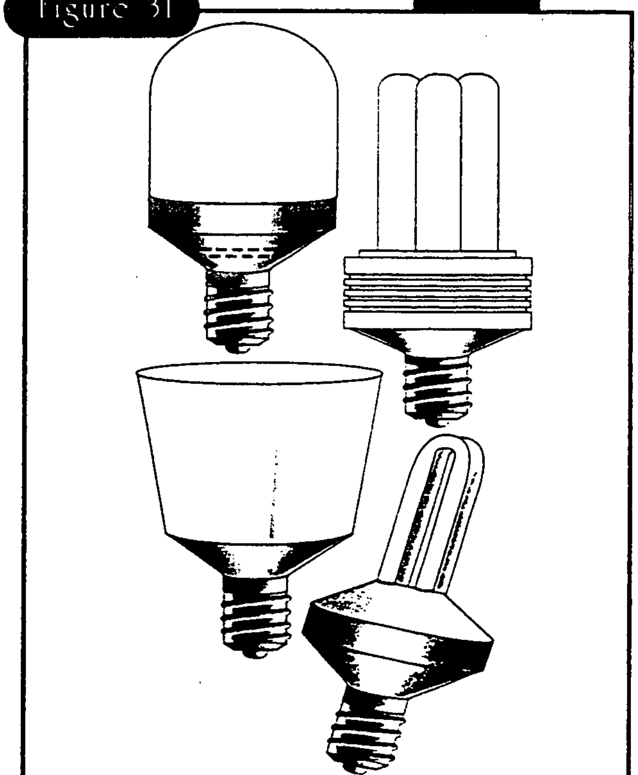
Figure 30



Lighting

When it comes to building a home that will have low energy bills, don't overlook lighting. Lighting accounts for approximately 12 percent of all electricity used in the home. An All-Seasons Comfort Home must have fluorescent lighting in at least 10 percent of all *fixed* lighting. The selection of compact fluorescents that are available (Figure 31) makes choosing fixtures easier than in previous years. By installing more than 50 percent fluorescent lighting, you not only earn a bonus deduction, you will reduce your lighting costs by more than 50 percent.

Figure 31



Location of Heating & Cooling Unit

If an electric air-source heat pump is installed, the outdoor unit should be installed on the south side of the home and shaded. Locating an outdoor unit on the north or west side of the home uses more energy and makes the home less comfortable.

A geothermal system with a desuperheater should be central to water heating needs. This prevents long runs of hot water from the water heater to point of use.

Proper sizing of the heating and cooling system and the ducts are critical factors. In fact, it may be the single most important factor you as a homeowner can control. Ask a representative from your co-op to assist in the sizing of your heating and cooling equipment and duct system.

Heating & Cooling Unit

Central heating and cooling is preferred by most people. And at the heart of the All-Seasons Comfort Home is a highly-efficient heating and cooling central system. The most efficient method to heat and cool is with a geothermal system. It cools like any central air conditioning system and provides heat more efficiently than any heating system you can buy. Most geothermal systems can provide a portion of your home's hot water needs as well.

The second best way to heat and cool your home is with a high-efficiency electric air-source heat pump. Like geothermal systems, heat pumps provide central air and heat at extremely high efficiency levels. Choosing a high-efficiency electric heat pump, or a geothermal system to heat and cool your new home is a no-lose situation. They both provide year-round comfort, along with significant energy savings for you and your family.

Air-Source Heat Pumps: The minimum efficiency for split-system heat pumps is 12 SEER (Seasonal Energy Efficiency Ratio). Single package heat pumps have the compressor, air handler, and heat exchanger in an outdoor unit. Single package systems must meet a minimum efficiency of 10 SEER (single package information not included in the construction scorecard).

Geothermal Systems: The minimum efficiency for a closed-loop geothermal system is 11 EER (Energy Efficiency Ratio). For an open loop, the minimum is 12 EER.

You can earn bonus deductions for units rated at higher efficiency levels than the minimums. For example: installing a 14 SEER split-system heat pump rather than the minimum 12 SEER will earn you six bonus deductions. So if your home is on the borderline to qualify as an All-Seasons Comfort Home, consider increasing the efficiency of your heating and cooling unit.

Check with your electric co-op representative for more details.

Notes

Produced by Big Rivers Electric Corporation on behalf of its member systems:

Meade County Rural Electric Cooperative Corporation
P. O. Box 489, Brandenburg, KY 40108
(502) 422-2162

Jackson Purchase Electric Cooperative Corporation
P. O. Box 3188, Paducah, KY 42002
(800)633-4044 (502) 442-7321

Henderson-Union Rural Electric Cooperative Corporation
P. O. Box 18, Henderson, KY 42420
(800) 844-4832 (502) 826-3991

Green River Electric Corporation
P. O. Box 1389, Owensboro, KY 42302
(502) 926-4141

All-Seasons Comfort Home
Construction Scorecard

Following are various construction methods that have a direct impact on the amount of energy used in your home. Each category is assigned various possible points. In order for your home to qualify as an All-Seasons Comfort Home, you must accumulate 100 (or more) points on this scorecard.

If you follow the recommended point totals for each of the main building components, your home will qualify for the program. The recommended point total is listed in the heading of each main building component. If you do not meet a recommended component's point total, you will have to make up the amount in some other category. In some instances you might exceed the recommended point total for a particular component. In that case, you will receive more points than recommended. For example: the recommended point total for ceiling insulation is 20 (which is R-38), if you install R-44 insulation you will receive 22 points, exceeding the recommended amount by 2 points.

*Please note: the primary heating/cooling system must be either a geothermal system or an electric heat pump.

Main Building Components

1. Exterior Wall Insulation - Recommended Total = 20 Points

(for basement walls see 3C)

	check one
R-13 Blown-in cellulose insulation	❐ 15
R-19 Blown-in cellulose insulation	❐ 22
R-13 Fiberglass blankets	❐ 10
R-19 Fiberglass blankets	❐ 14

Exterior insulation listed below to be used with the above insulation

1-inch extruded polystyrene	❐ 6
3/4-inch extruded polystyrene	❐ 5
1/2-inch Tough-R	❐ 5
1/2-inch extruded polystyrene	❐ 4
1/2-inch blackboard	❐ 2
1/2-inch plywood	❐ 1

1. Total Wall Points ________

2. Ceiling Insulation - Recommended Total = 20 Points

Main Ceiling

R-30	❐ 15
R-38	❐ 20
R-44	❐ 22
R-50	❐ 25

Cathedral Ceiling (not to exceed 30 percent of floor area)

R-19	❐ -3
R-26	❐ 0
No cathedral ceiling	❐ 0

2. Total Ceiling Points ________

Building Components . . . Continued

3. Floor (choose type A, B, or C) - Recommended Total = 15 Points

A. Floor over crawl space or unheated basement Insulation

No Insulation	❐	-38
R-13 Fiberglass blankets	❐	9
R-19 Fiberglass blankets	❐	15
R-22 Fiberglass blankets	❐	17
R-8 Blown cellulose on crawl space foundation wall	❐	15

B. Slab floor (perimeter insulation)

No perimeter insulation	❐	-15
R-5	❐	8
R-8	❐	15
R-11	❐	18

C. If floor is not insulated or if basement is heated, basement walls should be insulated. Group similar walls together and score accordingly.

Completely exposed basement walls: (more than six feet above grade)		
No insulation	❐	-7
R-13 Fiberglass	❐	8
R-13 Blown-in cellulose	❐	11
R-19 Fiberglass	❐	11
Partially exposed basement walls: (two to four feet above grade)		
No insulation	❐	0
R-3 Rigid foam	❐	3
R-5 Rigid foam	❐	5
R-13 Fiberglass	❐	8
Completely below grade basement walls: (more than six feet below grade)		
No insulation	❐	0
R-3 Rigid foam	❐	1
R-5 Rigid foam	❐	2
R-13 Fiberglass	❐	4
Band joist sprayed with cellulose or insulated with R-19 fiberglass	❐	0
Band joist not insulated	❐	-4

3. Total Floor Points _______

4. Windows - Recommended Total = 10 Points

Double pane, clear glass	❐	5
Double pane, Low-E, gas filled	❐	10
Triple pane, Low-E, gas filled	❐	12
Window area 10% of home's total floor area	❐	0
For each percentage less than 10% of floor area, add one bonus point	❐	_____ points
For each percentage greater than 10% of floor area, deduct one point	❐	_____ points

4. Total Window Points _______

5. Exterior Doors - Recommended Total = 5 Points

Solid wood core	❐	2
Metal with foam core	❐	5

5. Total Door Points _______

Building Components . . . Continued

6. Air Infiltration - Recommended Total = 20 Points

A. Each sealed opening and penetration component is worth 2 points

(Check n/a if not applicable and score two points)

n/a			
____	Recessed light fixtures	points	____
____	Pipe penetration	points	____
____	Duct penetrations	points	____
____	Windows and doors	points	____
____	Exhaust fans	points	____
____	Electrical wiring penetrations	points	____
____	Dryer vent	points	____

B. Air-Infiltration Barrier

Fiberglass insulation used in exterior walls: Continuous air-infiltration barrier outside (housewrap), all seams taped and sealed.................................❒ 6

Blown-in cellulose used as air barrier...❒ 6

C. Fireplace

Tight-fitting door and damper ....❒ 0

Tight-fitting door, damper, and outside air source..❒ 1

No door or damper on fireplace...❒ -14

No fireplace...❒ 3

6. Total Air-Infiltration Points ________

7. Duct Work - Recommended Total = 10 Points

Contact your co-op representative for scoring in this category.

R-4 Duct work insulation, ducts sealed with mastic in R-8 insulated crawl space...❒ 10

R-6 Duct work insulation, ducts sealed with mastic in R-8 insulated crawl space...❒ 15

R-4 Duct work insulation, ducts sealed with mastic in enclosed crawl space...❒ 0

R-6 Duct work insulation, ducts sealed with mastic in enclosed crawl space...❒ 5

All duct work sealed with mastic in conditioned living space.........................❒ 20

R-6 Duct work insulation, ducts sealed with mastic in attic, exterior wall, or open crawl space...❒ -5

R-19 Duct work insulation, ducts sealed with mastic in attic, exterior wall, or open crawl space...❒ 8

All duct work buried in or under concrete slab with R-5 perimeter insulation...❒ 0

7. Total Duct Work Points ________

8. Bonus Category (Check All That Apply)

A. Heating and Cooling System

NOTE All heating and cooling systems must meet minimum efficiency standards. 12 SEER electric heat pump split system, 11 SEER packaged system, and 12.5 EER geothermal systems -- to qualify for the ASCH program.

Split system electric heat pumps

12 SEER Electric heat pump ....❒ 0

13 SEER Electric heat pump ....❒ 1 bonus

14+ SEER Electric heat pump ....❒ 2 bonus

Bonus Category . . . Continued

Packaged heat pumps

11 SEER Electric heat pump ☐	0
11.5+ SEER Electric heat pump ☐	1 bonus
12.0+ SEER Electric heat pump ☐	2 bonus

Geothermal Systems

13 EER Geothermal system ☐	0
14+ EER Geothermal system ☐	2 bonus
15 EER Geothermal system ☐	4 bonus
16+ EER Geothermal system ☐	6 bonus

B. Lighting

Lighting formula: square footage of home x .9 = lighting watts needed
Lighting watts needed x .25 x percentage desired (10%, 30%, 50%, etc.)
= fluorescent watts needed

Less than 10% fluorescent lighting ☐	0
10% Fluorescent lighting ☐	1 bonus
30% Fluorescent lighting ☐	3 bonus
50% Fluorescent lighting ☐	5 bonus

C. Outdoor (heat pump) unit properly located ☐	1 bonus
D. Two-speed or variable-speed heating and cooling system ☐	2 bonus
E. Indoor (geothermal) unit centrally located ☐	1 bonus
F. Light-colored roof ☐	1 bonus
G. Heat recovery ventilation system installed ☐	4 bonus
H. Heat pump water heater installed (located in basement) ☐	1 bonus
I. Programmable thermostat ☐	1 bonus
J. Adjustable mini-blinds between panes of glass ☐	1 bonus
K. On-demand water heating or desuperheater installed ☐	1 bonus
L. Storm doors ☐	1 bonus

Construction Points ________
Bonus Points (+) ________
Total Score (=) ________

Builder/Contractor Certification

I, ______________________________
(Name)

as ______________________________
(Title)

of ______________________________
(Company Name)

hereby certify that the residence constructed for

____
(Homeowner)

meets the standards as indicated herein and that the house rating indicated above is correct.

____
Builder/Contractor's Signature

Homeowner's Statement

I/We ______________________________
(Homeowner)

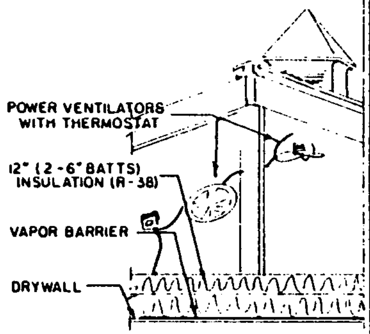
understand and accept that the payment received from ______________________________
(Utility)

does not in any way constitute a warranty or representation by the cooperative that the above residence meets the standards contained herein.

____
Homeowner's Signature

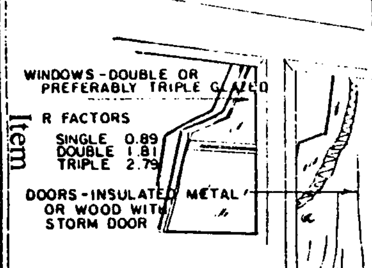
Energy Conservation Begins At Home

ROOF & CEILING

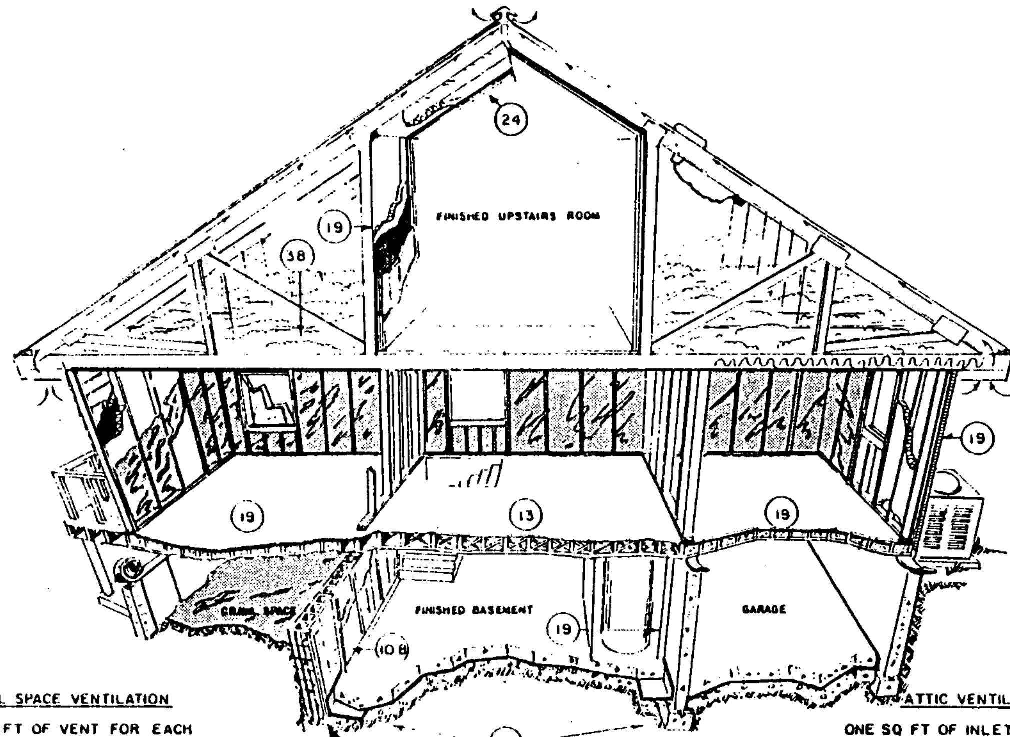


NOTE: CEILING INSULATION-R38
MATERIELS: 12" (2-6" BATTS) OR 1-6" BATT PLUS 5" BLOWN OR 10" BLOWN/FOAM

WINDOWS AND DOORS



NOTE: ALL DOORS WEATHERSTRIPPED
WINDOWS CAULKED
OTHER CRACKS SEALED WITH POLY FOAM



CRAWL SPACE VENTILATION

ONE SQ FT OF VENT FOR EACH 1500 SQ FT OF CRAWL SPACE – AT LEAST 2 VENTS REQUIRED.

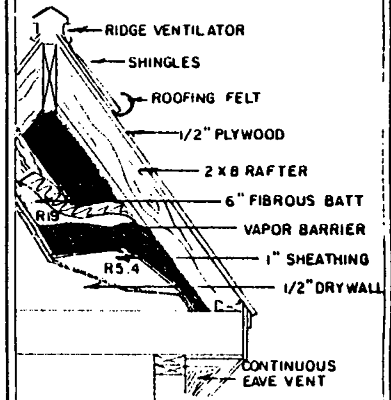
PERIMETER INSTALLATION

ATTIC VENTILATION

ONE SQ FT OF INLET PLUS ONE SQ FT OF OUTLET FOR EACH 600 SQ FT OF CEILING AREA

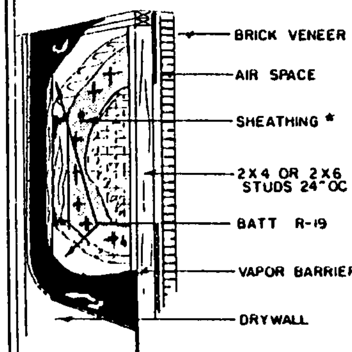
(10) R-FACTOR

ROOF & CEILING



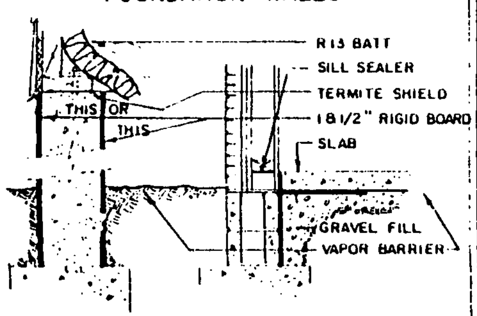
NOTE: 1-1/2" OF AIR SPACE IS TO BE ALLOWED BETWEEN BATTING AND PLYWOOD FOR AIRFLOW.

EXTERIOR WALLS



*NOTE: WHEN USING 2X4 STUDS, INSULATION SHEATHING (R-5.4)

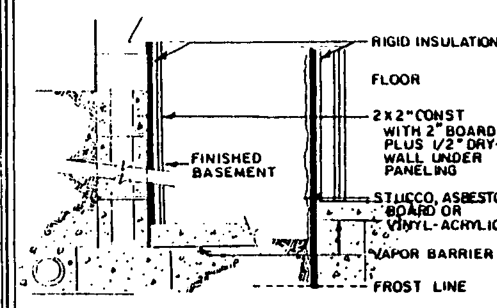
FOUNDATION WALLS



— OTHER ENERGY CONSERVING MEASURES —

- ✓ ALL EXTERIOR CRACKS AROUND DOORS, WINDOWS AND JOINTS CAULKED WITH NON HARDENING PRODUCT.
- ✓ EXTERIOR DOORS WEATHER STRIPPED. METAL DOORS INSULATED, WOOD DOORS WITH STORM DOOR.
- ✓ FIREPLACES WITH GLASS DOORS AND EXTERIOR MAKEUP AIR INLET. WITHOUT THESE FEATURES, ADD ON 10% COST.
- ✓ AIR HANDLER LOCATED NEAR CENTER OF HOUSE FOR EVEN DISTRIBUTION OF HEAT-COOLING.
- ✓ HEATING AND COOLING DUCTS IN UNHEATED SPACES SHOULD BE INSULATED.
- ✓ EXTERIOR WINDOWS NOT TO EXCEED 8% OF LIVING SPACE FOR DOUBLE GLAZED, 10% FOR TRIPLE GLAZED.
- ✓ KEEP INSULATION AWAY FROM RECESSED LIGHT FIXTURES - REFER TO NEC CODE (ARTICLE 410-66)
- ✓ USE RIDGE & SOFFIT VENTILATION FOR REMOVING MOISTURE—KEEPS HOUSE COOLER IN SUMMER, WARMER IN WINTER-ALSO REDUCES BUCKLING.
- ✓ MAINTAIN PROPER MOISTURE CONTROL WITH HUMIDIFIER-DEHUMIDIFIER - ITS AN ESSENTIAL PART OF THE HEATING/COOLING PROCESS.
- ✓ LANDSCAPE FOR FUNCTION AS WELL AS FOR APPEARANCE – DECIDUOUS TREES ON SOUTH SIDE FOR SHADE IN SUMMER, CONIFEROUS ON NORTH AND NORTHWEST TO REDUCE EFFECTS OF WINTER WINDS AND STORMS.
- ✓ INSULATION BOARD INSTALLED ON EXTERIOR SURFACES MUST BE PROTECTED FROM THE SUN FROM THE GRADE LINE UP TO THE FINISH MATERIEL. (VINYL-ACRYLIC LATEX OR OTHER COATINGS SHOULD BE USED).

FOUNDATION WALLS



5

Item 5) Follow-up to KDOE Item 19, 1st set:

a. Do the terms "stranded" and "fleeting" investments refer to a restructured utility industry that may be instituted in Kentucky at some time in the future?

b. What is Big Rivers' best estimate as to when (or whether) electric industry restructuring may occur in Kentucky?

c. Is Big Rivers aware of KRS 278.285, which authorizes the Commission to consider and approve "a utility's proposal to recover in rates the full costs of demand-side management programs, any net revenues lost due to reduced sales resulting from demand-side management programs, and incentives designed to provide positive financial rewards to a utility to encourage the implementations of cost-effective demand-side management programs"? Please discuss the concepts of "stranded" and "fleeting" investments in the context of this statute.

d. Referring to the first paragraph of the response, is the witness aware that changes in revenue requirements are measured most directly by the Utility Cost (UC) test?

e. Part (a) of the response to this item contains the phrase, "it is likewise the members responsibility to serve all ratepayers (RIM test)…" Part (b) of the response contains a similar phrase: "all-ratepayers test (RIM)". The last paragraph on page IV-3 of the IRP, however, contains the following sentences: "The Total Resource Cost (TRC) test is a measure of a program's benefits versus costs for all ratepayers, and is sometimes called the 'all ratepayer' test. The Rate Impact Test (RIM) is a measure of rate impacts for a utility." KDOE concurs with the sentences in the IRP and believes that the phrases that associate the all-ratepayer test with the RIM test are incorrect.[3] Please explain this discrepancy.

f. Would it be accurate to say that the primary criterion used by Big Rivers for the past six years or more when deciding which DSM programs to implement has been the effect on rates (RIM test)? If not, please explain.

g. The section on "Necessity, Function, and Conformity" of the IRP regulation, 807 KAR 5:058, refers to utility plans "to meet future demand with an adequate and reliable supply of electricity at the *lowest possible cost for all customers* within their service areas..." (emphasis added). In view of this regulation and Question (e) above, would Big Rivers agree that the primary criteria showing whether all ratepayers are being optimally served should be the TRC, or All Ratepayers test? If not, please explain.

[3] Gellings and Chamberlin, pp.260,263.

Response) a. Yes.

Witness) Kiah Harris, Burns and McDonnell

b. Big Rivers is not prepared to estimate when or whether electric industry restructuring may occur in Kentucky.

Witness) David Spainhoward

c) Yes, Big Rivers is aware of KRS 278.285. If an investment in a cost effective DSM program became stranded due to retail competition, then it would be against market logic for Big Rivers to raise rates to its remaining customers under KRS 278.285 and become less competitive due to a stranded DSM investment that was found to be beneficial under a regulated environment.

Witness) Kiah Harris, Burns and McDonnell

d) Yes

Witness) Kiah Harris, Burns and McDonnell

e) The response was misstated and should have read...Ratepayer Impact Measure (RIM test)...and...Ratepayer Impact Measure (RIM)...

Witness) Kiah Harris, Burns and McDonnell

f) Big Rivers decisions on DSM are based on the 1995 R.W. Beck study which used TRC and RIM tests.

Witness) Kiah Harris, Burns and McDonnell

g) Yes, that is why the TRC was used to evaluate the options.

Witness) Kiah Harris, Burns and McDonnell

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
SECOND REQUEST FOR INFORMATION OF JULY 13, 2000

CASE NO. 99-429

Item 6) Follow-up to KDOE Item 21, 1st set:

a. Approximately how much of the $21 million projected for transmission improvements by the Long Range Engineering Plan for 1995-2015 remains to be invested during the period 2000-2015?

b. Approximately how much additional investment will be required for distribution (not transmission) system upgrades during the period 2000-2015?

c. Approximately how much investment (transmission and distribution) will be required for the "improvements projected and contingent upon load growth predicted in Big Rivers' Power Requirements Study" during the period 2000-2015?

Response) a-c The Long Range Engineering Plan was prepared in 1994 based on information in hand at the time and has recently been updated. The current estimate of transmission expenditures for the years 2000-2015 is approximately $67 million. Big Rivers has no distribution system. Consequently, the transmission only expenditures is estimated to be $67 million.

Witness) Travis Housley

7

Item 7) Follow-up to KDOE Item 22, 1st set: The response indicates little if any interest by Big Rivers in investigating the potential benefits of local integrated resource planning (LIRP). In view of the highly positive financial results obtained by other utility companies through their use of LIRP, please explain why Big Rivers and its member cooperatives would not be keenly interested in exploring potential new ways to reduce projected utility costs related to their transmission and distribution systems.

Response) The assessment and interpretation of Big Rivers' previous response to the Kentucky Division of Energy's First Request for Information, Item 22 is incorrect. Big Rivers' response merely indicate that it has not used LIRP and presently has no plans to use LIRP. Big Rivers and its member cooperatives are always interested in exploring new ways to reduce utility costs.

Witness) Bill Yeary

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF	**)**	
BIG RIVERS ELECTRIC CORPORATION	**)**	**Case No. 99-429**

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL'S
SECOND REQUEST FOR INFORMATION OF
JULY 18, 2000

Items 1-12

August 18, 2000

1

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL'S
SECOND REQUEST FOR INFORMATION OF JULY 18, 2000

CASE NO. 99-429

Item 1) Follow-up to Item 1. The IRP mentioned that the Willamette generator would be available in 2001. Please provide the current status of the project, and whether the project is on-schedule to be completed by the date mentioned in the 1999 IRP.

Response) Please see response to Item 9 of the Commission Staff's Second Request For Information.

Witness) Bill Yeary

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL'S
SECOND REQUEST FOR INFORMATION OF JULY 18, 2000

CASE NO. 99-429

Item 2) Follow-up to Item 2c. This response contained "Gross Revenue ($/MWH)" figures for 2000 and beyond that were substantially higher than the gross revenues in response 2b of $42.2/MWH in 1998 and $37.2/MWH in 1999. Please explain in detail the basis for the projections in 2c, and why they are so much higher than the actual revenues received in recent years?

Response) Big Rivers' response to Item 2c of the Attorney General's Initial Request for Information stated that "the gross revenue reflected in the IRP is very aggressive". The footnote in the IRP following each Cost Summary Table for all cases with sales of surplus capacity indicated that the projected revenues were aggressive. The revenue from future sales was projected using the average settle prices for the day in the "into" TVA hub. The revenues projected assume that Big Rivers will obtain this average price for their sales. To the extent that Big Rivers is unable to achieve the average price per MWh, the amount of MWh available for sale is less, or the average market price declines, then the revenue projections assumed in the 1999 IRP will be higher than actually obtained.

"Gross Revenue ($/MWH)" were lower than the projections in the IRP. In order to be conservative Big Rivers believes that it should forward sell a portion of its capacity in the market and leave enough capacity to participate in the next day market. Early in 1999, Big Rivers forward sold a portion of its surplus capacity for the summer months and had planned to sell the remaining capacity in the next day market. Big Rivers ability to participate in the next day market was effectively removed by an obligation to sell 65 MW of capacity. Big Rivers pre-sold 45 MW firm and 20 MW interruptible.

Consequently, the projections in the IRP are aggressive and contain revenues higher than the actual revenues received in recent years. The Risk Assessment Section, Part VI, of the IRP indicates that a 20% variation of the market price does not change the preferred option.

Witness) Kiah Harris, Burns & McDonnell and C. William Blackburn

3

Item 3) Follow-up to Item 2. This response shows actual and projected revenues from arbitrage sales prior to 2011, that were not contained in the Workout Plan. With respect to these unplanned revenues:

a) Will these revenues be used to help repay Big Rivers' debt? If so, please provide any projections of how this revenue stream will move forward the date by which Big Rivers is expected to have repaid its debts.

b) The Workout Plan contained a projected rate increase to member coops within the first 10 years. Will these revenues be used to minimize or eliminate the need for this rate increase? If so, please provide an updated projection on the timing and amount of any proposed rate increase.

Response) a) Yes. Big Rivers' current projection is that the New RUS Note will be repaid in April of 2022. This projection includes a revised estimate of arbitrage/other sales, the defeased sale-leaseback, sales to members, NO_x compliance, and contains no member rate increase. The Workout Plan required the New RUS Note to be repaid in October 2022, included a rate increase, and did not include NO_x compliance.

b) Yes. Please see the response to Item 3a above.

Witness) Mark A. Hite

4

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL'S
SECOND REQUEST FOR INFORMATION OF JULY 18, 2000

CASE NO. 99-429

Item 4) Follow-up to Item 3. This response shows actual and projected sales to members in the IRP substantially above those contained in the Workout Plan. These additional sales should provide Big Rivers with revenues beyond those projected in the Workout Plan. With respect to these unplanned revenues:

a) Will these revenues be used to help repay Big Rivers' debt? If so, please provide any projections of how this revenue stream will move forward the date by which Big Rivers is expected to have repaid its debts.

b) The Workout Plan contained a projected rate increase to member coops within the first 10 years. Will these revenues be used to minimize or eliminate the need for this rate increase? If so, please provide an updated projection on the timing and amount of any proposed rate increase.

Response) a-b) Yes. Please see the response to Item 3a of the Attorney General's Second Request for Information of July 18, 2000.

Witness) Mark A. Hite

5

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL
SECOND REQUEST FOR INFORMATION OF JULY 18, 2000

CASE NO. 99-429

Item 5) Follow-up to Item 5. What has Big Rivers or the three coops done to inform coop members that Big Rivers will look favorably toward distributive generation and will work with members considering such generation?

Response) Big Rivers and its member cooperatives have had discussions with large industrial customers concerning distributive generation. An article explaining some of the potential benefits of customer owned generation will be included in the next Commercial & Industrial News publication. However, the most effective way to inform members of Big Rivers' interest in distributive generation are news releases such as the one announcing the Willamette generator. For convenience, attached is a copy of the Willamette generator news release.

Witness) C. William Blackburn and Russ Pogue

Front Page

Site Menu

Messeng On-Line

c Toolbar--Text Links Below

Willamette to generate its power

Paper mill to harness steam used by plant

1 December 1999

By Steve Vied
Messenger-Inquirer

The Willamette Industries plant near Hawesville produces a staggering amount of paper product every day, 1,400 tons of white paper alone. But soon the massive pulp mill will begin producing something else -- electricity.

To produce the heat energy needed for steam to process wood pulp and dry sheet paper, Willamette burns hundreds of tons of mostly waste wood product, such as sawdust and bark, which is brought in by the truckload.

But before that steam is used in the paper making process, it can be used to produce electricity by turning a generator. Many paper mills do just that. At present, however, Willamette does not.

Willamette plant manager Michael Maloney said this week the company intends to install a 60 megawatt steam-powered electric turbine

Related Links
* Obituaries
* Records

Kentucky:
* Daviess County
* Hancock County
* McLean County
* Muhlenberg County
* Ohio County

Indiana:
* Perry County
* Spencer County

Columnists:
* Dan Heckel
* Keith Lawrence
* Lora Wimsatt

generator at the plant. That is enough power to satisfy about three-quarters of the plant's daily electricity needs. The plant will continue to purchase the rest from Kenergy, formed earlier this year by the merger of Green River Electric Corp. and Henderson Union Electric Cooperative.

The decision to spend upwards of $35 million to produce its own electricity wasn't easy, Maloney said, mainly because electricity in Kentucky is relatively inexpensive. It will also mean that the plant will need to burn a great deal more waste wood.

"We're basically trying to meet some of our own needs," Maloney said. "We're not an electric utility, we're paper makers. Our big focus will be to make paper."

The opportunity to produce its own electricity presented itself as a result of the plant's $600 million expansion two years ago. A third large boiler, fired with "hog fuel" was added, greatly increasing the plant's paper-making capacity. But it also opened the door to producing electricity, Maloney said.

Hog fuel, also known as bio-fuel, is the bark, sawdust, trimmings and tree tops that make up the waste product of sawmills. After the electric generator is added, the plant will burn an additional 916 tons of hog fuel a day.

Willamette's board of directors has approved the funds for the steam turbine generator project and Hancock Fiscal Court recently approved the use of $35 million of the $600 million bond issue it obtained on the company's behalf. Construction will begin early next year and should take about 16 months to complete, Maloney said. The turbine generator will have to be specially made for the project.

Maloney has worked for three other paper mills that produced electricity as a byproduct of its steam generation.

"It's pretty good for cogeneration," he said.

The impact on employment won't be great, Maloney said. The plant already employs people to monitor and operate boilers, he said.

Willamette environmental manager Dennis Waldroup said one reason the company decided to add an electric generator was the desire to control its own destiny. By producing most of the electricity it needs, the plant won't have to worry about interruptions to its power supply. On top of that, Waldroup said, burning hog fuel is a good way to help sawmills dispose of waste.

Willamette is one of Kenergy's largest customers and the paper mill's generator project is sure to have an impact on the cooperative. However, Kenergy officials were attending a company retreat Tuesday and were not available for comment.

Steve Vied, (270) 691-7305
sVied@messenger-inquirer.com

* Back to Top

* Send a letter to the editor
Toolbar--Text Links Below

Send your comments or suggestions about local news coverage to news@messenger-inquirer.com

Home Front Page | Kentucky | Indiana | Sports | Opinion | Columnists | Community | Perspective | Business | Agriculture | Education Religion & Values | Your Health | Good Times | Lifestyle |

6

CASE NO. 99-429

Item 6) Follow-up to Item 6. What is Big Rivers' definition of "feasible and viable"? Are distributive generation projects evaluated against Big Rivers' avoided costs of under 20 mils, or the three coops' avoided costs of 30.47 mils for large industrial or 36.44 mils for residential customers?

Response) The response to Item 6 of the initial request uses the terms "feasible" and "viable" in referring to the options to meet Big Rivers' future power requirements. A feasible option must be one that is capable, financially and physically, of being completed by someone else and meeting Big Rivers' objective of increasing its electrical capacity. The option must be viable in the sense that Big Rivers must be assured that someone else will be committed to sustaining their project to allow Big Rivers to include that project in its Power Supply mix.

Big Rivers will consider distributive generation projects and the appropriate avoided cost to be utilized for evaluation purposes on a case-by-case basis.

Witness) Bill Yeary

7

CASE NO. 99-429

Item 7) Follow-up to Item 7. Why would run-of-river hydro with a capacity factor of 60% be considered too high of a load factor to be considered at this time, while biomass with capacity factors in the 80% to 90% range is not considered too high a load factor to consider now?

Response) Bio-mass was discarded as an option during the screening analysis of the planning effort and therefore did not receive much more attention than a run-of-the-river hydro option. Nevertheless, since Big Rivers is not in need of a high capacity factor energy resource at this time, neither the bio-mass nor the run-of-the-river alternatives are attractive to Big Rivers at this time.

Witness) Kiah Harris, Burns & McDonnell

8

Manufactured by
JULIUS BLUMBERG,
NYC 10013
PRODUCT NO. 510

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL'S
SECOND REQUEST FOR INFORMATION OF JULY 18, 2000

CASE NO. 99-429

Item 8) Follow-up to Item 8. Please provide a comparison of biomass fuel costs for plantation grown trees versus locally available wood-waste such as sawdust from area sawmills.

Response) Time does not allow a detailed comparison of the locally available wood-waste versus plantation grown biomass specific to Big Rivers' service area. However, the TVA, through the Oak Ridge National Laboratories, has prepared extensive analysis of woody crops for use as a biomass fuel from farmers in the Tennessee area. The papers can be found at the following ORNL web sites: http://bioenergy.ornl.gov/papers/bioam95/graham2.html and http://bioenergy.ornl.gov/reports/tvareg/supply3.html. It should be considered in reading these papers that it takes approximately 600 tons per day to operate a 20 MW power plant fueled with wood and that transportation costs have to be included. Results of the study conclude that wood waste fuel is available in the range of $2.50 per MBtu at the farmgate. This translates into approximately $0.037 per kWh without transportation. Waste fuel can be priced anywhere from $0 per MBtu on up. The pricing of waste products is usually indexed to some other fuel, such as coal. Case studies of two waste wood fueled power projects in the Northwest and Michigan show waste fuel energy prices of $0.0122 per kWh (Northwest 1989 prices) and $0.0175 per kWh (Michigan 1989 prices). The complete paper for these studies can be found at http://www.ee.umr.edu/areas/power/Energy_Course/energy/profiles.html. However, fuel cost is not the issue with this alternative, since Big Rivers is not in need of significant amounts of energy. It is the capital cost of the facility that makes it unattractive, being in excess of $1800 per kW.

Witness) Kiah Harris, Burns & McDonnell

9

Item 9) Follow-up to Item 9. The R.W. Beck study was done in 1995, before the restructuring of Big Rivers, and thus contains system related costs that are no longer appropriate. Has Big Rivers made any attempt to update the R.W. Beck study with updated post-restructuring costs?

Response) No, not at this time.

Witness) C. William Blackburn

10

Item 10) Follow-up to PSC Item 5, page 7 of 9. This response states that strategic conservation will have a negative financial impact on Big Rivers and cause member rates to rise.

a) Please provide a detailed explanation of how lost sales to distributive generation, which Big Rivers is encouraging, is any different that lost sales due to strategic conservation.

b) Big Rivers' response to the Attorney General's Request, Item 2, shows present and projected revenues from sales of surplus energy at a price above the 33.78 mils Big Rivers receives from member coops. Please explain why strategic conservation is not a win-win concept, since members can reduce their bills and Big Rivers can receive more revenues than it would selling this surplus energy to members (and reducing the need for new capacity also).

Response) a) The distributed generation contemplated in the IRP would be in use only during peak times when the maximum advantage could be taken in reducing peak demand by a verifiable amount and taking advantage of the anomalies in the current market where wholesale energy can be priced at a higher amount than retail energy during certain hours and savings passed on to the consumer, similar to the recommended C/I load management program. When the cost of wholesale energy dropped below the retail, then the distributed generation would be turned off and energy would be taken from Big Rivers. Strategic conservation does not typically allow such a sculpting of the use of the energy to be developed since it is in effect all of the time. Since it reduces the energy sold when wholesale energy is lower cost than retail, it reduces the units of energy over which fixed costs and margins are collected, putting pressure on rates.

b) Strategic conservation cannot be turned on and off in response to the pricing anomalies in the wholesale market.

Witness) Kiah Harris, Burns & McDonnell

11

Item 11) Follow-up to DOE Item 7. This response states that renewables are not commercially viable today.

a) Please provide all studies that back-up this claim.

b) Please provide the retail rate levels being paid to each of the three coops by both residential and industrial members, against which the viability of renewable resources would be measured.

Response) a) In the context of this study, commercial viability means that a product is widely available to the general sector in which it would be applied, stands on its own from the standpoint of any government incentives, and is economically attractive to the purchaser on Big Rivers' system when compared to other alternatives. Although it is not possible in the time frame for a response to these questions to provide all of the studies to back up the claim made in the above referenced response, following are excerpts from industry web sites and other papers discussing renewables and fuel cells.

Fuel Cells: Plug Power is a fuel cell consortium including General Electric to tap the residential and small commercial market. It estimates that a commercially available (not necessarily viable) unit is at least a year away. From its web site at http://www.plugpower.com/product/ "Fuel cells generate power directly where it is used – avoiding the losses associated with transmitting electricity great distances. Plus Power's residential fuel cells will be available in 2001 through GE" MicroGen.

From the Fuel Cell Commercialization Group at http://www.ttcorp.com/fccg/ "The FCCG is working exclusively with Fuel Cell Energy, Inc.[formerly Energy Research Corporation] to design a multimegawatt carbonate fuel cell power plant that meets utilities' needs for a commercial product that will be available in the year 2002. FCCG members provide FCE with product definition, information exchange, and other market feedback critical to the commercialization process, and will purchase the first fuel cell power plants produced by FCE."

From the small commercialization group's site at http://www.nfcrc.uci.edu/fuelcellinfo_index.htm "Small-Scale Fuel Cell Commercialization Group, Inc. The purpose of the Small-Scale Fuel Cell Group (SFCCG,Inc.) is to promote the commercialization of MARKETABLE residential, small commercial and small industrial fuel cells.

The purpose of this web site is to inform members of the SPCCG, fuel cell manufacturers and the fuel cell community of advances in the commercialization of small fuel cells."

(See spreadsheet model next page)

From a spreadsheet model in the site, "Costs to Generate Electricity Using Fuel Cells", the following costs were presented by the group.

	Natural Gas	Propane	Methanol
Capital Cost	$3,167	$3,167	$3,167
Year Annual Costs	$651.32	$651.32	$651.32
Life (in years)	7.3	7.3	7.3
Salvage Value	$166.67	$166.67	$166.67
Unit Size kW	3.3	3.3	3.3
KWh Capacity (Annual)	29,200	29,200	29,200
Load Factor	73%	73%	73%
Annual kWh	21,413	21,413	21,413
Annual O&M	$366.67	$366.67	$366.67
Efficiency (fuel in, electricity out)	48%	50%	50%
Fuel Cost	$3.25	$0.83	$0.50
Fuel Cost Units	$/MCF	$/gallon	$/gallon
WACC before taxes	11%	11%	11%
Fuel Cost per kWh	$0.0229	$0.0622	$0.0570
Capital Cost per kWh	$0.0304	$0.0304	$0.0304
O&M Cost per kWh	$0.0171	$0.0171	$0.0171
Average Cost per kWh	$0.070	$0.110	$0.105

In review of the table, typical estimates for annual load factors for residential customers are more in the range of 30% to 50%. Dropping the load factor to 50% increases the average cost for natural gas fueled units, the lowest cost energy, to $0.0923 per kWh.

Photovoltaics

The Utility Photo voltaic Group is a group dedicated to the promotion of solar PV applications. From their website, http://ttcorp.com/upvg/faq_hoff.htm. a discussion with Tom Hoff about a report he prepared entitled "An Historic Opportunity for Photovoltaics and Other Distributed Resources in Rural Electric Cooperatives (Thomas E. Hoff, Clean Power Research/Matt Cheney, UPVG, 1999) provides some insight to the commercial viability of PV. An excerpt from the discussion:

"UPVG: The numbers that jump out of the report are the potential size of the market for PV – 500 to 950 Megawatts – and the potential cost savings for co-op utilities - $1 billion to $2.5 billion. But these numbers have to be understood in context. First, these numbers could not be achieved today. Hoff: That's right. This market size is predicated on a PV system cost of $3,000 per kilowatt. That's about half of the very lowest cost PV system you can buy today. I cannot predict exactly when we can expect to see PV reach that threshold price."

Wind

Bergey Wind Power is one of the largest producers of home style wind packages in the world A review of their web site at http://www.bergey.com/provides the following information:

"Here's a quick test on wind power feasibility, assuming you don't live in a state with a subsidy program and you want to recoup your investment in 15 years or less. Given these conditions, you should consider wind power if:

1) Your electricity costs more than 11 cents per Kilowatt-hour (kWh.
2) Your area has an average wind speed of 11 miles-per-hour (MPH) or more, and,
3) You have (1) acre of property or more.

Information from their site provides an approximate cost for an installed 10kW unit sold for "Utility Bill Reduction Value Package" to be approximately $30,000 or $3,000 per kW. A wind map of Kentucky produced by the DOE shows the Big Rivers area to be in a class 1 wind area, which means the wind blows between 0 and 9.8 mph on average, below the speed recommended by one of the world's leaders in sales of small wind packages.

From the above brief information, we continue to conclude that the technologies contemplated by the net metering policies are not presently commercially viable in the Big Rivers' area.

b) The retail rate of each of Big Rivers' three member distribution cooperatives is available on the Kentucky Public Service Commission's web site.

Witness) Kiah Harris, Burns & McDonnell

12

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL'S
SECOND REQUEST FOR INFORMATION OF JULY 18, 2000

CASE NO. 99-429

Item 12) Follow-up to DOE Item 19b. This response states that these DSM options scored poorly on the RIM test. In generating these poor RIM results, did Big Rivers factor in the fact that any energy saved could be sold off-system at a large margin such as those included in Big Rivers' response to the Attorney General's request, Item 2c, where selling this energy off-system can actually be a net benefit to ratepayers?

Response) Big Rivers' response does not state that "…these DSM options scored poorly on the RIM test." Since we are not certain what is meant by this paraphrasing of our response, we have limited our response to confirm that the DSM options which were carried into the analysis with the supply-side options in the IRP included off-system sales revenue.

Witness) Kiah Harris
Burns & McDonnell

Big Rivers
Electric Corporation

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
502-827-2561
www.bigrivers.com

August 17, 2000

AUG 18 2000

Mr. Bill Bowker
Acting Executive Director
Kentucky Public Service Commission
P. O. Box 615
Frankfort, KY 40602-0615

RE: Integrated Resource Plan of Big Rivers Electric Corporation,
PSC Case No. 99-429

Dear Mr. Bowker:

Big Rivers wants to call attention to the fact that the witness for Burns & McDonnell has changed. This change is due to staff changes at Burns & McDonnell. Enclosed are an original and six (6) copies of the letter from Burns & McDonnell reflecting the organizational changes and the resume of the current witness.

I certify that a copy of this letter and enclosures has been served by mail, postage prepaid, on each of the persons identified on the enclosed service list.

Sincerely yours,

BIG RIVERS ELECTRIC CORPORATION

David A. Spainhoward

David A. Spainhoward
Vice President of Contract Administration
and Regulatory Affairs

pm
Enclosures

SERVICE LIST
CASE NO. 99-429

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

Office of the Attorney General of the Commonwealth of Kentucky

John Stapleton
Director of Energy
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Hon. Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Counsel for Natural Resources and Enviromental Protection

Burns & McDonnell
SINCE 1898

RECEIVED
AUG 7 2000

August 3, 2000

Mr. Bill Yeary
Big Rivers Electric Corporation
201 Third Street
PO Box 24
Henderson, KY 42419-0024

Staff Assignments
1999 IRP

Dear Mr. Yeary:

The preparation of the 1999 Integrated Resource Planning Study by Burns & McDonnell for Big Rivers has involved several members of our staff. During the last two months, we have had two of our staff, Mr. James Flucke and Mr. Armando de Leon, leave Burns & McDonnell for other employment. Mr. Flucke served as the Project Manager for the project and Mr. De Leon was the lead analyst on the demand side management portion of the study.

With the departure of Mr. Flucke and Mr. De Leon, responsibility for the project has transferred to Mr. Kiah Harris. Mr. Harris is a Principal in the Management Services Group and has been with Burns & McDonnell for over 20 years. We have attached a copy of his resume for your files. Mr. Harris has analyzed numerous utility systems for supply and demand side resource alternatives. Mr. Harris has assisted in the response to the various questions received on the IRP and will be available on an on-going basis to assist you in responding to the various inquiries you may have about the study.

We apologize for any inconvenience this change in staff may have caused and wish to confirm our continued support of Big Rivers through the completion of this process.

Sincerely,
BURNS & MCDONNELL

Mr. David E. Christianson
Vice President
Management Services Group

Encl:

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690
www.burnsmcd.com

Kiah E. Harris, P.E.

Expertise:

Utility Economics
Integrated Resource Planning
Generation Planning and Design
Transmission Planning and Design
Power Pool Dispatching/Interchange Cost Analysis
Contract Negotiations
Strategic Planning

Education:

B.S. in Electrical Engineering, University of Missouri, 1972
M.S. in Electrical Engineering, University of Missouri, 1975

Organizations:

Institute of Electrical and Electronics Engineers, Power Engineering Society
Eta Kappa Nu

Registration:

Professional Engineer - Colorado, Washington, Wisconsin, Nebraska, Louisiana

Mr. Harris joined Burns & McDonnell in 1980 and has been manager of the Management Services Group since 1988. This division is responsible for providing strategic utility planning studies for domestic and international utility management. Services from the division include analysis of rates, forecasting, contract negotiation, transmission and power supply planning, and organizational and market competition assessments.

Mr. Harris' experience has provided detailed knowledge in the planning, engineering, financial and policy issues associated with the expansion and operation of power systems. He has worked on numerous assignments in the expansion of the generation and transmission systems in the uncertainty of privatization and deregulation futures. These assignments have brought significant understanding of the impacts policies have on the investment decisions and the risks involved in the current environment.

Mr. Harris is providing consultation to numerous utilities and independent power producers. This consultation includes the following areas:

- Power Supply Acquisition and Management
- Project Feasibility
  - Generation
  - Transmission
- Strategic Planning
  - New Business Ventures
  - Existing Operations
  - Retail Choice
- Transmission Planning and Operation
- Contract Negotiations
  - Power Purchase
  - Asset Purchase/Sale
  - Interconnection Agreements
- Support for Acquisition of Financing
- Utility Policy & Restructuring Issues
  - Domestic
  - International
- Power System Operation & Economics
- Cost/Rate Analysis

Kiah E. Harris, P.E.

(continued)

Mr. Harris serves as a company consultant for transmission system studies such as short circuit, power flow, stability and harmonics. He has performed studies for systems with voltage levels up to 500 kV. He managed a major study for several utilities on joint operation of a large, multi-terminal HVDC transmission project in the U.S. Mr. Harris has assisted in development and review of numerous contracts for utility interconnection and power supply arrangements. Mr. Harris has provided training to in-house staff, clients and MultiAmp Institute courses on relaying, symmetrical components and transmission planning/interconnections.

From 1980 to 1988, Mr. Harris served in the power applications section of the Electrical Department. He was chief of the section from 1984 to 1988. He has participated in numerous generation and substation development projects through the development of one lines, control schematics and wiring diagrams, equipment specifications, and final testing and checkout. These projects have included pulverized and fluidized bed coal, gas, geothermal, diesel and hydro generating plants ranging in size from 750 kW to 735 MW. He has developed dispatch systems for numerous utilities for the scheduling and dispatch of their systems.

Technical Publications/Presentations:

"Utility Interconnection Course-Technical, Economic and Policy Issues", Harris, Kiah, Power-Gen Asia Seminar, Bangkok, Thailand, September 19, 2000.

"Adding Generation in Today's World," Harris, Kiah, Electric System Reliability Conference, Denver, CO, November 10, 1999

"Private Use Restrictions and Their Impacts," Harris, Kiah, Iowa Association of Municipal Utilities, Oct. 1999.

"Financial Modeling of Power Supply Offers," Harris, Kiah, APPA, Albuquerque, NM, Sep, 1999.

“More Thoughts on Wild Prices,” Harris, Kiah, Ensuring Reliability for Competitive Power Conference, Dec. 7, 1998

“Financial Modeling of Power Supply Offers,” Harris, Kiah, APPA, St. Louis Oct, 1998

“Thoughts on Wild Prices” Harris, Kiah, American Public Power Association, 1998

“Life after FERC Order 888 & 889” Harris, Kiah; American Public Power Association, 1998

“Seminar on Industry Restructuring and Deregulation,” Harris, Kiah, DeLeon, Armando City Public Service, San Antonio TX, 1997

Kiah E. Harris, P.E.

(continued)

"What Are We Headed Towards/Retail Restructuring Issues," Harris, Kiah, Missouri Association of Municipal Utilities Annual meeting, 1997.

"IPP Project Appraisal and Evaluation," co-presenter of two-day workshop, Center for Financial Engineering and Development, WADC, 1996.

"Power Supply Primer," Harris, Kiah; May, Mike. American Public Power Association, 1994.

"IPP Opportunities with Municipal Utilities," Harris, Kiah. Cogeneration Conference, 1994.

"Integrated Resource Planning," Harris, Kiah. Kansas Municipal Energy Agency, April 1991.

"The Clean Air Act Amendments Impact on Municipal Utilities." Harris, Kiah. Florida Municipal Electric Association, June 1991.

"Least Cost Planning - Supply-Side Considerations," Harris, Kiah. NRECA Annual Meeting, Manager's Session, 1990.

"Key Issues Affecting Future Electric Power Supply in the United States,"Harris, Kiah; Campbell, Newton. World Electricity Conference of the Financial Times, November 1990.

"Clean Air Act Impacts on Utilities - System Planning," Harris, Kiah. American Public Power Association, December 4-5, 1990.

"Cycling Programs - Getting on the Fast Track," Harris, Kiah. Texas Public Power Association. July 1989.

"Practical Applications of Demand Side Management," Harris, Kiah. Forecasting Methods and Issues Seminar, September 1988.

"Symmetrical Components and Protective Relaying," Harris, Kiah. Multi-Amp Institute. Dallas, Texas, 1986, 1987.

"Electrical Analysis of Cogeneration Systems and Interconnections - System Studies and Interconnections," Harris, Kiah. Burns & McDonnell, March 11-12, 1986.

"System Protection and Analysis," Harris, Kiah; Werthman, Jack. Deseret G&T, 1981.

"Test Results of 345-kV Mead-Liberty Staged Fault Tests," Eilts, Larry; Harris, Kiah. Western Area Power Administration, 1977.

Task Force Membership:

Consumer Energy Council of America "Transmission Planning, Siting and Certification in the 1990s: Problems, Prospects & Policies." - 1990.

National Rural Electric Cooperative Association "Least Cost Planning" - 1991.

Kiah E. Harris, P.E.

Representative experience since 1988 for Mr. Harris includes:

Georgia Transmission Company 2000

Analyst on project to develop ten year transmission plan for the Georgia Transmission Company, a transmission company which serves approximately 8000MW in the state. Planning from the 500kV level to distribution delivery point voltages.

Aquila 2000

Advisor to Aquila on interconnection process and agreement terms and conditions for projects in MAIN and SERC. Reviewed interconnection agreements and upgrade requirements from utilities for connection of the proposed projects.

Tennergy Corporation 2000

Advisor to the Tennergy Corporation on the development of generation projects for the TVA. Created proforma results with a variety of revenue and expense projections. Worked with financial advisors to create offers and negotiate the power purchase agreement terms.

North American Power Group 1999-present

Project manager for the analysis of transmission improvements needed to deliver additional power out of the Powder River Basin in Wyoming. Steady state load flow, dynamic stability and modeling of solid state devices to improve operation of the existing system. Used numerous WSCC models in analysis.

Minnkota Power Cooperative 1999

Consulted with the utility on losses associated with various transmission agreements entered into with other utilities. Identified areas where the utility could pursue modifying the way the losses were treated.

Rochester Municipal Utilities 1999-Present

Project manager for an assessment of various generation options to be installed on existing sites in the service territory. Analyzed MAPP area market, transmission limitations and supplier rates. Generation options included considerations of future repowering of existing steam facilities. Served as advisor on the bond financing and developed the proforma operating results.

Commonwealth Utilities Commission of Saipan 1999-present

Project manager for the evaluation of privatization of 80 MW of electrical generation, and substations and transmission lines for the island. Developed the draft power purchase agreement and bid documents for the RFP. Directed the technical and economic evaluation of the offers. Currently evaluating the size of project warranted in the face of a declining economy and risk of substantial load loss.

Hoosier Electric Power Cooperative 1999-present

Kiah E. Harris, P.E.

(continued)

Consultation on the analysis of transmission impacts for the addition of various levels of merchant gas-fired generation on the Hoosier system and surrounding utilities. Performed load flow analysis and reviewed work of Hoosier staff. Developed range of impacts and cost estimates for upgrades. Performed dynamic stability analysis of the generation option selected.

Corn Belt Power Cooperative 1999-present

Project manager for a power supply study for Corn Belt which included assessment of the lowest cost option for meeting future power supply requirements. Options included purchases, installed generation and repowering of an existing 37MW coal fired power plant. Project required a review of the MAPP market of purchases and the transmission system limitations for delivery. The study also assessed the potential benefits of distributed generation. Developed further design details for evaluation of the repowering which led to determination of a more effective repower option. Analyzed the MAPP issues associated in connecting the project and its impact on the distribution factors across constrained interfaces in MAPP.

Private IPP Client 1999

Reviewed the transmission interconnection and facilities agreements for connection of a 500MW merchant plant to the grid in the MAIN area to determine the exposure the IPP had to future transmission modification costs.

Springfield Municipal Utilities 1994-1995, 1999-2000

Project manager for power supply assessment of participating in various proposed generating units from IPPs and EWGs.

- Prepared load forecast
- Analyzed production cost of options
- Retail wheeling assessment
- Reviewed transmission delivery paths
- Assessment of utility privatization
- Valuation of assets.

National Rural Electric Cooperative Association 1998

Consultant on Promotion of Global Climate Challenge program to municipal utilities

South Mississippi Electric Power Association 1998

Project Manager on a stability study for the addition of a new generating unit at an existing Powerplant.

Electroambato 1998

Project Manager for a feasibility study for a 30 mw power plant in Ecuador.

Kiah E. Harris, P.E.

(continued)

- Interconnection load flow short circuit and stability analysis.
- EPC contract development
- Environmental impact statement
- Financial assessment

Gateway Energy 1998

Assisted IPP in development of proposal on 400 MW cogeneration project

- Interconnection layout
- Proforma
- Energy Marketing Potential

Freehold-Board of Public Utilities- New Jersey 1998

Project manager for assessment of utility buyout of cogeneration contract for the PUC.

Marubeni/NPPD 1997-1998, 1999

Performed review as Owner's Engineer for peat plant in Ireland of the Power Purchase Agreement, Fuel Supply and Transmission/Interconnection contracts. Consulted on participation in a Powder River Basin Power Project.

Manager for the development of a feasibility study for a 250MW combined cycle plant in Brazil. Developed the proforma operating results and prepared the report to describe engineering, environmental, financial and operating issues to the host government.

Central Louisiana Electric Company 1997

Consulted CLECO on various issues

- Cogeneration project for customer
- Strategic planning on non-regulated business
- Contract development

Missouri Association of Municipal Utilities 1997

Project manager for deregulation study which reviewed

- Stranded cost impacts
- Tax impacts
- Payment in lieu of taxes

COHDESA 1996-present

Consultant on development of IPP biomass project in Honduras.

- Consulted on unit sizing and market pricing
- Developed power purchase agreement

Kiah E. Harris, P.E.

(continued)

Zambian Privatization Agency 1996-1997

Project manager for feasibility study on the Kafue Gorge Lower 600-MW Hydro Electric project.

- Prepared Pro formas
- Analyzed Technical Feasibility
- Analyzed Market
- Analyzed Transmission System for delivery

Colorado River Commission 1996

- Consultant on major transmission upgrade project for water pumping system
- Directed load flow analysis on 230 kV and 69 kV options for 600 MW load
- Analyzed transmission options for different rights-of-way

Private Client 1996

Review of contract for steam and electric facility in Czech Republic.

- Steam sale agreement
- Coal purchase agreement

Sikeston, Missouri 1995-1998

Consultant to the utility on numerous issues including

- Transmission studies
- Outage reduction
- Standby power contracts
- Fuel switching study
- Power pooling participation

SEMO 1995-1997

Lead developer for a 400 MW coal-fired power plant as a second unit to existing site. Activities included:

- Negotiate development agreement
- Negotiate O&M, construction and joint facilities agreements
- Assess transmission impacts with interconnected utilities
- Project manager on load flow studies for entire Honduran transmission system.
- Assisted in negotiation of contracts for interconnection with Western

Area Power Administration

Tennessee Valley Public Power — 1995, 1996, 1998, 1999

Project manager for analysis of:

- TVA Integrated Resource Plan
- TVA competitive position and distribution alternatives
- Member distributor viewpoint of removal of restrictions on sales outside current territory
- Analyzed transmission transfer capacity
- Transmission Tariffs and Ancillary Rates
- TVA/District Power Supply Contracts

MAPLLC — 1994-Present

- Consultant on IPP project in Wisconsin
- Analyzed transmission access and improvements for 300 MW combined cycle plant
- Negotiated transmission agreements
- Assessed interface constraints between MAPP and MAIN reliability region
- Negotiated plant purchase agreement

Heard Energy (IPP) — 1994

Project manager on analysis of feasibility of coal-fired units in Indonesia. Included:

- Load growth assessment
- Economic impact on energy costs
- Unit sizing and dispatch concerns

Ottawa, Kansas — 1994

Project manager for electric master plan study. Included:

- Load forecast
- Power supply assessment
- Existing unit life extension
- Transmission and distribution assessment

St. Joseph Light and Power — 1994

Project manager for unit commitment study, which included evaluation of build options, IPP proposals and participation in common units.

Energia de Nuevo Leon (Mexican IPP) 1993-1994
Project consultant on 250-MW IPP project in Mexico.

- Developed load projections
- Prepared cost of energy projections
- Identified options for load shifting
- Assessed transmission system for plant interconnection

Integrated Resources (IPP) 1993
Project manager for:

- Proposal on combined cycle repowering to Midwest utility
- Plant valuation
- Economic analysis and pro formas

Cooperative Power Association 1993
Project manager for:

- Wholesale cost of service study
- Competitive assessment
- Benchmark study
- Rate strategies

Private Interest 1992, 1995
Project manager for IPP Waste-Energy in Pakistan.

- Fuel contract negotiation
- Technical consultation
- Financial consultation

Private Industrial Client 1992, 1995
Project manager for cogeneration consulting.

- Steam purchase agreement
- Transmission interconnection analysis
- Asset valuation
- Sales contract negotiation

Kiah E. Harris, P.E.

(continued)

Cajun Electric 1992, 1994

Project manager for market valuation study for future power and energy sales.

- Transmission agreements
- Contract review
- Unit availability review

Texas Municipal Power Agency 1992, 1993, 1994

Project manager for wholesale rate study and power supply analysis. Included:

- Analysis of fuel switching from lignite to Powder River Basin coal at 400-MW unit
- Analysis of repowering 27 various sizes of steam units to combined cycle (7 MW to 150 MW)
- Analyzed production costs of future power supply alternatives and develop financial requirement

Texas Municipal Power Agency 1992, 1993

- Project manager for IPP cogeneration facility.
- Technical analysis
- Rate of return analysis
- Wholesale rate analysis
- Lower Colorado Power Agency - $991 million
- Lincoln, Nebraska - $92 million
- Snohomish County PUD - $90 million

Private Interest 1992, 1993

- Contract development for power purchase agreement between IPP and foreign government utility
- Rate analysis for proposed agreement
- Plant and HVDC Dispatch issues associated with firm and economy energy sales from two 300-MW plants

City of Ames, Iowa 1991-1992

Project manager for Integrated Resource Planning Study. Reviewed:

- Transmission contracts
- Demand side option

- Refuse derived fuel
- Fluidized bed units
- Combined cycle units
- Clean Air Act impacts

City of Jonesboro, Arkansas 1990-Present
on various projects including:

- Power pool formation
- Transmission and substation planning for 161-kV and 69-kV system
- Power supply analysis
- Contract negotiations
- Testimony on Property Tax on Power Plant
- Purchase for peaking generation installed in city

Tri-County Electric 1990-1993
Project manager for rate work.

- Filed testimony with Texas PUC
- Analyzed transmission costs from wholesale supplier
- Consumer rates

Omaha Public Power District 1989-Present
Project manager for:

- Corporate finance review
- Bond financings of $150 million
- Power supply review

City of College Station, Texas 1989, 1994
Project manager for power supply study, contract review, proposal evaluation of alternative suppliers, power cost projectionand system valuation.

City of Gilbert, Arizona 1989-1991
Project manager for power supply study. Included development of:

- Municipal utility creation
- Transmission wheeling
- Load forecast

Kiah E. Harris, P.E.

(continued)

- Wholesale and retail power cost projections
- Contract review
- System operating cost

City of Plaquemine, Louisiana 1989
Project manager for power supply study, contract review, proposal evaluation of alternative suppliers, power cost projection, and system valuation.

City of Willmar, Minnesota 1989
Project manager for power supply study for city. Included load forecast, proposal evaluation and construction cost estimates for combustion turbines, fluidized bed boilers and life extension. Acid rain allowance evaluation.

Entergy Services 1989
Project consultant on development of unit market valuation study for coal- and gas-fired units.

Bond Financings Managed for Burns & McDonnell 1988-present

- Wisconsin Public Power Inc. - $150 million
- Omaha Public Power District - $1,278 million
- Northern Minnesota Power Agency - $302.7 million
- Rochester Municipal Utilities-$55 million

City of Henderson, Kentucky 1988-Present
Project consultant for:

- Annual budget review
- Biennial bond reports

Snohomish County PUD 1988-1991
Project manager for General Services Agreement. Included:

- Insurance review
- Water study
- Coal-fired power plant clean air impact
- Triennial report
- Bond financing $90 million

Entergy Services 1988-1992
Project manager on development of high-voltage direct current (HVDC) project report covering construction of 1,800 miles of 500 kV HVDC line and 12,000 MW of HVDC converter stations.

- Coordination study on joint operations between four utilities totaling

19,000 MW of capacity

Wisconsin Electric Power Co. 1988

Consultant for protective relay coordination, system switching analysis and var placement for 138-kV transmission lines and substation.

Arizona Electric Power Coop. 1988

Provided transmission planning and load flow data on addition of 230-kV lines to extensive transmission system.

Prior to 1988, Mr. Harris' utility experience included:

City of Columbia, Missouri 1987-Present

Project manager on an Integrated Resource Planning Study. Reviewed:

- Demand side options
- Combined cycle repowering
- Fluidized bed units
- Clean Air Act effects
- Transmission wheeling costs
- Ongoing power supply analysis
- Load flow analysis

Municipal Energy Agency of Nebraska 1987, 1989

Project manager for an Integrated Resource Planning Study. Included:

- End use survey development and tabulation
- Appliance efficiency and installed costs
- Assessment of consumer acceptance
- Wholesale power cost impact
- Transmission coordination
- Integrated control and operations

Mead-Phoenix Transmission System, Arizona 1987

Prepared short circuit studies, device coordination and assisted in staged fault tests for 230-kV/345-kV 150 mile transmission system, which included series compensation, shunt compensation and phase shifting transformers.

Schuylkill Power Plant, Pennsylvania 1987

Designed the auxiliary system and interconnection substation for an 80-MW coal-fired IPP power station. Negotiated interconnection agreement between client and Pennsylvania Power & Light. Developed short circuit study and prepared relay settings for plant and substation.

Imperial Irrigation District, California 1986

Prepared protection schemes for 230-kV/92-kV collector system for IPP geothermal facilities in Southern California. Included five substations and over 100 miles of transmission lines. Analyzed short circuit study for relay settings.

Missouri Municipal Electric Utility Commission 1984-Present

Project manager for organizational study for 1700-MW utility.

- Power supply analysis
- Power purchase and interconnect agreements
- Load forecasts
- Utility/IPP supply alternatives
- Wholesale rates
- Control area services/transmission system use
- Remote metering system

Wisconsin Public Power Inc. System 1984-Present

Project manager for overall engineering, study and environmental services for development of 300 MW+ utility. Involved:

- Transmission coordination
- Environmental siting of a combustion turbine
- Preparation of wholesale cost projections
- Analysis of unit purchase plans for 100-MW coal-fired unit
- Analysis of condition of existing generation
- Engineer's Report for bond financing $150 million
- SCADA/EMS system
- Metering system analysis

Provo, Utah 1984-1988

Development of interconnection and power purchase agreements between Utah Power & Light, Provo and Mother Earth Industries, an IPP geothermal developer in southern Utah

- Prepared load flow analysis of system for transmission planning study
- Designed substation interconnection facilities

Jacksonville Electric Authority 1984-1994

Project manager for annual transmission and distribution report covering

Kiah E. Harris, P.E.

(continued)

planning and construction issues. Developed report for voltage quality program to be considered for implementation.

- Reviewed cogeneration interconnect agreement
- Transmission reliability planning
- System stability studies
- Power quality assessment
- Breaker failure settings
- System load flow

Geneva, Illinois 1984-1991

Prepared power supply study of alternative generation technologies which included methane gas, landfill unit.

- Prepared supervisory control system for efficient control of systems for implementation of power purchase agreement
- Negotiated technical aspects of interconnection and power purchase agreements with Wisconsin Electric Power Company

Chugach Electric Power Coop., Alaska 1983

Power system load flow and reliability assessment for 230-kV, 138-kV and 115-kV transmission system.

Western Farmers Electric Coop., Oklahoma 1982

Relay coordination and settings for 400-MW coal-fired power plant and associated 138-kV/345-kV system. Assisted in electrical start-up and synchronization assistance.

Sunflower Electric Power Coop. 1982

Prepared relay settings for over 300 devices on 345-kV, and 115-kV and 69-kV system. Required analysis of load flow and short circuit studies.

Four County EMC 1981

Prepared equipment specifications, one line, three lines and schematic diagrams for a 230-kV, 69-kV interconnection substation.

Mr. Harris has developed short circuit and relay coordination studies between 1980 and 1988 for:

- New Ulm, Minnesota
- Plaquemine, Louisiana
- Armco Steel, Mexico City, Mexico
- Armco Steel, Ashland, Kentucky
- Sikeston, Missouri

Kiah E. Harris, P.E.

(continued)

- Gillette, Wyoming
- New Smyrna, Florida
- Willmar, Minnesota
- Columbia, Missouri
- Mesa, Arizona
- Lea County, Coop., New Mexico

Mr. Harris has been project manager on Energy Management System Design, Specification and Start-up assistance between 1980 and 1988 for:

- WPPI, Inc. System
- Ames, Iowa
- Independence, Missouri
- Puget Sound Naval Shipyard
- Provo, Utah
- Pedernales Electric Coop.
- Geneva, Illinois
- Gillette, Wyoming
- Kaw Valley Electric
- East River Electric

Deseret Generation and Transmission Coop. 1980-1985

Analyzed short circuit load flow and stability analysis for 345-kV and 115-kV transmission system. Prepared harmonic analysis for single phase railroad. Developed equipment specification, one line, three lines, schematic and relay settings for a 400-MW coal-fired plant and over 300 miles of 345-kV, 115-kV, 69-kV and 12.47-kV system with four major substations, shunt reactors and a single-phase railroad. Directed electrical synchronization effort and substation engergization.

Fort Leavenworth, Kansas 1978

Designed the conversion of 4-kV system to 12.47-kV underground and new 34.5-kV overhead circuits.

Glen Canyon, Arizona 1977

Prepared relay protection scheme and setting for 230-kV phase shifting transformer at the Glen Canyon Power Plant.

Kiah E. Harris, P.E.

(continued)

Stegall, Nebraska 1977

Prepared short circuit and relay coordination analysis for Stegall, Sidney, Gering and Chadron substation 115-kV transmission systems.

Mount Elbert Pump Storage Plant, Colorado 1976

Project engineer on system studies, power house and 230-kV switchyard, one line, three lines and protective device coordination. Resident electrical engineer during construction.

Grand Coulee, Washington 1976

Prepared electrical protection drawings for three 730-MW unit additions to the third power house at Grand Coulee Dam. Developed protection system for the 500-kV cable interconnecting the plant and switchyard.

Keswick Power Plant, California 1975

Designed system modifications to increase system reliability from power plant. Prepared load flow, short circuit, system planning for the 115-kV interconnections.

Fort Peck, Montana 1975

Analyzed voltage problems associated with loss of generating unit and Ferranti effects on 230-kV system.

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

RECEIVED

JUL 1 9 2000

PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE)
PLAN OF BIG RIVERS)
ELECTRIC CORPORATION) Case No. 99-429

SUPPLEMENTAL REQUESTS FOR INFORMATION OF THE ATTORNEY GENERAL

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits these Supplemental Requests for Information to Big Rivers Electric Corporation, to be answered by the date specified in the Commission's Order of Procedure, and in accord with the following:

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

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

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

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

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

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

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

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

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

Respectfully submitted,
A. B. CHANDLER, III
ATTORNEY GENERAL

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, KY 40601
(502) 696-5358

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that this the 18th day of July, 2000, I have filed the original and ten true copies of the following supplemental requests for information of the Attorney General with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Ky., 40601, and certify that this same day I have served the parties by mailing a true copy of same, postage prepaid, to the following:

JOHN STAPLETON
633 TETON TRAIL
FRANKFORT KY 40601

HON IRIS SKIDMORE
HON RONALD P MILLS
OFFICE OF LEGAL SERVICES
FIFTH FLOOR
CAPITAL PLAZA TOWER
FRANKFORT KY 40061

DAVID SPAINHOWARD
VICE PRESIDENT BIG RIVERS ELECTRIC CORPORATION
P O BOX 24
HENDERSON KY 42420

HON JAMES M MILLER
SULLIVAN MOUNTJOY STAINBACK & MILLER PSC
100 ST ANN STREET
P O BOX 727
OWENSBORO KY 42302

HON DOUGLAS BERESFORD
HOGAN & HARTSON LLP
555 THIRTEENTH STREET N W
WASHINGTON D C 20004-1109

[signature]

SUPPLEMENTAL REQUESTS FOR INFORMATION OF THE ATTORNEY GENERAL

1. Follow-up to Item 1. The IRP mentioned that the Willamette generator would be available in 2001. Please provide the current status of the project, and whether the project is on-schedule to be completed by the date mentioned in the 1999 IRP.

2. Follow-up to Item 2c. This response contained "Gross Revenue ($/MWH)" figures for 2000 and beyond that were substantially higher than the gross revenues in response 2b of $42.2/MWH in 1998 and $37.2/MWH in 1999. Please explain in detail the basis for the projections in 2c, and why they are so much higher than the actual revenues received in recent years?

3. Follow-up to Item 2. This response shows actual and projected revenues from arbitrage sales prior to 2011, that were not contained in the Workout Plan. With respect to these unplanned revenues:
   a) Will these revenues be used to help repay Big Rivers' debt? If so, please provide any projections of how this revenue stream will move forward the date by which Big River's is expected to have repaid it debts.
   b) The Workout Plan contained a projected rate increase to member coops within the first 10 years. Will these revenues be used to minimize or eliminate the need for this rate increase? If so, please provide an updated projection on the timing and amount of any proposed rate increase.

4. Follow-up to Item 3. This response shows actual and projected sales to members in the IRP substantially above those contained in the Workout Plan. These additional sales should provide Big Rivers with revenues beyond those projected in the Workout Plan. With respect to these unplanned revenues:
   a) Will these revenues be used to help repay Big Rivers' debt? If so, please provide any projections of how this revenue stream will move forward the date by which Big Rivers is expected to have repaid it debts.
   b) The Workout Plan contained a projected rate increase to member coops within the first 10 years. Will these revenues be used to minimize or eliminate the need for this rate increase? If so, please provide an updated projection on the timing and amount of any proposed rate increase.

5. Follow-up to Item 5. What has Big Rivers or the three coops done to inform coop members that Big Rivers will look favorably toward distributive generation and will work with members considering such generation?

6. Follow-up to Item 6. What is Big Rivers' definition of "feasible and viable"? Are distributive generation projects evaluated against Big Rivers' avoided costs of under 20 mils, or the three coops' avoided costs of 30.47 mils for large industrial or 36.44 mils for residential customers?

7. Follow-up to Item 7. Why would run-of-river hydro with a capacity factor of 60% be considered too high of a load factor to be considered at this time, while biomass with capacity factors in the 80% to 90% range is not considered too high a load factor to consider now?

8. Follow-up to Item 8. Please provide a comparison of biomass fuel costs for plantation grown trees versus locally available wood-waste such as sawdust from area sawmills.

9. Follow-up to Item 9. The R.W. Beck study was done in 1995, before the restructuring of Big Rivers, and thus contains system related costs that are no longer appropriate. Has Big Rivers made any attempt to update the R.W. Beck study with updated post-restructuring costs?

10. Follow-up to PSC Item 5, page 7 of 9. This response states that strategic conservation will have a negative financial impact on Big River and cause member rates to rise.
    a) Please provide a detailed explanation of how lost sales to distributive generation, which Big Rivers is encouraging, is any different from lost sales due to strategic conservation.
    b) Big Rivers' response to the Attorney General's Request, Item 2, shows present and projected revenues from sales of surplus energy at a price above the 33.78 mils Big Rivers receives from member coops. Please explain why strategic conservation is not a win-win concept, since members can reduce their bills and Big Rivers can receive more revenues than it would selling this surplus energy to members (and reducing the need for new capacity also).

11. Follow-up to DOE Item 7. This response states that renewables are not commercially viable today.
    a) Please provide all studies that back-up this claim.
    b) Please provide the retail rate levels being paid to each of the three coops by both residential and industrial members, against which the viability of renewable resources would be measured.

12. Follow-up to DOE Item 19b. This response states that these DSM options scored poorly on the RIM test. In generating these poor RIM results, did Big Rivers factor in the fact that any energy saved could be sold off-system at a large margin such as those included in Big Rivers' response to the Attorney General's request, Item 2c, where selling this energy off-system can actually be a net benefit to ratepayers?

1.

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602-0615
www.psc.state.ky.us
(502) 564-3940
Fax (502) 564-3460

B. J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

July 18, 2000

James M. Miller, Esq.
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Building
Post Office Box 727
Owensboro, Kentucky 42302-0727

RE: Case No. 99-429, Big Rivers Electric Corporation

Dear Mr. Miller:

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

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

Enclosure

EDUCATION PAYS

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602-0615
www.psc.state.ky.us
(502) 564-3940
Fax (502) 564-3460

B. J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

CERTIFICATE OF SERVICE

RE: Case No. 99-429
Big Rivers Electric Corporation

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed copy of the Commission Staff's data request in the above case was served upon the following by U.S. Mail on July 18, 2000.

Parties:

Mr. David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P.O. Box 24
Henderson, KY 42419-0024

Mr. James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, KY 42302-0727

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

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

Ms. Iris Skidmore
Mr. Ronald P. Mills
Counsel for Natural Resources
And Environmental Protection
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Mr. Douglas Beresford
Counsel for Big Rivers Electric
Long, Aldridge & Norman
Suite 600
701 Pennsylvania Avenue
Washington, D.C. 20004

Stephanie J. Bell
Secretary of the Commission

Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	)))	CASE NO. 99-429

COMMISSION STAFF'S SECOND REQUEST FOR INFORMATION TO BIG RIVERS ELECTRIC CORPORATION

The Commission Staff requests that Big Rivers Electric Corporation ("Big Rivers") file an original and 6 copies of the following information, with a copy to all parties of record, by no later than August 18, 2000. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 5. Include with each response the name of the person responsible for responding to questions relating to the information provided.

1. Refer to Item 1 of the response to the Commission Staff's May 19, 2000 Request for Information. Provide a summary of any activity that has occurred under the "Curtailable Service" program offered by Big Rivers since the filing of that response.

2. Refer to Item 5, page 9 of 9, of the response to the Commission Staff's May 19, 2000 Request for Information. As stated, Big Rivers no longer

has direct responsibility for environmental compliance at its generating units under the terms of the Big Rivers/LG&E Energy transaction. However, Big Rivers is responsible for a share of the cost incurred for environmental compliance for its generating units. Provide a general narrative description of any modifications being considered for the Big Rivers generating units in order to comply with EPA's NOx SIP Call and an estimate of the cost and rate impacts such modifications will have on Big Rivers.

3. Refer to Item 11, part (b) of the response to the Commission Staff's May 19, 2000 Information Request. The response indicates that "Big Rivers will benefit from waiting as long as possible to secure the additional needed resources." The response also indicates that "Big Rivers intends to maintain as much flexibility as possible in planning for its supply of capacity to its members." Provide a side-by-side comparison of the scenarios Big Rivers has analyzed showing when Big Rivers would have to take action to begin the process of adding new generating capacity to its system.

4. Refer to Item 16 of the response to the Commission Staff's May 19, 2000 Information Request which indicates that the three-year plan referenced in Part VII of the IRP is based on the filing schedule set out in 807 KAR 5:058, Section 2(a)5. Under that schedule, Big Rivers was scheduled to file its IRP by April 21, 1998. However, Big Rivers has been granted deviations from the filing schedule contained in the regulation and was allowed to file its IRP by no later than October 21, 1999. Under the schedule contained in the regulation, Big Rivers' next IRP is scheduled to be filed by April 21, 2001. Indicate whether Big

Rivers expects to file its next IRP at that time or whether it intends to ask for some deviation from the filing schedule set out in the regulation.

5. Refer to Item 21 of the response to the May 18, 2000 Information Request of the Kentucky Division of Energy. Provide a narrative description of the interconnection with LG&E in the 2002-2003 timeframe that Big Rivers is currently studying. Also, differentiate between the possible 2002-2003 interconnection with LG&E referenced in Item 21 and the existing interconnection with LG&E that is referenced in Big Rivers' IRP in Section II, page 7.

6. Has Big Rivers considered participation in the Midwest ISO?

7. According to Big Rivers' response to Item 11, page 2 of 2 of the Commission Staff's first data request, Big Rivers will be considering and evaluating other tariff and rate options which would further reduce capacity demand. Discuss the potential tariff and rate options being considered, their estimated potential to reduce demand, and the approximate timeframe envisioned for filing and/or implementing them.

8. Relative to Big Rivers' response to Item 4 of the Commission Staff's first data request, Big Rivers indicated that it has eliminated its participation in residential DSM programs involving direct cash incentives, and that it would continue to provide information on energy efficiency for residential customers. Relative to the IRP's "best-of-all-worlds" scenario of "repackaging programs as 'Customer Satisfaction' options offered to the customers," explain in detail the following:

a) What types of programs are potential targets for repackaging?

b) What specific plans, if any, does Big Rivers have in this regard?

c) What is the specific involvement envisioned for Big Rivers, versus that of its member cooperatives, in such a repackaging effort?

d) Would such a repackaging have any potential for positively influencing Big Rivers future resource requirements, or would it be used only for marketing purposes (i.e. to increase customer satisfaction)?

9. Relative to the possibility of 62 MW of generation by Willamette Industries, Inc., Big Rivers' IRP indicated that the contractual arrangements were in the process of being drafted and that the unit was expected to be operational in the spring of 2001, and a data request response indicated that Big Rivers' capacity situation could be better determined in early 2001. Provide a timeline to give the latest understanding of the crucial developments related to this situation, including the dates (i.e., month and year) when the contract is expected to be finalized, construction is expected to begin, and the unit is expected to be operational.

Respectfully submitted,

Richard G. Raff

Richard Raff
Staff Attorney

RECEIVED
JUL 13 2000
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF	)	
BIG RIVERS ELECTRIC COPRPORATION	)	**CASE NO. 99-429**

KENTUCKY DIVISION OF ENERGY'S SECOND REQUEST FOR INFORMATION TO THE BIG RIVERS ELECTRIC CORPORATION

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

1. Follow-up to KDOE Item 6b, 1st set:

a. The first paragraph of the witness' response includes the sentence, "The goal of strategic conservation is to reduce overall consumption, with a primary focus on energy." Figure IV-1 of the IRP, however, shows that strategic conservation also reduces the peak load. Isn't it true that reducing the peak load can lead to a reduction in a utility's revenue requirements?

b. Isn't it true that a DSM program that reduces demand by a constant amount all year round can have a Utility Cost ratio greater than 1.0?

c. Isn't it true that the Utility Cost test is also known as the Utility Revenue Requirements test, since it measures the change in revenue requirements?[1]

d. Doesn't it follow from the foregoing that a well-designed and properly-implemented strategic conservation program could reduce the utility's revenue requirements (as well as reducing total resource costs)?

e. Would Big Rivers agree that a reduction in revenue requirements would benefit the utility (as well as the customers)? If not, please explain.

f. The last paragraph of the witness' response to this item includes the sentence, "The only type of measure, within the general category of DSM that will benefit both the utility and the customers, is one which will simultaneously shave peak and (may) fill valleys..." In this sentence, isn't Mr. de Leon focusing only on rate impacts (i.e., on a DSM program's RIM test result)? If not, please explain the response.

g. We continue not to understand how the economic impacts on Big Rivers of strategic conservation differ significantly from those of distributed generation. An industrial cogeneration unit, for example, might generate electricity at or near capacity virtually all year round. The Kenergy customer's planned 62-MW cogeneration unit is expected to be available 97% of the time, i.e., almost all year round.[2] Looking at Figure IV-1 of the IRP, it seems clear that a DSM program having this kind of impact would fall into the category of "strategic conservation." We therefore feel the need to reiterate: It seems to KDOE that strategic conservation would also lower peak demands and energy requirements and provide Big Rivers with greater flexibility in its power

[1] Gellings, Clark W. and John H. Chamberlin, *Demand-Side Management Planning*, 1993, Fairmont Press, p. 266.
[2] Response to Attorney General's (AG) Item 1d, 1st set.

supply operations. Why does the IRP recommend against strategic conservation, even though it appears to have beneficial characteristics and impacts similar to those of distributed generation?

2. Follow-up to KDOE Item 7a, 1st set: Does the response mean that Big Rivers believes that there are no applications of fuel cells or renewable electric technologies that are presently commercially viable, or that could provide economic benefits to both the utility company and its customers? Please explain.

3. Follow-up to KDOE Item 8, 1st set: To what degree, if any, did membership in E Source by the National Rural Electric Cooperatives Association give Big Rivers and Burns & McDonnell access to E Source's technical reports, issue briefs, and other technical services?

4. Follow-up to KDOE Item 18, 1st set:

a. Approximately how many energy use assessments, operation assessments, and coordinated energy and waste assessments are performed annually in the service areas of Big Rivers' member cooperatives?

b. Approximately how much money has been loaned to customers for weatherization and energy efficiency improvements?

c. Please provide a more detailed description of the "work with homebuilders on weatherization and energy efficient construction techniques."

d. If available, please provide the estimated energy and demand impacts of the programs described in the response to KDOE Item 18, 1st set.

5. Follow-up to KDOE Item 19, 1st set:

a. Do the terms "stranded" and "fleeting" investments refer to a restructured utility industry that may be instituted in Kentucky at some time in the future?

b. What is Big Rivers' best estimate as to when (or whether) electric industry restructuring may occur in Kentucky?

c. Is Big Rivers aware of KRS 278.285, which authorizes the Commission to consider and approve "a utility's proposal to recover in rates the full costs of demand-side management programs, any net revenues lost due to reduced sales resulting from demand-side management programs, and incentives designed to provide positive financial rewards to a utility to encourage the implementation of cost-effective demand-side management programs"? Please discuss the concepts of "stranded" and "fleeting" investments in the context of this statute.

d. Referring to the first paragraph of the response, is the witness aware that changes in revenue requirements are measured most directly by the Utility Cost (UC) test?

e. Part (a) of the response to this item contains the phrase, "it is likewise the members responsibility to serve all ratepayers (RIM test)..." Part (b) of the response contains a similar phrase: "all-ratepayers test (RIM)". The last paragraph on page IV-3 of the IRP, however, contains the following sentences: "The Total Resource Cost (TRC) test is a measure of a program's benefits versus costs for all ratepayers, and is sometimes called the 'all ratepayer' test. The Rate Impact Test (RIM) is a measure of rate impacts for a utility." KDOE concurs with the sentences in the IRP and believes that the phrases that associate the all-ratepayer test with the RIM test are incorrect.[3] Please explain this discrepancy.

f. Would it be accurate to say that the primary criterion used by Big Rivers for the past six years or more when deciding which DSM programs to implement has been the effect on rates (RIM test)? If not, please explain.

g. The section on "Necessity, Function, and Conformity" of the IRP regulation, 807 KAR 5:058, refers to utility plans "to meet future demand with an adequate and reliable supply of electricity at the *lowest possible cost for all customers* within their service areas..." (emphasis added). In view of this regulation and Question (e) above, would Big Rivers agree that the primary criterion showing whether all ratepayers are being optimally served should be the TRC, or All Ratepayers test? If not, please explain.

6. Follow-up to KDOE Item 21, 1st set:

a. Approximately how much of the $21 million projected for transmission improvements by the Long Range Engineering Plan for 1995-2015 remains to be invested during the period 2000-2015?

b. Approximately how much additional investment will be required for distribution (not transmission) system upgrades during the period 2000-2015?

c. Approximately how much investment (transmission and distribution) will be required for the "improvements projected and contingent upon load growth predicted in Big Rivers' Power Requirements Study" during the period 2000-2015?

[3] Gellings and Chamberlin, pp. 260, 263.

7. Follow-up to KDOE Item 22, 1st set: The response indicates little if any interest by Big Rivers in investigating the potential benefits of local integrated resource planning (LIRP). In view of the highly positive financial results obtained by other utility companies through their use of LIRP, please explain why Big Rivers and its member cooperatives would not be keenly interested in exploring potential new ways to reduce projected utility costs related to their transmission and distribution systems.

Respectfully submitted,

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

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing KENTUCKY DIVISION OF ENERGY'S SECOND REQUEST FOR INFORMATION TO THE BIG RIVERS ELECTRIC CORPORATION was mailed, first class, postage prepaid, the 13th day of July, 2000, to the following:

David A. Spainhoward
Vice President
Big Rivers Electric Corporation
P. O. Box 24
Henderson, KY 42419-0024

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

Hon. James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
P.O. Box 727
Owensboro, KY 42302-0727

Hon. Douglas Beresford
HOGAN & HARTSON L.L.P.
555 Thirteenth Street, N.W.
Washington, DC. 20004-1109

Iris Skidmore

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

June 28, 2000

Martin J. Huelsmann, Jr.
Executive Director
Public Service Commission of KY
211 Sower Blvd., P.O. Box 615
Frankfort, KY 40602-0615

Re: The Integrated Resource Plan of Big Rivers Electric Corporation, PSC Case No. 99-429

Dear Mr. Huelsmann:

Enclosed are the affidavits of publication and tear sheets concerning the notice published by Big Rivers Electric Corporation ("Big Rivers") in the above-referenced matter. Big Rivers acknowledges that the notice was not published "within thirty days of the filing of this Integrated Resource Plan" ("IRP") as required by the order of the Public Service Commission ("Commission").

Big Rivers was unable to publish the notice in accordance with the Commission's direction. The regulation of the Commission requiring publication of notice, 807 KAR 5:058, §10, requires Big Rivers to publish notice "in a form prescribed by the commission." Big Rivers' IRP was filed March 21, 2000. The Commission's order prescribing the form of notice for Big Rivers to publish was not issued until April 28, 2000, more than thirty days later. The notice prescribed by the Commission was published within thirty days from the date of the Commission's order.

A copy of this letter, without attachments, is being served today by mail on each of the parties on the attached service list, postage prepaid.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej
Enclosures

cc: Doug Beresford
David Spainhoward
Service List

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

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

SERVICE LIST
CASE NO. 99-429

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

Office of the Attorney General of the Commonwealth of Kentucky

John Stapleton
Director of Energy
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Hon. Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Counsel for Natural Resources and Enviromental Protection

AFFIDAVIT OF PUBLICATION

Laurie White of Owensboro, Kentucky being first duly sworn, says that she is Credit Coordinator of the Owensboro Messenger-Inquirer, Inc. a newspaper printed and published in the State of Kentucky, County of Daviess, and that the advertisement is a true copy which has been published in the Messenger Inquirer on the following dates, viz: May 19th, 2000.

Laurie White

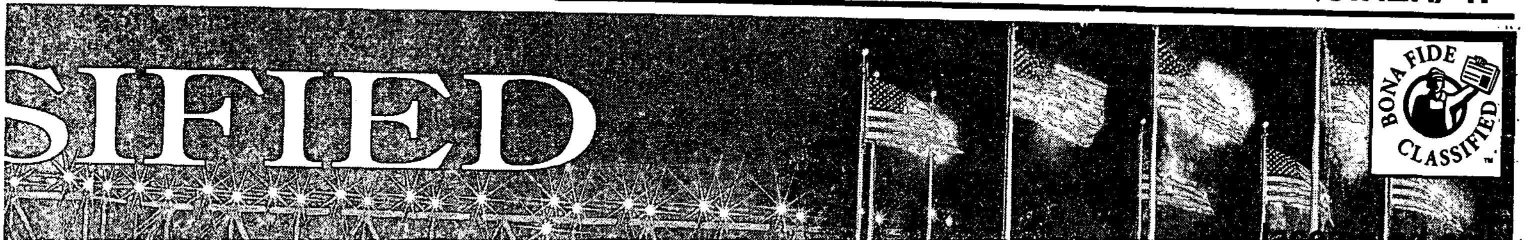
Laurie White

Subscribed and sworn to before me, a Notary Public within and for the State and County aforesaid, by Laurie White to me personally known, this 19th day of May, 2000. My commission expires the 28th day of February, 2001.

Ella Mae Peay

Ella Mae Peay

County of Daviess
Notary Public State of Kentucky



ırd toys, little girls 3 mo. to) mo. 25" color t.v., Misses othing, lots of household & isc. 7-3

KIPLING DR.-4007- Rain or Shine. ★ We Have Tons of tuff! ★ toys, books, clothes, furniture, Knick Knacks.

AKESHORE POINTE, 2549- othes, t.v., bikes, picnic ta- e. **Fri. and Sat. 7:30-12.**

ANDSDOWNE S., 2205 - aturday only 5/20, 7-? furni- re, suits, shoes, clothes, oset doors & misc.

MAPLE AVE., 803. Clothes: 0-12 yrs. child, 18-22 women's, baby stuff, major kitchen appl. Toys, misc. ***Thurs. & Fri. 7-?***

MAYO AVE., 1621 - Fri 1-5 & Sat. 8-? in garage in back. Lots of Misc. Rain or Shine!

McCreary Ave.-1818- *Remodeling Sale!* Queen Anne sofa, Wing back chairs, mower, car seat, changing table, maternity-kids-adult- clothes, patio furniture, brass inges, TV/VCR, doors, fabric.

women's clothes (size 10-12.) Shoes, purses, misc. **SAT. 8-1.** *No Early Sales!*

PLAUDIT PL. 3509 Thoro- bred East Gigantic Sale! Toys, baby accessories, over 500 pieces of baby clothes 0 - size 7 plus adult sizes, lots of misc. **FRI. & SAT. 7-?**

PLEASANT GROVE RD. 4651 *Multi-Family Sale!* Childrens clothes (all sizes) & other misc. **Sat. 6 -12**

REID RD., 418 Lot 47 - Yard Sale! New wedding dress, size 20, $100 OBO, men' women plus size, and toddler girls clothes, toys and misc. No sales before 7 am

RIDGEWOOD ST., 2910. *Mega Multi-Family Sale Friday* Household, kid's/women/men clothes, toys, duck collection. *Christmas decorations,* CDs, albums, books, software, concrete benches, electron- ics, mower, quilt scraps, etc.

Ridgewood St.-2926- Sat. only! 8-12. Too Much Stuff!!! *Cleaning house-***Everything Must Go!** ✦ MUST SEE!!!! ✦

(off Parrish Ave.) Clothing, shoes, dishes, desk, electric range, plants & Memorial Day Saddles/Crosses. **8 - ?**

WEST 20TH ST., 117. SAT. Wedding dress, chandeliers, mirrors, wall lights, car seat, high chair & lots of misc.

WEST 5TH ST., 1820. *4 Families!* Nice name brand clothing: children thru adult; Tommy, Polo, Nautica & *MORE!* **FRI. ONLY 6-?**

WHIRLAWAY DR., 2417. Fri. & Sat. 6-? Furniture, washer & dryer, men & women's clothes, misc.

WILL PICK UP ALL left over sales (garage, estate sales, etc.) ***We are helping the less fortunate at St. Vincent DePaul*** 683-1747. *Two locations to drop off between 8 am & 4 pm.* ***1001 W. 7th St. or 18th & Triplett St.***

WINDSOR AVE. 2504- Sat. 7-12 Rain Cancels. ***Two fam- ily!*** Lots of everything.

x 4 tires & bed rails for short bed. Canning jars, etc. *CASH ONLY!* **Fri. & Sat. 7 am**

HWY. 140 W., 165 - 3 fami- lies! **8-?** Everything from A to Z, clothing- kids & adults.

870 Pleasant Ridge

Highway 764 -4737- lots of glassware, movies, pie safe, toys, dolls, infant-children- adult clothing, jewelry, Misc. ***Sat. May 20th 8AM-?*** **☆ Watch for Signs! ☆**

872 Maceo

PLEASURE POINT RD., 9219 SAT. 7-NOON! Lg. replace- ment window, new stainless steel sink, adult clothes, tomato & hot pepper plants.

875 Masonville

SUTHERLIN LN., 6215. Women's clothes size 2 & 3, petite size 12, men's X-Lg. '78 Jeep, misc. ***Fri. & Sat. 7-?***

Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frank- fort, Kentucky 40602.

PUBLIC NOTICE

C&T Entertainment, Inc., 105 W. 2nd St., Owensboro, KY 42303, hereby declares in- tentions to apply for a Retail Liquor Drink, Supplemental Bar, Malt Beverage Retail Beer licenses no later than June 30, 2000. The business to be licensed will be located at 105 W. Second Street, Owensboro, KY 42303. Doing business as Wild Hare Saloon. The principal officers are as follows:
President, Cindy Kirk of 453 Blackburn Ave., Ashland, KY 41101
Vice President, Theresa Adkins of 5605 Lit- tleridge Dr., Louisville, KY 40229
Vice President, Bill Adkins of 5605 Littleridge Dr., Louisville, KY 40229
Any person, association, corporation, or body politic may protest the granting of the license by writing the Department of Alcohol- ic Beverage Control, 1003 Twilight Tr., A-2, Frankfort, Ky. 40601, within 30 days of the date of this legal publication.

5-19

AFFIDAVIT OF PUBLICATION OF NOTICE

Affiant, being first duly sworn, states as follows:

1. Affiant is employed by The Gleaner, publisher of the newspaper The Gleaner, as its Classified Sales Rep.

2. The Gleaner is a newspaper of general circulation within the City of Henderson, County of Henderson, Commonwealth of Kentucky, and surrounding areas. It is published daily.

3. A notice, a true copy of which is attached hereto, was published in said newspaper on the 17th day of May, 2000.

Becky Yates

Subscribed, sworn to and acknowledged before me by Becky Yates on this 17 day of May, 2000.

Karen B. Bryant

Notary Public, Ky. State at Large
My commission expires: May 26, 2000

Recieved Time May.15. 3:30PM

IN REVIEW

[etals

[NEW YORK (AP) — Spot nonferrous metal [pric]es Tuesday.
[A]luminum - 68.0 cents per lb., London Metal [Exc]h. Tue.
[C]opper - $88.0 Cathode full plate, U.S. desti[nat]ions.
[C]opper - 84.60 cents per lb., N.Y. Merc spot
[L]ead - 29-31 cents per lb.
[Z]inc - 58.16-58.66 cents lb., delivered.
[G]old - $276.00 troy oz., Handy & Harman [(onl]y daily quote).
[G]old - $275.50 troy oz., NY Merc spot Tue.
[S]ilver - $5.145 Handy & Harman (only daily [quo]te).
[S]ilver - $5.108 troy oz., N.Y. Merc spot Tue.
[M]ercury - $150.00 per 76 lb flask, N.Y.
[P]latinum - $510.00-$520.00 troy oz., N.Y. [(con]tract).
[P]latinum - $483.50 troy oz., N.Y. Merc spot

[Pe]troleum

[N]EW YORK (AP) — Petroleum cash prices [To]day compared with Monday prices:

	Tue.	Mon.
[Ref]ined Products		
[Fu]el oil No. 2 NY hbr bg gl fob	.7897	.7983
[Ga]soline unl prem RVP NY hbr bg gl fob	1.0306	[1.0]54
[Ga]soline unl RVP NY hbr bg gl fob	.9244	.9067
[Pri]ces provided by Bridge Telerate		
[Pet]roleum - Crude Grades		
[Sau]di Arabian light Asia $ per bbl fob	28.33	[2]8
[No]rth Sea Brent $ per bbl fob	28.44	28.44
[We]st Texas Intermed $ per bbl fob	29.73	29.93
[Ala]ska No. Slope del. West Coast	28.03	28.22
[Dr]y Products		
[N]. Gas, Henry Hub, $ per mmbtu	3.46	3.37

[Co]mmodities

[Asso]ciated Press
[F]orecasts for substantial rains this week in [the W]est growing regions, soaking fields in the [star]t of planting season, sent soybean and corn [price]s tumbling Tuesday on the Chicago Board of [Trade].

[...]f rally'

[...]ssions following previous rate

[...]has been improving since last [...]ery little fundamental good [...]"Volume has been low and the [...]e advance has not been that [...] raises questions about the [p]ower."

[...]om the start of trading after [...]rtment offered some evidence [pr]evious rate increases may be [ho]lding inflation down. The gov[...]mer price index, after rising [...] straight months, held steady [ene]rgy prices posted their first [...]t a year.

[...]–, an area Dodge office, Construction Market Data office, or Tri-State Construction News office.

NOTICE OF COMPETITIVE SEALED BIDDING

The Henderson County Board of Education will receive written sealed bids in the office of the Board of Education, 1805 Second Street, Henderson, Kentucky, until 9:30 A.M. (prevailing time), Wednesday, May 31, 2000 at which time the bids will be opened. Bids will be received for Bakery Products, Diary Products, Fresh Doughnuts, and Snack Items.

The award shall be made on the basis of the lowest bid price or the lowest evaluated bids price.

The Board of Education reserves the right to accept or reject any or all bids in whole or in part if in its judgement the best interest of the schools will be served.

CONFLICTS OF INTEREST, GRATUITIES AND KICKBACKS AS DEFINED IN KRS 45A.445 AND AS PROVIDED FOR IN KRS 45A.455 ARE ABSOLUTELY PROHIBITED. THE PROVISIONS OF THESE STATUTES SHALL BE NOTED AND ACKNOWLEDGED BY THE USERS OF THIS PROCUREMENT DOCUMENT

All bids shall be submitted on forms furnished by the Board of Education. Bids submitted on other forms may be rejected a non-responsive.

Walt Spencer
Finance Director/
Board Treasurer

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky [...] to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

100 ANNOUNCEMENTS

NOTICE TO READERS
Investigate fully before sending any money as an advance fee. For further information and assistance regarding the investigation of financing, business opportunities, and work at home opportunities, The Gleaner urges its readers to contact the Tri-State Better business Bureau, 4004 Morgan Avenue, Suite 201, Evansville IN 47715-2265 or phone 1-800-359-0979.

200 HAPPY ADS

Happy 22nd Birthday, Brad P.

Love – Mom, Brynn, Amanda & "Maddie"

900 LOST & FOUND

Found, East Heights School area, small male Yorkie. Call 830-8353.

Found! Pit Bull, vicinity of Meadow and Pringle, 826-1716 to claim.

Lost in Anthoston area, white Himalayan cat, shaved like Lion, family pet, please call 827-9087.

Lost tan shoulder purse Saturday with keys & billfold. If found, there is a reward. Phone 826-2956.

Missing from Pleasantview area, "Freckles", a white and light rust color rabbit with freckles. Child is heartbroken. Please call after 6 p.m., 826-2891.

1100 PERSONALS

My Weather
It's like having your own private meteorologist. Anytime. Anyplace. Best of all, it's *FREE*.
Visit My Weather at
www.TheGleaner.com

1200 PERSONAL SERVICE

UNCONTESTED DIVORCE
L.B. Lawton, Attorney
$250 plus costs.
Call 827-5353

1300 SPECIAL NOTICE

2000 EMPLOYMENT

FULL-TIME GRILL COOK/ BREAKFAST COOK
Apply in person:
GENE'S RESTAURANT
1095 N.Green St.
Between 8 a.m. & 1 p.m.

ATTENTION!
Interested in a sales career? CENTURY 21 Collier & Company is seeking hard working individuals for a full time career in real estate. Call Jim Collier 270-827-5624.

AFFIDAVIT OF PUBLICATION OF NOTICE

Affiant, being first duly sworn, states as follows:

1. Affiant is employed by Jim Hurst, publisher of the newspaper Tribune Courier, as its General Manager

2. Tribune Courier is a newspaper of general circulation within the City of Benton, County of Marshall, Commonwealth of Kentucky, and surrounding areas. It is published weekly.

3. A notice, a true copy of which is attached hereto, was published in said newspaper on the 24 day of May, 2000.

Subscribed, sworn to and acknowledged before me by Jim Hurst on this 24 day of May, 2000.

Valma Gore
Notary Public, Ky. State at Large
My commission expires: 11-17-02

THE TRIBUNE-COURIER

CLASSIFIEDS

WEDNESDAY, MAY 24, 2000

CLASSIFIED INDEX

3 NOTICE

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

NOTICE

There will be an election on Saturday, June 24, 2000, between the hours of 11 a.m. and 2 p.m. at the #1 Fire Station, located at 7491 Moors Camp Hwy., Gilbertsville, KY 42044. This term is for 4 years on the East Marshall Fire District. Running for this office is incumbent, Harold Dempsey, 285 Cambridge Shores Drive, Gilbertsville, KY 42044.

"AN ORDINANCE ANNEXING PROPERTY OWNED BY DOUG DOTSON, RITA DOTSON, JERRY ENGLISH, BONNIE ENGLISH, JOHNNY CARTER, KENNA CARTER, TERRY HOLT, CAROLYN HOLT, JAMES KIP PHILLIPS, CAROLYN PHILLIPS, DON FRIZZELL, PAT FRIZZELL, ROY RILEY, JENNIFER RILEY, DOUG GALYEN, JANE GALYEN, JERRY AUSTIN AND PAULA AUSTIN." This Ordinance is summarized as follows: The Property Owners of Bent Creek, Unit 2, ask that said property be annexed into and made a part and portion of the City of Benton, KY. A complete copy of this Ordinance is available for viewing at the City hall during regular business hours.

I hereby certify that the above is a true and correct summary of an Ordinance adopted by the City of Benton on May 15, 2000.

MARTIN W. JOHNSON
City Attorney
Post Office Box 450
Benton, KY 42025

NOTICE

There is an election being held on Saturday, June 24th between the hours of 11 a.m. and 2 p.m. at the Fairdealing/Olive Volunteer Fire Protection District fire house for one opening on the Board of Trustees. The candidates for the election are Jerold T. Jones, and Tom Haynes (incumbent). All citizens of the district are encouraged to come and cast a vote.

The newly elected Board member will begin their term July 1.

2) 12' wide by 52' long (on lot #8)
3) 12' wide by 48' long (on lot #9)
4) 12' wide by 48' long (on lot #11)
5) 23' wide by 53' long (on lot #2)

Location of sale: Stevenson Trailer Park
Hwy. 62 just west of H
Trailers may be seen at any time at trai

Terms of sale: Cash

NO WARRANTIES APPLY.

TERI
SHERIFF OF MARSI

NOTICE OF ELECTIO

This notice is to hereby inform y KRS 424 et sec. of the Need to Hold a Board of Director of the Gilbertsville District. This election shall be held or June, 2000, between the hours of 5:00 I at the Gilbertsville Fire House locat Dam Village, Gilbertsville. Person placing their names in nomination sl Gilbertsville Fire Protection District 362-8862 no later than the 31st day of M

Those wishing to place their name for election must be a resident of the C Protection District.

For information on this election James G. Dexter at 362-4294.

[redacted]

AFFIDAVIT OF PUBLICATION OF NOTICE

Affiant, being first duly sworn, states as follows:

1. Affiant is employed by The Messenger, publisher of the newspaper Messenger, as its Classified Rep.

2. The Messenger is a newspaper of general circulation within the City of Madisonville County of Hopkins, Commonwealth of Kentucky, and surrounding areas. It is published daily.

3. A notice, a true copy of which is attached hereto, was published in said newspaper on the 18th day of May, 2000.

Melanie Reynolds

Subscribed, sworn to and acknowledged before me by Melanie Reynolds on this 18th day of May, 2000.

Julie Dillon
Notary Public, Ky. State at Large
My commission expires: 5-21-04

275 legal notices

NOTICE

On March 21, 2000, Big Rivers Electric Corporation Filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Heulsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

NOTICE OF INTENTION TO MINE

Pursuant to Application Number 854-9002

275 legal notices

purpose of obtaining written or oral comments regarding the proposed use of Municipal Aid and Local Government Economic Assistance Program funds for the upcoming year.

Balance Carried Forward
$60,048 $9,200

Anticipated Receipts
$19,000 $3,000

Anticipated Interest Income
$3,000 $80

Total Resources Available for Appropriation
$101,048 $12,280

PUBLIC INSPECTION: The City's proposed budget and proposed uses of Municipal Aid and Local Government Economic Assistance Program funds are available for public inspection at City Hall during normal business hours.

Any person(s) (especially senior citizens) who cannot submit written comments or attend the public meeting, but wish to submit comments should call City Hall at (270)676-3384, so that the city can make arrangements to secure their comments.

PUBLIC NOTICE

Please take notice that the Hopkins County Fiscal Court

301 antiques

sectional couch, computer desk with chair, dining room suite, crafts, clothes, what knots & more.

5 FAMILY Yard Sale, 215 Sandcut Rd. Clothes, household items, baby items, lots of misc. Friday & Saturday, 7am-?

BIG MOVING Sale 260 Sandcut Rd. 7:30a.m.-? Thurs., Fri. & Sat. Adult clothes, infant clothes, kitchenware, furniture, much more.

FRIDAY & Saturday Yard Sale, household items & clothing & books. 114 Ayr Parkway (Grampian Hills)

FRIDAY 7AM-5PM, 1624 Sunrise Dr. Medium-plus sizes, baby items, movies, grill, CD's, lots more.

GARAGE SALE Fri. 7a.m.-? 515 Sandcut, Grapevine. Boys husky 12-14, little girls 3-5T, lots of misc. Rain date May 26.

INSIDE GARAGE SALE Fri. only. 8a.m.-2:30p.m. 2582 Club Court (off Country Club Ln. Electric lawn edger, John Deere dethatcher, aluminum fold-up garden cart, small T.V., ladies clothes size 12; mens sport coats, excellent condition size 44R, dishes & many other items. No early sales please.

MOVING SALE 217 N. Seminary Fri. 7a.m.-? Household items, furniture, curtains, adult & children clothing.

MOVING SALE Carmae's Antiques Thurs. & Fri. 8a.m.-4p.m. 1312 McLeod Ln. Shudders, tables, trunks, chairs, glassware, lots of misc.

MOVING SALE Fri. & Sat. 8a.m.-3p.m. 2849 Country Club Dr.

307 garage sales

mention. Cash only not responsible for accidents. Cancel if rain.

Manitou

GARAGE SALE Thurs. & Fri. 250 Wolf Hollow Rd., Manitou. Lots of baby & household items. Early birds welcome.

309 home furnishings

ETHAN ALLEN three cushion couch, $50, call 825-1786.

GREEN AND white couch & chair, $75, call 821-6928.

KITCHEN TABLE with four chairs, $75, call 821-5314 after 4pm.

QUEEN SIZE waterbed with accessories, $75, call 821-8358.

311 lawn & garden

AFFORDABLE RATES on tree/shrub trimming, AweGreen at 824-8384.

312 miscellaneous

45 AUTO ammo, box ball & box reloads, $15 all, call 258-9004.

BEAR COLLECTION: Ty Beanies, Attic Treasures & Buddies, shown by appt., call 322-8871.

BEDSIDE COMMODE, $20-$30, call 258-9004.

COUNTRY CURTAINS, tie backs, two pairs, like new, $50, 825-2963.

DYNO FLO kerosene heater, $60, call 825-0482.

EMBROIDERY BUSINESS, Melco commercial embroidery machine with computer, 7500 designs on CD, and supplies, call 249-3671.

FLOWER BOXES, $12.50, call 676-9342.

FOLDING WALKER, $25, footed cane, $15, call 258-9004.

312 miscellaneous

table, $50, call 821-5314 after 4pm.

314 wanted to buy

OLD GRANDFATHER clock, upright, does not have to work, call 825-3541.

411 apartments

CROSS CREEK Apts. accepting applications for one, two, three BR apts. Water furnished, laundry mat on site, rent and deposit based on income. Section 8. Apply M-F, 9am-12pm at 1505 Island Ford Rd or call 821-8826 or 1-800-648-6086 for hearing impaired.

CUTE, COZY one BR apt., new carpet linoleum, washer/dryer hookup, $230/month + dep., one year lease, call 825-4800.

DON'T PANIC! We have what you need! One or two BR apartments, all are fully carpeted with heat and air, stove and refrig. Give us a call and let us help you 821-2763.

FIRST MONTHS RENT FREE EASTSIDE APTS., one BR, water & sewer furnished. Rent starts $263/month. Call 821-8905 or TDD 1-800-545-1833, ext. 336 EOE.

FREE CABLE connection plus three months free cable service of your choice at the Brentwood Apts located within the view of woods. One BR fully carpeted with heat & air, stove & refrig., laundry on site. Call us at 821-2763.

NICE TWO BR apt., carpet, CHA, washer & dryer hookup, good location, $325/month, call 821-5812.

ONE BR upstairs apt., 222 Union Street, $195/month, $150/dep., ref. req., call 821-5765.

AFFIDAVIT OF PUBLICATION OF NOTICE

Affiant, being first duly sworn, states as follows:

1. Affiant is employed by Times Leader, publisher of the newspaper Times Leader, as its Editor.

2. Times Leader is a newspaper of general circulation within the City of Princeton, County of Caldwell, Commonwealth of Kentucky, and surrounding areas. It is published Wed & Sat.

3. A notice, a true copy of which is attached hereto, was published in said newspaper on the 20 day of May, 2000.

Clay Hutcheson

Subscribed, sworn to and acknowledged before me by Ellen Franklin on this 22 day of May, 2000.

Ellen Franklin

Notary Public, Ky. State at Large
My commission expires: Sept 15, 2003

May 28	Lowe
June 4	Dover Do
June 11	Michigan
June 18	Pocono R
June 25	Sears Poi
July 1	Daytona I
July 9	New Ham
July 23	Pocono R
Aug. 5	Indianapo
Aug. 13	Watkins G
Aug. 20	Michigan
Aug. 26	Bristol Mo
Sept. 3	Darlington
Sept. 9	Richmond
Sept. 17	New Hamp
Sept. 24	Dover Dow
Oct. 1	Martinsvill
Oct. 8	Lowe's Mo
Oct. 15	Talladega S
Oct. 22	North Caro
Nov. 5	Phoenix Inte
Nov. 12	Homestead

BUSCH GRAND

LOUDON, N.H. — Fedewa swept both and the victory in t 200 at New Hamps International Speec annual stand-alone was marred by the of fourth-generation Adam Petty, who cra practice at noon on the day before the e Green finished seco followed in order by Keller, Todd Bodine

Dale Earnhard

At Richmond, a Chevy prevented Excitement 400. second race of hi

NASCAR This W opinion: "Was the make it any easier 1999 rookie of the Yes."

FOR SALE — GENERAL

WANT A COMPUTER?

But no cash? MMX Technology will finance with "0" down. Past credit problems, no problem. Call toll free 1-888-718-4760.

$411 POOLS POOLS $411

Complete, 20x32 O.D. Family size pool including huge deck, filter system, fence cover, liner, skimmer, ladder, 100% financing. Call free 1-800-886-9557.

SAWMILL $3795

Saws logs into boards, planks, beams. Large capacity. Best sawmill values anywhere. Free information. Norwood Sawmills, 252 Sonwil Drive. Buffalo, NY 14225. 1-800-578-1363.

AUTOMOTIVE FOR SALE

1988 FORD T-BIRD

All power, V-6, complete, great body. Needs engine. Asking $2000. Call 270-365-4504.

AUTOMOTIVE FOR SALE

mates. Call 522-678 Caldwell, Owner, D Reddick, Operator. Barkley Continuous G ing.

LOFTON CONSTRUCTIO

Reasonable rates, 24 experience, fully ins No job too small. erences available. 27 7455.

INSULATION

Free estimates, expe ed & insured. Call Ton 965-2605, WRIGHT SULATION.

C&T LAWN SERVICES

No job too big or too Free estimates. cleaning also ava Chad Conger and Ti vis, owners and ope Call 270-388-9602.

FREE RING CLEANING

And Inspection; also appraisals. Hall's sale Jeweler, 106 Main, Princeton. 365

DEFINE YOUR S

Everyone enjoys tryi latest makeup shade with Mary Kay, it's eve fun. For free make o WENDY GILL, MAR Independent Beauty sultant, 270-545-70

ACCI

First Bank bids on a pickup VIN and a 199 Wheeler. Bi 18-00. Prop First Bank r fuse any or 365-4883.

REQUE

Adsmore Mu requests pro pair of the addition of meeting AD tions for wor

LEGAL NOTICES

LEGAL NOTICE 5-20-00

Marc Wells,
P.O. Box 644
Princeton, Ky. 42445

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

NOTICE

I will not be responsible for any debts other than those made by myself as of this date, 5-20-00.

Grayson County News - Gazette

P.O. Box 305 ♦ 208 South Main Street ♦ Leitchfield, KY 42755
A Media General Newspaper
Phone 502-259-9622 ♦ Fax 502-259-5537
Carol R. Bond ♦ General Manager

Carol R. Bond
General Manager

STATE OF KENTUCKY
COUNTY OF GRAYSON

I, Carol R. Bond, General Manager of the GRAYSON COUNTY NEWS-GAZETTE, newspaper of general circulation, published at Leitchfield, Kentucky, do solemnly swear that from my personal knowledge and references to the files of the said publication an advertisement for Sullivan, Mountjoy, Stainback, & Miller (Big Rivers Electric Corporation) was inserted on May 18, 2000.

Carol R Bond

Carol R. Bond
General Manager

Subscribed and sworn before me this 12th day of June.

Beverly Sue White
Notary Public

My commission expires: Feb. 1, 2001

Classi 9622

Classified Rates
Minimum Charges – 20 Words
10¢ Each Additional Word
hat classified be prepaid by 12 noon Tuesday for the edition and 12 noon Friday for the Monday edition

40 Misc. For Sale

DIRT FOR SALE. CALL 259-3014. (30908.tfn).

For Sale: Washer and Dryer. Refrigerator, stove and freezer. Excellent condition. Call 259-9748. (30269.th.tfn).

NEW PENTIUM CLASS COMPUTER! Low monthly payments. Poor credit OK! Toll-free 1-877-464-2847. (cnhi.15,18).

METAL BUILDINGS. Does your dealership not work for you? We have competitive prices & NO dealership fees! Call for a free brochure. El Dorado Building Systems 1-800-279-4300. (cnhi.15,18).

Sawmill $3,795. Saw logs into boards, planks, beams. Large capacity. Best sawmill value anywhere. FREE information. 1-800-578-1363. NORWOOD SAWMILLS, 252 Sonwill Drive, Buffalo, NY 14225. (cnhi.15,18).

WANT A COMPUTER??? BUT NO CASH?? MMX TECHNOLOGY. We Finance, "0" down! Past Credit Problems OK! Even if turned down before! Reestablish Your Credit!! 1-800-659-0359. (cnhi. 15,18).

40 Misc. For Sale

NEW BRAND NAME COMPUTERS - Almost everyone approved with $0 down! Low monthly payments! 800-617-3476, ext 330. (cnhi.15,18).

WANT A COMPUTER?? BUT NO CASH? MMX Technology will finance with "0" down. Past credit problems, no problem. Call toll free 1-877-293-4082. (cnhi.15,18).

NO MONEY DOWN! Compaq, HP, IBM, Desktops/Laptops, E-Commerce Websites. Start your homebusiness today! Almost everyone approved! Low monthly payments, free color printer (888)-479-2345, (toll-free). (cnhi.15,18).

41 Wanted

Tobacco Base - Want to buy tobacco bases, any amount of pounds. Call 270-879-9303 after 6:00 p.m. (30483. tfn).

41 Wanted

WANTED: Standing timber. Hardwood & Pine. References available. High Country Lumber. Ask for Vernon. 270-879-1200. (30388. tfn).

Wanted: Standing timber - Nolin River Logging. References available. 270-531-3751, let ring. (30579 tfn).

WANTED: Energetic individuals 21-39 who would like to help support local community project, enhance individual skills and make new friends. If you're interested in doing all of these things, please give Scott Mollyhorn a call at 502-259-9219. (nc tfn).

45 Pets

AKC Germand Shepard puppies for sale. Shots and wormed. Parents on premises. 270-879-4128. (pd.15,18).

BID NOTICE

The Grayson County Board of education will receive sealed bids until Thursday, June 1, 2000 at 9:00 a.m. CDT on Athletic and Physical Education Supplies. Applications for bidding and specifications may be picked up at the Superintendent's office, 909 Brandenburg Rd., Leitchfield, Kentucky. The Board reserves the right to accept or reject any part of any or all bids.

Dr. Craig Bangtson
Grayson County Board of Education

Dasc tere colo male tions 9862

4

Poll Grea size, ing STC Ceci 4462

For and gerti and & r back ser (30

For Hor aged finis after

will 1, 2 cal als and Supg Rd. serv of a

53 For Rent

For Rent 2 bedroom duplex. Deposit and references required. Call 259-6505. (30722. 11,15,18,22).

For Rent: 1 acre lot with trailer, look up. 316 N. Patterson in Clarkson. Clay Hodge. 242-7387. (30846. 5/18).

53 For Rent

For Rent - 2 bedroom apt. Ask for Sherrie. Call 259-2523. (30214. 11,18).

For Rent: Bridgewood apartments, 2 bdrm. Call Williams Chevron at 259-4645. (30824. thurs. tfn)

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Intergrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Franfort, Kentucky 40602.

THE COURIER JOURNAL and LOUISVILLE TIMES
Incorporated

TATE of KENTUCKY
ounty of Jefferson

Affidavit of Publication

I, Judy Reece
f THE COURIER-JOURNAL AND LOUISVILLE TIMES COMPANY, publisher
f The COURIER-JOURNAL, a newspaper of general circulation printed and published at Louisville, Kentucky, do solemnly swear that from my own personal knowledge, and reference to the files of said publication, the advertisement of

LEGAL 105 BIG RIVERS ELEC

was inserted in THE COURIER-JOURNAL as follows:

Date	Lines	Date	Lines
05/19/2000	34		

Judy Reece
(Signature of person making proof)

Subscribed and sworn to before me this 23 day of May, 2000.

My commission expires May 25, 2002.

Jerri Allison
Jerri Allison (Notary Public)

9262269 5I1L0160

Serving Breckinridge County Since 1876

THN The Herald-News

120 Old U.S. 60 • P.O. Box 6 • Hardinsburg, KY 40143
270-756-2109 • 270-547-2109 • FAX 270-756-1003
email thn@bbtel.com

AFFIDAVIT OF PUBLICATION OF NOTICE

Affiant, being first duly sworn, states as follows:

1. Affiant is employed by The Breckinridge Co. Herald News, publisher of the newspaper The Breckinridge Co. Herald News, as its Classified Advertising Manager

2. The Breckinridge Co. Herald News is a newspaper of general circulation within the City of Hardinsburg, County of Breckinridge, Commonwealth of Kentucky, and surrounding areas. It is published Weekly - Wednesdays

3. A notice, a true copy of which is attached before me by ____________ on this 25 day of May, 2000. Ad published May 24 issue.

Notary Public, Ky. State at Large
My commission expires: 1/2/2002

101 Public Notice

The Herald News
756-2109 or 547-2109
Fax 756-1003

PUBLIC HEARING

The Cloverport Planning & Zoning Commission will hold a public hearing on June 5, 2000 at 10:00 a.m. at City hall. The purpose of this hearing will be to receive public input from property owners regarding the re-zoning of Lots 2,5,6,7 & 8 of the former Irby Acres from Agriculture to C-2 Commercial.

Any questions may be addressed to Cloverport City Hall at 270/788-6632.

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

21c

NOTICE OF FORFEITURE SALE

Pursuant to Criminal file Numbers: 98-CR-00055, 99-CR-00100, 99-CR-00022, 97-CR-0655, 97CR-00060, 98-F-00137, 97-F-00091, 97-M-00595, 98-M-0070. 2000-M-00124

District and Circuit Court filed, it is ordered that I sell at Public Auction the following items:

1 22 cal. Marlin Rifle
1 12 gauge Winchester Model 37
1 357 Mag Smith and Wesson Piston
1 Ruger MK@ 22 cal. Pistol
1 20 gauge Mossberg Model 185
1 12 gauge Model 67L Stevens
1 Stevens double barrell 12 gauge Model 311 A
1 Winchester 22 cal. Model 150 rifle
1 Revelaton 22 cal. Model 105M
1 Essex 16 gauge
1 357 Taurus Pistol
1 Winchester 30-30 Model 94 w/scope
1 Remington 22 cal.
1 Interarms 9MM
1 Lorcin 25 cal.
1 Dan Wesson 357 Magnum
1 H & R 22 cal. Model 949

Said sale shall be at the Breckinridge County Courthouse in Hardinsburg, KY and said sale shall be held on the 27th day of may, 2000 at 9:00 a.m. The terms of said sale shall be cash or check approved by the Breckinridge County Sheriff.

Bobby D. Kennedy, Sheriff 19-21c

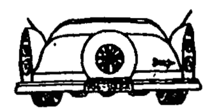
PUBLIC NOTICE- Hershell Carwile will be responsible for debts in his name ONLY and none incurred by Virginia L. (Jenny) Carwile. Effective immediately. 21-23p.

104 Lost & Found

-LOST-

Male Husky-mix, gray & black, approx. 100 lbs. Wearing choker collar & red bandana. Very friendly. Answers to "Bear". Missing from Cody Lane Area in Hardinsburg. Call 756-0135 or 756-2109.

105 Cars



TAYLOR USED CARS

Hardinsburg
756-5252
SEE
Lovel King

1997 Dodge Neon, 4 dr.
1997 Dodge Stratus, 4 dr.
1997 Pontiac Gr. Am, 4 dr.
1996 Pont. Bonneville, 4 dr
1995 Pont. Grand Prix,2dr.
1988 Pont. Sunbird, 4 dr.
1987 Ford T-Bird, 2 dr.
TRUCK
1998 Ford F-150 ,4wd
1996 Ford Explorer, 4 x4
1996 Ford Windstar, 7 pass.
1995 Jeep Gr. Cherokee, 4x4
1994 Chevy Conversion Van
1989 Ford Conversion Van
1988 Ford Ranger, x-cab
1985 S10, 4wd

FOR SALE Minivan, V6 clean, redu sale, $2,0 Cutlass Cie power. S Offer. C Basham. 2

FOR SALE LeSabre, 4 white, exce V6, autom $6,295. Jolly. 21-2

T

FOR SALE Eddie Ba leather s maroon ir Call 756-2

1995 DC loaded, 3 63,000 mi Call 270- ton., 21p

'88 DAKC am/fm c o.b.o.; '8 66k actua $6,800. Cummin

89 1 TON 454 Eng aluminur new pain Garage k after 6 p 21p

FOR S Jimmy air, pow locks, A -road $4,500. Drane.

FOR S Ford, 35 13 spe sion, 2 heavy t Call Br days 7 756-68

AFFIDAVIT OF PUBLICATION OF NOTICE

Affiant, being first duly sworn, states as follows:

1. Affiant is employed by JIM PAXTON, publisher of the newspaper THE PADUCAH SUN, as its CLASSIFIED SALES REP.

2. THE PADUCAH SUN is a newspaper of general circulation within the City of PADUCAH, County of MCCRACKEN, Commonwealth of Kentucky, and surrounding areas. It is published DAILY.

3. A notice, a true copy of which is attached hereto, was published in said newspaper on the 17 day of MAY, 2000.

Earl Lopez 5/17/00

Subscribed, sworn to and acknowledged before me by CASSIDY KINSEY on this 17 day of MAY, 2000.

Cassidy J. C. Kinsey
Notary Public, Ky. State at Large
My commission expires: AUGUST 11, 2003

06/27/03 16:07 FAX

Classified

4	$10.00	$16.40	$21.00	$28.00	$32.00	$38.40	$39.20	[illegible]
5	$1[illegible]	$20.50	$27.00	$36.00	$40.00	$48.00	$49.00	[illegible].50
6	$15.90	$24.60	$32.40	$43.20	$48.00	$57.60	$58.80	$113.40
7	$1[illegible]	$28.70	$37.80	$50.40	$56.00	$67.20	$68.60	[illegible]32.30

1. Announcements

101 Death Notice
102 Funeral Directors
106 Card of Thanks
107 In Memorium
108 Public Auction
109 Legal Notice
110 Commissioner's Sale
111 Sheriff's Sale
112 Lodges
113 Special Notice
114 Personal
115 Travel & Tours
116 Transportation
117 Lost & Found
118 Happy Ads
119 Public Notice
122 Free For The Taking

2. Employment

224 Domestic/Child Care
227 Medical Help Wanted
228 General Help Wanted
229 Sales Help Wanted
230 Office Clerical
231 Management/Trainees
232 Club-Restaurant Help
234 Mechanical-Technical

5. Merchandise (Con't)

554 Good Things To Eat
555 Business Equipment
556 Building Material
557 Musical Merchandise
558 Radio-TV-Stereo
559 Computers & Supplies
560 Miscellaneous For Sale
561 Household Goods
562 Antiques
563 Yard-Garage Sales
564 Sporting Goods
565 Cemetery Lots/Monuments
566 Wanted To Buy

6. Real Estate - Rent

667 Boarders Wanted
668 Rooms For Rent
669 Apartments For Rent
670 Houses For Rent
671 Mobile Homes For Rent
672 Farm Land For Rent
673 Mobile Home Lots For Rent
674 Business Property For Rent
675 Office Space For Rent
676 Resort Property For Rent
677 Wanted To Rent

7. Real Estate - Sales

IN MEMORIAM

5751: Designed for comfort and style, this free-flowing dress comes in two sleeve lengths and can be belted or not. Half Sizes. SIZE A 14½ to 24½ included.

Advertising Dept.

DIAL 575-8700

To place your WANT AD MONDAY THRU FRIDAY 8:00 A.M. TO 4:30 P.M.
IN-COLUMN DEADLINES
Sun.-Mon. ......3 p.m. Friday
Tues.-Sat. ....12 Noon Previous Day

DAILY CONSECUTIVE RATES
Apply Per Line/Per Day (2 LINES MINIMUM)

1 Day ....$2.65 Per Line
2 Days ....$2.05 Per Line
3-4 Days ......$1.80 Per Line
5-6 Days ......$1.60 Per Line
7 Days ....$1.40 Per Line
14 Days ....$1.35 Per Line

108 PUBLIC AUCTION

PUBLIC AUCTION
SAT., MAY 20, 2000
9:00 A.M.
500 N. 12TH ST.
"Folks, more of previous merchandise"
1993 Blazer, 2 door, 4 WD, 29,XXX miles; Oak hall tree/seat; Governor Winthrop secretary; 2 nice old oak rockers; dbl. bed (dark wood); brass covered trunks; dainty leg serving piece; collection of animal & eagle statuary; binoculars; sword; ammo; LC Smith dbl. 20 gauge (dbl. trigger, plain extractor & near mint); Marlin 357 lever action, looks unfired; H-

442-2100
Robert Griffin, Auctioneer ©Sun '00

108 PUBLIC AUCTION

Col. Paul Wilkerson & Sons
Real Estate & Auction
Lowes, Kentucky
674-5659 or 674-5523

MARTHA McGEE
Auctioneer 655-7303
Arlington, KY 655-2851

DOUBLE D AUCTION CO.
Donald (Deb) Rickman
Auctioneer 527-8909

JAMES R. Cash, The Auctioneer & Real Estate Broker. 270-623-8466/6236388.

PHYLLIS HAM, Auctioneer
434 N. 12th 443-2096

109 LEGAL NOTICE

ADVERTISEMENT FOR BIDS

Sealed bids for Modernization Project KY36P025-906 (1999) will be received by The Lyon County Housing Authority, on June 1, 2000, at 1:00pm prevailing time and then at said office publicly opened and read aloud. The estimated value of the project is between $75,000 and $100,000.
The Information for Bidders, Form of Bid, Form of Contract, Drawings, Specifications, and Forms of Bid Bond, Performance and Payment Bond, and other contract documents may be examined at the following locations:

109 LEGAL NOTICE

NOTICE

On March 21, [illegible]0, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.
Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, PO Box 615, Frankfort, Kentucky 40602.

ON & after this date, May 17, 2000, I will not be responsible for any debts made by anyone other than myself.
Randy D. Hamby
1919 Powell St.
Paducah, KY

113 SPECIAL NOTICE

PUBLIC

Pursuant to Application N
The Natural Resources and
Cabinet, Division of Waste
an application for renewa
Chemicals, Inc.
The applicant proposes to e
permit no. 079-00009 to Oct
The name and address of th
Air Products and
412 North M
Calvert City
Contact Person: R. S.
The permit application is
following address:
Division of Wast
Solid Was
14 Reill
Frankfort,
The application and related
at the Division of Waste Ma
between 8:30 AM and 4:00
ment only. To make an ap
request to Maria Wood at
desired review date. Requ
564-9232 or mailed to Ms.
Anyone wishing to make
them in writing to Carol

AFFIDAVIT OF PUBLICATION OF NOTICE

Affiant, being first duly sworn, states as follows:

1. Affiant is employed by The Crittenden Press ~~publisher~~ Inc. of the newspaper The Crittenden Press, as its publisher.

2. The Crittenden Press is a newspaper of general circulation within the City of Marion, County of Crittenden, Commonwealth of Kentucky, and surrounding areas. It is published Each Thursday

3. A notice, a true copy of which is attached hereto, was published in said newspaper on the 18th day of MAY, 2000.

Subscribed, sworn to and acknowledged before me by Chris Evans on this 18th day of May, 2000.

Notary Public, Ky. State at Large
My commission expires: 2.7.2004

CL

General For Sale

INSULATION SAVE on utility bills, free estimates, experienced and insured. Call Tommy at 965-2605, Wright's Insulation. (45t-25-p)

RAILROAD TIES at Randall's Repair. 965-2383. (21-tfc)

LUMBER – band sawed, poplar, red cedar, cypress or oak. Days 836-2014, nights 667-6265 or 965-9818. (24-tfc)

DELTA TOOL BOX, for small pickup, like new, $100. Call 965-2712. (4t-45-p-i)

TRAILERS OF ALL SIZES, enclosed, stock and dump trailers available for rent or sale. 16-ft. gooseneck stock trailer for sale. Trailer parts and accessories available. Installation of hitches and gooseneck plates. Corral panels also available, 965-2902. (2t-45-c)

HUGE SAVINGS on three arch type steel buildings. Customers canceled order. 25x30, 35x50. Ready for immediate delivery. Save thousands. Call 1-800-222-6335. (2t-45-p)

TWO person open base kayak/canoe, two paddles, two lifejackets, $400 OBO. Call 965-3693. (2t-45-p)

SEVEN piece dinette set, $35, 988-4726. (2t-45-p)

300 gallon diesel gas tank on stand, 965-3911. (2t-45-p)

WOLFE Sunquest 24 R tanning bed, $1,000; two twin beds; dresser; antique oak washstand; two bar stools; white Hoosier cabinet, 965-3605. (1t-45-p)

BEDROOM SUITE includes dresser, mirror, chest, headboard, nightstand and mattress set, full size, $300, Bebout, 965-2323. (1t-45-)

FOUR SNAPPER riding mowers, (1) 11 hp, (2) 8 hp, electric start, one manual start, $400 for all, 988-3945. (1t-45-p)

CABLE CUSTOMERS: Get your local stations FREE. Satellite programming starting at $19.99/mo. Call Satellite Express at 1-800-862-8127 for details. (4t-48-p)

BROWNING 12 gauge pump shotgun; Napa 295 amp. welder, 965-0999 or 965-9048. (1t-45-p)

EPSON LQ570 printer, like new, used very little, $50. Call or stop by The Crittenden Press, 965-3191, 125 E Bellville St., Marion.

FREE WOODEN PALLETS at The Crittenden Press. Stop by 125 E. Bellville in Marion, Kentucky.

END ROLLS OF NEWSPRINT - great for all the uses of old newspapers without the mess of black ink. Contact The Crittenden Press at 965-3191.

This job will be a temporary intermittent position not to exceed one (1) year. Salary will depend on the experience of the person selected, but no less than $7.98 per hour.

Applications will be accepted at the Crittenden County FSA office at 118 E. Bellville St., Marion, Ky., 42064, or can be mailed to the same address.

USDA is an equal opportunity employer and prohibits discrimination in its programs and activities on the basis of race, color, national origin, gender, religion, age, disability, political beliefs, sexual orientation and marital or familial status. (2t-45-c)

Give your life a makeover! Start an AVON business. Call Gwen, 1-888-413-1072. (4t-47-p)

DEPENDABLE person needed to clean men's bath house in Clay area, 965-9024. (2t-45-p)

POST OFFICE CAREERS – start $14.08 per hour plus benefits. For exam and application info. call 219-661-2444, ext. KY 190, 8 a.m.-10 p.m., seven days, www.cnijobhelp.com. (4t-47-p)

WANTED: Full charge bookkeeper for permanent, full-time position. Must have extensive knowledge of Quick Books software. Only experienced need to apply. Please call 365-1210 for appointment. (2t-46-p)

SERVICE COORDINATOR needed to work with severely emotionally disabled children in Caldwell, Crittenden and Lyon Counties. Requires minimum of Bachelor's degree in a behavioral science (social work, psychology, human services, sociology, or special education) and a one year experience in case management or working directly with children. Must reside in one of the assigned counties. Pickup an application and job description at 1507 S. Main St., or send letter and resume to Personnel, Pennyroyal Center, P.O. Box 614, Hopkinsville, Ky., 42241. (2t-46-c)

LEGAL SECRETARY POSITION OPENING

An immediate opening for a legal secretary. Legal and/or secretarial experience required. Must be computer literate. Experience with the use of WordPerfect preferred. Send resume to Stout Law Office, P.O. Box 81, Marion, Ky., 42064, Attn: Doris. (2t-46-c)

Employment Wanted

WILL PROVIDE loving care sitting with elderly. References provided. Ask for Barbara, 965-9170 from 4-9 p.m. (2t-46-p)

WANTED HOUSES to clean. Honest and dependable. Call 965-0106 ask for Marie or leave a message at 965-2294 or 965-2926. (1t-45-p)

WILL CLEAN houses. Dependable, references upon request, 965-9775. (1t-45-p)

HAY CREW AVAILABLE, out of field or just relocating bales - round or square. Ser-

F" S at d Y 1 C p 4

ory

...nstruction • Cleaning

...CH'S HEATING & COOLING — Electri-... and Appliance installation and repair. ...ill Rich Rozwalka at 965-4451. (47-tfc)

...RTER & SONS EXCAVATING– Cus-...n dozing and trackhoe work, clearing ...nds, waterways, basements, lakes. ...rey Porter, 988-3218, Porter & Sons; ...8-2899.(31-tfc)

...I BACK. For all your dozer needs. Call ...8-2704, years of experience. (4t-45-p)

...ARPET AND UPHOLSTERY CLEANING, ...utos, homes, businesses, NATJO ser-...ces, 965-5083. (3t-46-p)

...USTOM hay cutting. Call 545-3448 after ...p.m., or leave a message. (4t-48-p)

...USH HOGGING – nothing too small or ...o large. Call Brian King, 988-2821. (4t-...8-p)

Crittenden District Court
(1t-45-c)

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility; and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, Kentucky, 40602. (1t-45-c)

Notices

PELL GRANT MONEY is now available for people who qualify for Cosmetology Apprentice Instructor, and Nail Technicians. Call 667-5596 for an appointment at Head's Beauty College Providence while federal funds are available. (49-tfc)

CHECK YOUR AD

Advertisers: Be sure to check the first insertion of ads for any error. The Crittenden Press will be responsible for only one incorrect insertion. Report any errors immediately so necessary corrections can be ... The Crittenden Press 965-3191

HERALD LEDGER

P.O. Box 577 • 214 Commerce St. • 502-388-2269 • Eddyville, Kentucky 42038

COUNTY OF LYON
STATE OF KENTUCKY

AFFIDAVIT OF PUBLICATION

Selena Ward, being first duly sworn that he/she is ad. Manager of the Herald Ledger, that the attached notice was published in said newspaper on 5-24-00

Selena A Ward
(Signed)

Subscribed and sworn to me this 9 day of June ~~19~~ 2002

Jayne Stark
(NOTARY PUBLIC)

My commission expires on the 3 day of 2 ~~19~~ 2000.

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, Kentucky 40602.

LEGAL NOTICE

Notice is hereby given that The Bank of Lyon County, 153 West Main, Eddyville, Kentucky has made application to the Federal Deposit Insurance Corporation for merger with the following banks: Bank of Livingston County, Tiline, Kentucky; Dees Bank of Hazel, Hazel, Kentucky; Peoples Bank of Murray, KY, Murray, Kentucky; Broadway Bank and Trust, Paducah, Kentucky; Owensboro National Bank, Owensboro, Kentucky; Alliance Bank, Somerset, Kentucky; Citizens Deposit Bank of Calhoun, Kentucky, Calhoun, Kentucky; First & Peoples Bank, Springfield, Kentucky, Springfield, Kentucky; HNB Bank, NA, Harlan, Kentucky; Southern Deposit Bank, Russelville, Kentucky; Bowling Green Bank and Trust Company, NA, Bowling Green, Kentucky; First City Bank and Trust Company, Hopkinsville, Kentucky; Jefferson Banking Company, Louisville, Kentucky; The New Farmers National Bank of Glasgow, Glasgow, Kentucky; and Peoples Commercial Bank, Winchester, Kentucky. All of the aforementioned banks are directly or indirectly owned by Area Bancshares Corporation. Following the merger, The Bank of Lyon County will change its name to "Area Bank". Area Bank's main office will be located in Owensboro, Kentucky.

It is contemplated that all offices of the above named institutions will continue to operate with the exception of the main office location of Bank of Livingston County, 1543 Tiline Road, Tiline, Kentucky, which location will close on August 18th, 2000.

Any person wishing to comment on this application may file his or her comments in writing with the Regional Director (DOS) of the Federal Deposit Insurance Corporation at its Regional Office at 5100 Poplar Avenue, Suite 1900, Memphis, Tennessee 38137, not later than June 5th, 2000. The nonconfidential portions of the application are on file in the Regional Office and are available for public inspection during regular business hours. Photocopies of information in the nonconfidential portion of the application file will be made available upon request.

Paste copy of advertisement on this margin.

PROOF OF PUBLICATION

Mayfield, KY

In Account With

The Mayfield Messenger

Mayfield, KY 42066

Title of Advertising: Classified Legal

2X 4" @ $5.59	8"	44.72

Personally appeared before me, Eric Hoffman, Publisher of The Mayfield Messenger, a daily newspaper published in Mayfield, Graves County, Kentucky, and on his oath says that the above are the true charges for advertising, which appeared in The Mayfield Messenger on the following dates:

5-17-00

Signed Eric Hoffman
Publisher of The Mayfield Messenger

Subscribed and sworn to before me, Carolyn Williams, a Notary Public in Mayfield, Graves County, Kentucky, by Eric Hoffman this

Signed Carolyn Williams

My Commission Expires

MY COMMISSION EXPIRES
AUGUST 12, 2001

2X4 Sullivan Mt Joy - Legal

NOTICE

On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.

Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P.O. Box 615, Frankfort, KY 40602.

RECEIVED

JUN 08 2000

PUBLIC SERVICE COMMISSION

HOGAN & HARTSON L.L.P.

COLUMBIA SQUARE
555 THIRTEENTH STREET, NW
WASHINGTON, DC 20004-1109
TEL: (202) 637-5600
FAX: (202) 637-5910
WWW.HHLAW.COM

June 2, 2000

Mr. Martin Huelsmann
Executive Director
Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602

Re: <u>Amendment of Official Service Lists in KPSC Case Nos. 99-429, 99-354, 2000-095, and 2000-116</u>

Dear Mr. Huelsmann:

I write to request amendment of the official service lists in Kentucky Public Service Commission (Commission) proceedings Case Nos. 99-429, 99-354, 2000-095, and 2000-116. Regulatory counsel for Big Rivers Electric Corporation has relocated. Please amend the relevant entries on each service list for Douglas L. Beresford, Esq. The appropriate entry in each service list should read:

Douglas L. Beresford
HOGAN & HARTSON L.L.P.
555 Thirteenth Street, N.W.
Washington, D.C. 20004-1109
Telephone: (202) 637-5819
Facsimile: (202) 637-5910

\\\DC - 79999/630 - #1103808 v1

A copy of this request has been served on all parties in the listed proceedings. Should you have any questions, please do not hesitate to contact the undersigned. Thank you for your assistance.

Sincerely,

Douglas L. Beresford

Douglas L. Beresford

cc: All Parties
Ms. Susan Hutchinson, KPSC Staff

\\\DC - 79999/630 - #1103808 v1

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

June 5, 2000

To: All parties of record

RE: Case No. 1999-429

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

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42419 0024

John Stapleton
663 Teton Trail
Frankfort, KY 40601

Honorable Iris Skidmore
Honorable Ronald P. Mills
Counsel for Natural Resources and
Environmental Protection Cabinet
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

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

Honorable James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback &
Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, KY 42302 0727

Honorable Douglas Beresford
Counsel for Big Rivers Electric
Long, Aldridge & Norman
Suite 600
701 Pennsylvania Avenue
Washington, DC 20004

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	))	CASE NO. 99-429

O R D E R

On May 22, 2000, the Attorney General ("AG"), filed a motion for an extension of time to file his data requests in the above action, from May 19, 2000 to May 22, 2000.

The Commission, having considered the motion and being otherwise sufficiently advised, HEREBY ORDERS that the AG's request for a one-day extension of time to file his data requests is granted and the data requests are due on May 22, 2000.

Done at Frankfort, Kentucky, this 5th day of June, 2000.

By the Commission

ATTEST:

Executive Director

RECEIVED

MAY 2 2 2000

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE)
PLAN OF BIG RIVERS) Case No. 99-429
ELECTRIC CORPORATION)

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits these Requests for Information to Big Rivers Electric Corporation, to be answered by the date specified in the Commission's Order of Procedure, and in accord with the following:

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

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

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

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

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

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

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

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

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

Respectfully submitted,
A. B. CHANDLER, III
ATTORNEY GENERAL

/s/ Blackford

ELIZABETH E. BLACKFORD
ASSISTANT ATTORNEY GENERAL
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, KY 40601
(502) 696-5358

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that this the 22nd day of May, 2000, I have filed the original and ten true copies of the following with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 and Certify that this same day I have served the parties by electronically mailing same to David Spainhoward and James Miller at their respective e-mail addresses and by mailing a true copy of same, postage prepaid, to the following:

JOHN STAPLETON
633 TETON TRAIL
FRANKFORT KY 40601

HON IRIS SKIDMORE
HON RONALD P MILLS
OFFICE OF LEGAL SERVICES
FIFTH FLOOR
CAPITAL PLAZA TOWER
FRANKFORT KY 40061

DAVID SPAINHOWARD
VICE PRESIDENT BIG RIVERS ELECTRIC CORPORATION
P O BOX 24
HENDERSON KY 42420

HON JAMES M MILLER
SULLIVAN MOUNTJOY STAINBACK & MILLER PSC
100 ST ANN STREET
P O BOX 727
OWENSBORO KY 42302

HON DOUGLAS BERESFORD
LONG ALDRIDGE & NORMAN
SUITE 600
701 PENNSYLVANIA AVENUE
WASHINGTON DC 20004

//Black//

ATTORNEY GENERAL'S REQUESTS FOR INFORMATION

1. The IRP mentions the addition of 62 MW of distributive generation on the Kenergy system. With respect to this addition please provide the following information:

a) The name of the customer that is adding the capacity;

b) The type of generator;

c) The fuel type and source;

d) The expected availability of this unit.

e) Will this be operated in a co-generation mode?

f) Will Kenergy be expected to supply back-up capacity when this unit is down?

g) Will planned outages of this unit be scheduled with Big Rivers and Kenergy?

2. On page I-9 of the IRP, reference is made to significant revenues be generated from sales of surplus energy received from the LEM contract. With respect to these sales:

a) Please supply the projected annual kWh sales and margins that were projected as a part of the workout plan, proposed and accepted by the Commission in Case No. 97-204.

b) Please supply the actual annual kWh sales and margins received by Big Rivers since the LEM contract has been in place and surplus energy has been sold off-system.

c) Please supply the projected annual kWh sales and margins that are included in the optimal IRP plan (case 5), and please explain any difference between these figures and those contained in the workout plan in Case No. 97-204.

3. On page I-14 of the IRP, reference is made to projected load growth contained in the IRP. With respect to projected load growth:

a) Please supply the actual peak loads and energy sales for the Big Rivers system, excluding the smelter loads, for each of the last 15 years.

b) Please provide the projected load growth, in both peak loads and energy sales, contained in the workout plan, proposed and accepted by the Commission in Case No. 97-204, and provide an explanation of why the projected growth figures in the IRP differ from those in the workout plan.

4. Please provide a detailed explanation of Big Rivers' and its three Cooperative's efforts, both current and proposed, to encourage distributive generation.

5. Please provide any written policy statement Big Rivers has adopted to encourage the distributive generation.

6. Is distributive generation being encouraged just for existing members, or are Independent Power Producers (IPP) that purchase no power from a cooperative being encouraged to provide power to the Big Rivers system. If IPPs are being encouraged as distributive generation, are they compensated at the cost of power to the member cooperatives?

7. The IRP considered only wind and biomass as renewable options. Please explain why Big Rivers has not considered low cost run-of-river hydro at the Cannelton and Smithland dams on the Ohio River, which are located in the Big Rivers service territory and which have significantly lower costs than the renewable options considered by Big Rivers.

8. The biomass option considered by Big Rivers was a plantation-grown biomass. Please explain why Big Rivers

did not consider the use of wood waste, primarily sawdust, which is readily available in large quantities in the Big Rivers service territory, at no cost or just the cost of transportation.

9. On pages IV-11 and 12 of the IRP, Big Rivers states that the two residential DSM programs considered are not cost effective. Please provide all of the calculations, assumptions and workpapers that were used to generate the costs for the programs as related in the IRP and to support the conclusions that were reached.

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC
ATTORNEYS AT LAW

May 23, 2000

RECEIVED
MAY 24 2000
PUBLIC SERVICE COMMISSION

Martin J. Huelsmann, Jr.
Executive Director
Public Service Commission of KY
211 Sower Blvd., P.O. Box 615
Frankfort, KY 40602-0615

Re: The Integrated Resource Plan of Big Rivers Electric Corporation,
PSC Case No. 99-429

Dear Mr. Huelsmann:

Enclosed are an original and ten copies of the response of Big Rivers Electric Corporation to the motion of the Attorney General for an extension of time. I certify that a copy of this response has today been mailed, postage prepaid, to each of the parties shown on the attached service list.

Sincerely yours,

James M. Miller

James M. Miller

JMM/ej
Enclosures

cc: Doug Beresford
David Spainhoward
Service List

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

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC CORPORATION)
CASE NO. 99-429

RESPONSE TO MOTION OF ATTORNEY GENERAL
FOR EXTENSION OF TIME

Big Rivers Electric Corporation has no objection to the extension of time requested by the Attorney General in her motion of May 23, 2000.

This the 23rd of May, 2000.

James M. Miller

James M. Miller
Mark Willis
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Street, P.O. Box 727
Owensboro, KY 42302-0727
(270) 926-4000

Douglas L. Beresford
Hogan & Hartson LLP
555 13th Street, NW
Washington, DC 20004-1109
(202) 637-5600

Counsel for Big Rivers Electric Corporation

Service List
PSC Case No. 99-429

Elizabeth Blackford, Esq.
Assistant Attorney General
Utility and Rate Intervention Division
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601

Office of the Attorney General of the Commonwealth of Kentucky

Iris Skidmore
Ronald P. Mills
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601

John Stapleton
Director of Energy NREPC
663 Teton Trail
Frankfort, KY 40601

Counsel for Natural Resources and Environmental Protection

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

RECEIVED

MAY 22 2000

PUBLIC SERVICE
COMMISSION

THE INTEGRATED RESOURCE)
PLAN OF BIG RIVERS) Case No. 99-429
ELECTRIC CORPORATION)

MOTION FOR EXTENSION OF TIME

Comes the Attorney General, by counsel, and moves the Commission to grant a one business day enlargement of time for the filing of data requests in the above action, from May 19 to May 22, 2000. In support thereof Movant states that Counsel and the expert consultant utilized herein were both preoccupied with the filing of testimony on the 18th in Case No. 00-056 and in preparation for participation in the Informal Conference on the 19th in Cases No. 00-056 and 00-079 and, therefore, failed to file the data requests herein in accord with the procedural schedule on the 19th. To preclude prejudice to Big Rivers, the Attorney General has served copies of the Data Requests on David Spainhoward and James Miller by electronic mailing, so that the requests will be received by Big Rivers on the same day as they would have had they been timely filed and by served only by mail.

Respectfully Submitted

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

NOTICE OF FILING AND CERTIFICATE OF SERVICE

I hereby give notice that this the 22nd day of May, 2000, I have filed the original and ten true copies of the foregoing with the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 and Certify that this same day I have served the parties by electronically mailing same to David Spainhoward and James Miller at their respective e-mail addresses and by mailing a true copy of same, postage prepaid, to the following:

JOHN STAPLETON
633 TETON TRAIL
FRANKFORT KY 40601

HON IRIS SKIDMORE
HON RONALD P MILLS
OFFICE OF LEGAL SERVICES
FIFTH FLOOR
CAPITAL PLAZA TOWER
FRANKFORT KY 40061

DAVID SPAINHOWARD
VICE PRESIDENT BIG RIVERS ELECTRIC CORPORATION
P O BOX 24
HENDERSON KY 42420

HON JAMES M MILLER
SULLIVAN MOUNTJOY STAINBACK & MILLER PSC
100 ST ANN STREET
P O BOX 727
OWENSBORO KY 42302

HON DOUGLAS BERESFORD
LONG ALDRIDGE & NORMAN
SUITE 600
701 PENNSYLVANIA AVENUE
WASHINGTON DC 20004

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602-0615
www.psc.state.ky.us
(502) 564-3940
Fax (502) 564-3460

B. J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

May 19, 2000

James M. Miller, Esq.
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Building
Post Office Box 727
Owensboro, Kentucky 42302-0727

RE: Case No. 99-429, Big Rivers Electric Corporation

Dear Mr. Miller:

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

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

Enclosure

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KENTUCKY 40602-0615
www.psc.state.ky.us
(502) 564-3940
Fax (502) 564-3460

B. J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

CERTIFICATE OF SERVICE

RE: Case No. 99-429
Big Rivers Electric Corporation

I, Stephanie Bell, Secretary of the Public Service Commission, hereby certify that the enclosed copy of the Commission Staff's data request in the above case was served upon the following by U.S. Mail on May 19, 2000.

Parties:

Mr. David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P.O. Box 24
Henderson, KY 42419-0024

Mr. James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback &
Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, KY 42302-0727

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

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

Ms. Iris Skidmore
Mr. Ronald P. Mills
Counsel for Natural Resources
And Environmental Protection
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Mr. Douglas Beresford
Counsel for Big Rivers Electric
Long, Aldridge & Norman
Suite 600
701 Pennsylvania Avenue
Washington, D.C. 20004

Stephanie J. Bell

Secretary of the Commission

Enclosure

COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN)
OF BIG RIVERS ELECTRIC) CASE NO. 99-429
CORPORATION)

COMMISSION STAFF'S REQUEST FOR INFORMATION
TO BIG RIVERS ELECTRIC CORPORATION

The Commission Staff requests that Big Rivers Electric Corporation ("Big Rivers") file an original and 6 copies of the following information, with a copy to all parties of record, by no later than June 19, 2000. Each copy of the data requested should be placed in a bound volume with each item tabbed. When a number of sheets are required for an item, each sheet should be appropriately indexed, for example, Item 1(a), Sheet 2 of 5. Include with each response the name of the person responsible for responding to questions relating to the information provided.

1. Describe the progress Big Rivers has made in identifying industrial customers suited for the load management plan described on page I-15 of the IRP.

2. Discuss how Big Rivers intends to encourage the use of distributed generation among its members, as was mentioned on page I-16 of the IRP. Has Big Rivers or its member cooperatives performed any case-by-case analysis of

the potential benefits of distributed generation additions, and if so, what were the results?

3. Pages IV-8 and 9 of the IRP discuss two voluntary curtailment programs, one by Florida Power and Light and one involving a "shared" savings approach during the period of interruption. Discuss Big Rivers' evaluations and any plans for both of these programs.

4. According to Page IV-11 of the IRP, "In the best of all worlds, Big Rivers would eliminate residential participation for DSM programs and repackage programs as "Customer Satisfaction' options offered to the customers." Discuss Big Rivers' plans, and those of its member cooperatives, relative to residential DSM programs and whether there are any intentions to reduce or eliminate residential participation.

5. For each recommendation made in the May 1995 PSC Staff Report on Big Rivers' 1993 IRP, discuss in detail and reference by section and page number how Big Rivers has addressed the recommendation in its latest IRP. For any recommendation that Big Rivers believes to be inapplicable because of subsequent events, so state and specifically explain why the recommendation is no longer applicable.

6. Explain whether the recently proposed purchase of LG&E Energy Corporation by PowerGen plc will change any of the plans discussed in the IRP.

7. One of the IRP's recommendations is that Big Rivers maintain an ongoing dialogue with other potential power suppliers regarding low cost energy

and capacity sources. Are there any new developments in that regard relative to power requirements for the 2004 to 2011 time frame?

8. Are there any significant effects from the merger that resulted in Kenergy Corp. and a rate reduction that could impact the conclusions or results of the 1999 IRP?

9. Discuss any significant effects anticipated from tariffs filed by Big Rivers since the Power Requirements Study was finalized in September 1999, and how those effects could impact the conclusions or results of the 1999 IRP.

10. Reference is made to Rate Schedule 10 on page I-2 of the IRP. Is any load presently being served on Rate Schedule 10? Are any new load additions expected to be served on Rate Schedule 10 by the end of calendar year 2000? If yes to either question, provide the size of the loads.

11. If 62 MW of generation by a Kenergy customer does not occur as anticipated, Big Rivers is expected to become capacity deficient by 2004.

a. Given the current status of the market for combustion turbines, will Big Rivers be able to install new capacity before 2004?

b. If by September 1, 2000, Big Rivers determines that the 62 MW of generation is not going to be installed, identify the specific actions that will be required, and the timeline for these actions, to ensure that additional capacity is installed by 2004.

12. Refer to page I-14 of the IRP. Provide a brief description of the types of changes to SEPA that have been the subject of congressional discussions.

13. Refer to page II-5 of the IRP. Provide the specific expiration dates for each of Big Rivers' three existing wholesale power sales contracts.

14. Refer to page III-5 of the IRP under "Unit Purchases" which discusses the planned merchant plant activity in or near Big Rivers' service territory. Provide updates to any of this information to reflect events that have occurred since the IRP was prepared.

15. Refer to page IV-12 of the IRP regarding Burns & McDonnell's DSM recommendations to Big Rivers. To date, identify any actions Big Rivers has taken in response to those recommendations.

16. Refer to Part VII of the IRP titled "Conclusion and Three Year Plan." Explain the significance of three years. Identify if this is related to Big Rivers' cycle for preparing its Power Requirements Study ("PRS").

17. In its 1999 PRS, Big Rivers identifies Woods and Poole Economics, Inc. as one of its data sources. Other utilities regulated by the Commission have recently begun using this same firm. Provide the date when Big Rivers been using this firm in conjunction with the development of its PRS.

18. Page I-4 of the IRP indicates that "the LEM contract includes liquidated damages for non-delivery." Discuss how the damages that would be payable under the contract if LEM fails to deliver the required power would be calculated. Should the non-performance occur in a period of escalating prices, such as that experienced during the summers of 1998 and 1999, explain whether the damages would include some portion of the premium that Big Rivers might

have to pay for power at market prices and how that portion would be determined.

19. Page I-7 of the IRP refers to the recommendation that Big Rivers should study the implementation of a combined commercial and industrial DSM plan and that approval of Rate Schedule 10 is a solid first step in the implementation of the plan. Explain how Rate Schedule 10 aids in implementing the DSM plan.

Respectfully submitted,

Richard Raff
Staff Attorney

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF	)	
BIG RIVERS ELECTRIC COPRPORATION	)	**CASE NO. 99-429**

KENTUCKY DIVISION OF ENERGY'S FIRST REQUEST FOR INFORMATION TO THE BIG RIVERS ELECTRIC CORPORATION

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

1. The volume submitted to the Commission in this case is titled the "1999 Integrated Resource Plan for Big Rivers Electric Corporation." The first sentence of the Executive Summary states that this Integrated Resource Planning Study for Big Rivers Electric Corporation was prepared by Burns & McDonnell to meet the requirements of the Commission's IRP regulation and to serve as a guide for Big Rivers in planning its resources to meet future system demands. The 3-year plan (pp. I-15 to I-16) takes the form of a set of recommendations from the consultants to Big Rivers. The second part of the volume consists of the "1999 Power Requirements Study for Big Rivers Electric Corporation," which was also prepared by Burns & McDonnell. Has Big Rivers adopted the Integrated Resource Planning Study and the 1999 Power Requirements Study as its 1999 integrated resource plan?

2. The cover of the volume includes a logo and the phrase, "A Touchstone Energy^{SM} Partner." Please describe the benefits or services Big Rivers presently receives by virtue of being a Touchstone Energy^{SM} Partner.

3. Please describe the terms of Big Rivers' arrangement with LG&E Energy Marketing (LEM), whereby Big Rivers owns but does not operate generating facilities. If certain contracts or other documents (in part or in whole) would shed light on this question, please provide a copy of the documents or any relevant pages.

4.a. Is Big Rivers aware of any other member/customers planning to implement self-generation or cogeneration, other than the Kenergy member/customer that is planning to install 62 MW of power generation in spring 2001?

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

5. Why is the Voluntary Commercial/Industrial Load Management Program included in the Power Supply Screening Analysis (Part III) rather than in the Demand-Side Management Screening Analysis (Part IV)?

6. Point #4 of the three-year plan on page I-16 and page VII-3 states, "Big Rivers should encourage the use of distributed generation among its members to lower peak demands and energy requirements and provide Big Rivers with greater flexibility in its power supply operations."

a. Does Big Rivers have any programs now in effect, or in the planning stage, to encourage member/customers to install distributed generation systems? If so, please describe these programs and/or program plans.

b. It seems to the Kentucky Division of Energy (KDOE) that strategic conservation would also lower peak demands and energy requirements and provide Big Rivers with greater flexibility in its power supply operations. Why does the IRP recommend against strategic conservation, even though it appears to have beneficial characteristics and impacts similar to those of distributed generation?

7.a. Has Big Rivers considered the potential impact of net metering, as instituted in 30 other states and as outlined in legislation introduced in the U.S. Congress by Rep. Jay Inslee, which would require all retail electric suppliers to offer net metering service to retail customers that generate electricity using certain qualified technologies? [The proposed national legislation is titled the "Home Energy Generation Act."]

b. If net metering were to be instituted in the service area of Big Rivers and its member distribution cooperatives, what would be the estimated impact on energy use and demand over the next 15 years?

8.a. Has Big Rivers availed itself of information from organizations such as E Source, which is a source of comprehensive information on energy efficiency technologies and programs?

b. To what extent, if any, was information from such sources used in developing the IRP?

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

b. If so, what is the size of these potential DSM resources?

10. Has Big Rivers estimated the square footage of residential, commercial, and industrial floor space that is being newly constructed each year in its service area? If so, what are the estimated square footage figures?

11. Has Big Rivers surveyed the energy efficiency of the range of types of new buildings being constructed in its service area? If so, please provide the results of this analysis.

12. Please provide a copy of the DSM study undertaken by Big Rivers and prepared by R.W. Beck in 1995.

13. If Figure IV-1 is not an original drawing, please provide the reference.

14. The first paragraph on page IV-5 implies that Burns & McDonnell performed an analysis of certain DSM programs considered in the 1995 study by R.W. Beck. Please provide a copy of this analysis, including any working papers.

15. The first two paragraphs under "Load Growth Options" on page IV-5 discuss programs that would provide financial incentives to encourage member/customers to switch from natural gas furnaces and water heaters to their electric counterparts.

a. Please define and explain what the IRP means by "market transformation" in this context.

b. If such a fuel-switching incentive program were to be instituted for a number of years (with some measurable effect on the market) and were then terminated, would Big Rivers expect member/customers to continue purchasing electric space and water heating appliances in the absence of the incentives?

16.a. Which cost effectiveness test (e.g., TRC, RIM, UC or PC) is being referenced in the last paragraph on page IV-5?

b. The same paragraph refers to a "preliminary analysis." Please provide a copy of this analysis, including any working papers.

17. Which cost effectiveness test is being referenced in the last paragraph on page IV-11?

18. Does Big Rivers or its member distribution cooperatives presently have any programs to promote improved energy efficiency among their member/customers? If so, please describe these programs, including quantitative information about their energy impacts if available.

19. While Section IV of the IRP focuses on the effects of various types of DSM programs on the utility company, it does not appear to consider the question of which programs would be most beneficial to member/customers in terms of reduced energy bills.

a. In view of the fact that the purpose of a cooperative is to benefit its member/ customers, why do the discussion and recommendations on pages IV-3 through IV-5 and pages IV-11 through IV-12 appear to leave the benefits for member/customers out of the analysis?

b. Why isn't the total resource cost (TRC) test used as the primary criterion for evaluating and comparing demand-side and supply-side resource options?

20. The provisions at the bottom of page IV-7 refer to load management contracts. The first provision would require the member/customer to agree to remain a customer for at least 7 years from the date of signing the contract. In view of the present status of the debate on electric industry restructuring, is it realistic to expect many customers to agree to this provision?

21. Does Big Rivers plan to make any improvements to and/or more efficient utilization of its transmission and distribution (T&D) system during the 2000-2013 time frame?

[Reference 807 KAR 5:058 Section 8(2)(a) and Section 5(4)] If so, please provide a quantitative description and schedule of these improvements.

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

a. Has Big Rivers used the LIRP approach to determine whether any planned transmission or distribution projects could economically be deferred? If so, please provide the results of the studies.

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

23. Please provide a detailed description of the method Big Rivers and its member distribution cooperatives use to determine how much to charge a new residential, commercial, or industrial customer to hook up their building to the grid. Please explain why this particular method or formula was chosen.

Respectfully submitted,

Ronald P. Mills

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

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing KENTUCKY DIVISION OF ENERGY'S FIRST REQUEST FOR INFORMATION TO THE BIG RIVERS ELECTRIC CORPORATION was mailed, first class, postage prepaid, the 18th day of May, 2000, to the following:

David A. Spainhoward
Vice President
Big Rivers Electric Corporation
P. O. Box 24
Henderson, KY 42419-0024

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

Hon. James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
P.O. Box 727
Owensboro, KY 42302-0727

Hon. Douglas Beresford
Counsel for Big Rivers Electric
Long, Aldridge & Norman
701 Pennsylvania Avenue, Suite 600
Washington, DC. 20004

Ronald P. Mills
Ronald P. Mills

Paul E. Patton, Governor

Ronald B. McCloud, Secretary
Public Protection and
Regulation Cabinet

Martin J. Huelsmann
Executive Director
Public Service Commission

Commonwealth of Kentucky
Public Service Commission
211 Sower Blvd.
Post Office Box 615
Frankfort, Kentucky 40602-0615
www.psc.state.ky.us
502-564-3940
Fax 502-564-3460

B.J. Helton
Chairman

Edward J. Holmes
Vice Chairman

Gary W. Gillis
Commissioner

May 10, 2000

James M. Miller, Esq.
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Building
Post Office Box 727
Owensboro, Kentucky 42302-0727

RE: Big Rivers Electric Corporation
Case No. 99-429
Petition for Confidential Protection

Dear Mr. Miller:

The Commission has received the petition filed March 21, 2000, on behalf of Big Rivers Electric Corporation to protect as confidential the information in the Company's 1999 integrated resource plan. A review of the information has determined that it is entitled to the protection requested on the grounds relied upon in the petition, and it will be withheld from public inspection.

If the information becomes publicly available or no longer warrants confidential treatment, you are required by 807 KAR 5:001, Section 7(9)(a) to inform the Commission so that the information may be placed in the public record.

Sincerely,

Martin J. Huelsmann
Executive Director

COMMONWEALTH OF KENTUCKY
PUBLIC SERVICE COMMISSION
211 SOWER BOULEVARD
POST OFFICE BOX 615
FRANKFORT, KY. 40602
(502) 564-3940

April 28, 2000

To: All parties of record

RE: Case No. 1999-429

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

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42419 0024

John Stapleton
663 Teton Trail
Frankfort, KY 40601

Honorable Iris Skidmore
Honorable Ronald P. Mills
Counsel for Natural Resources and
Environmental Protection Cabinet
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

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

Honorable James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback &
Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, KY 42302 0727

Honorable Douglas Beresford
Counsel for Big Rivers Electric
Long, Aldridge & Norman
Suite 600
701 Pennsylvania Avenue
Washington, DC 20004

COMMONWEALTH OF KENTCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF BIG RIVERS ELECTRIC CORPORATION	))	CASE NO. 99-429

O R D E R

The Commission, on its own motion, hereby initiates its review of the Integrated Resource Plan ("IRP") of Big Rivers Electric Corporation ("Big Rivers") filed on March 21, 2000 pursuant to 807 KAR 5:058. Big Rivers is required by 807 KAR 5:058, Section 10, to publish in a form prescribed by the Commission, notice of its filing in a newspaper of general circulation in its service areas. The notice must be published within 30 days of the filing date of this IRP. The Commission finds that the following format should be used when publishing notice of the IRP filing:

> On March 21, 2000, Big Rivers Electric Corporation filed its 1999 Integrated Resource Plan with the Kentucky Public Service Commission. This filing includes the most recent load forecasts of Big Rivers Electric Corporation and a description of the existing and planned conservation programs, load management programs and power supplies it intends to use to meet forecasted requirements in a reliable manner at the lowest possible cost. Any interested person may review the plan, submit written questions to the utility, and file written comments on the plan.
>
> Any person interested in participating in the review of this Integrated Resource Plan should, within 10 days of the publication of this notice, submit a motion to intervene to: Martin Huelsmann, Executive Director, Public Service Commission, P. O. Box 615, Frankfort, Kentucky 40602.

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

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

IT IS THEREFORE ORDERED that:

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

2. The procedural schedule set forth in Appendix A shall be followed in this case.

Done at Frankfort, Kentucky, this 28th day of April, 2000.

By the Commission

ATTEST:

Executive Director

APPENDIX A

APPENDIX TO THE ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 99-429 DATED APRIL 28, 2000

Initial interrogatories to Big Rivers shall be filed no later than 05/19/00

Big Rivers' responses to initial interrogatories shall be filed no later than 06/19/00

Supplemental interrogatories to Big Rivers shall be filed no later than 07/18/00

Big Rivers' responses to supplemental interrogatories shall be filed no later than 08/18/00

An informal conference will be held at 10:00 a.m., Eastern Daylight Time, in the Commission's offices at 211 Sower Boulevard, Frankfort, Kentucky, for the purpose of discussing issues related to Big Rivers' 1999 IRP filing 09/08/00

Intervenors shall have the option of filing written comments on issues related to Big Rivers' 1999 IRP filing no later than 10/02/00

Big Rivers shall have the option to file written comments in reply to any written comments from intervenors no later than 10/27/00

Big Rivers
Electric Corporation

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
502·827·2561
www.bigrivers.com

March 21, 2000

Mr. Martin Huelsmann
Executive Director
Public Service Commission
211 Sower Boulevard
P. O. Box 615
Frankfort, KY 40602-0615

RECEIVED
MAR 2 2 2000
PUBLIC SERVICE
COMMISSION

RE: Big Rivers Electric Corporation
PSC Case No. 99-429

Dear Mr. Huelsmann:

In compliance with Public Service Commission regulation 807 KAR 5:058 and the Commission's Order dated December 10, 1999 in Case No. 99-429, the following documents are enclosed:

1. Petition of Big Rivers Electric Corporation for Confidential Treatment of Portions of its 1999 Integrated Resource Plan;

2. One (1) sealed and bound copy of the Integrated Resource Plan (IRP) with the confidential material highlighted;

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

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

This Integrated Resource Plan has been prepared to comply with the Commission's regulations and to serve as a guide for Big Rivers in planning its resources to meet its future system demands. The fact should be noted that Big Rivers no longer operates generating units, which means that many of the filing requirements concerning power plants are no longer applicable to Big Rivers. As a consequence, this integrated resource plan is significantly different from Big Rivers' previous integrated resource plan filings and will not be similar to the filings of the other utilities in the state.

As stated on the certificate of service on the petition for confidential treatment, the petition, with a copy of the redacted IRP attached, has been served on the parties shown on the certificate. If you have any questions regarding this filing, please do not hesitate to contact me.

Sincerely,

BIG RIVERS ELECTRIC CORPORATION

David A. Spainhoward

David A. Spainhoward
Vice President
Contract Administration and Regulatory Affairs

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

RECEIVED
MAR 22 2000
PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC CORPORATION)

CASE NO. 99-429

PETITION OF BIG RIVERS ELECTRIC CORPORATION FOR CONFIDENTIAL TREATMENT OF CERTAIN PORTIONS OF ITS 1999 INTEGRATED RESOURCE PLAN

Big Rivers Electric Corporation ("Big Rivers"), pursuant to 807 KAR 5:001(7), respectfully petitions the Kentucky Public Service Commission ("Commission") to classify and protect as confidential certain information contained in its 1999 Integrated Resource Plan ("IRP") filed with this petition on March 22, 2000. The IRP is filed pursuant to 807 KAR 5:058 to provide the Commission with information including Big Rivers' historical and projected demand, resource, and financial data, and other operating performance and system information, in addition to the facts, assumptions, and conclusions on which the plan is based and the actions that the plan proposes. 807 KAR 5:058(1)(2). In support of this petition, Big Rivers states as follows:

1. One (1) sealed copy of the IRP containing the confidential information, with that information highlighted, and ten (10) copies of the IRP with the confidential information redacted are filed with this petition. 807 KAR 5:001(7)(2)(a)(2) and 5:001(7)(2)(b). One (1) additional, unbound copy of the IRP, with the confidential information redacted, is also filed with this petition so that 807 KAR 5:058(1)(3) is satisfied.

2. As grounds for confidentiality pursuant to 807 KAR 5:001(7)(2)(a)(1), Big Rivers states that the information for which confidential treatment is requested is within the category of commercial information "generally recognized as confidential or proprietary, which if openly

disclosed would permit an unfair commercial advantage to the competitors of the entity that disclosed the records." KRS 61.878(1)(c). The information that 807 KAR 5:058 requires the IRP to contain includes highly sensitive information on matters including strategic planning, finance, resources and operations. The public disclosure of such information would, in the current and changing industry, give an unfair advantage to the competitors of Big Rivers and would adversely impact Big Rivers.

3. The public disclosure of the information designated as confidential by Big Rivers would provide its competitors with an unfair advantage by injuring the ability of Big Rivers to buy power at the most competitive prices, and by disclosing proprietary information on the operations of Big Rivers. The information designated as confidential generally comes within the following two categories:

(i) Cost Summaries and Revenue Requirements. To maintain a competitive posture in the wholesale power market and continued successful arbitrage efforts, Big Rivers' revenue requirements and cost summaries must be confidential. This information is not public. By letter dated November 13, 1998, the Commission granted confidential treatment to material in the Six-Month Arbitrage Report filed by Big Rivers on November 23, 1998.

(ii) Power Supply Cost from LEM. Big Rivers acknowledges that the cost of the power that Big Rivers purchases from LEM has been disclosed in other forms, however, Big Rivers submits that the disclosure of such information as contained and presented in the IRP could adversely impact Big Rivers. The IRP is subject to request by marketers and competitors who could, if this information were made public in the IRP, readily access this information to the detriment of Big Rivers. This information is contained in Tables IV-3 and IV-4 on page IV -10 of the IRP.

4. The treatment of the information as confidential should not hinder the Commission or the parties in the presentation and consideration of this matter.

5. If and to the extent that any of the confidential information becomes generally available to the public, whether through filings required by other agencies or otherwise, Big Rivers will notify the Commission and have its confidential status removed. 807 KAR 5:001(7)(9)(a).

WHEREFORE, Big Rivers respectfully requests the Commission to classify and protect as confidential the information filed with this petition.

Mark Willis

James M. Miller
Mark Willis
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Street, P.O. Box 727
Owensboro, KY 42302-0727
(270) 926-4000

Douglas L. Beresford
Long, Aldridge & Norman LLP
701 Pennsylvania Avenue, N.W.
Suite 600
Washington, D.C. 20004
(202) 624-1200

Counsel for Big Rivers Electric Corporation

CERTIFICATE OF SERVICE

I hereby certify that a copy of this petition and a redacted copy of the IRP were served on the following by Federal Express on this 21st day of March, 2000:

David C. Brown, Esq.
Stites & Harbison
400 West Market Street, Suite 1800
Louisville, KY 40202-3352

Counsel for Alcan Aluminum Corp.

Allison Wade, Esq.
Holland & Knight
1201 West Peachtree Street, NE,
Suite 2000
Atlanta, GA 30309-3400

Counsel for Southwire Company & NSA, Inc.

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

**Co-counsel for Southwire Company & NSA, Inc.
and Alcan Aluminum Corp.**

Elizabeth Blackford, Esq.
Assistant Attorney General
Utility and Rate Intervention Division
1024 Capital Center Drive, Suite 200
Frankfort, KY 40601

Office of the Attorney General of the Commonwealth of Kentucky

John Stapleton
Director of Energy NREPC
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

Counsel for Natural Resources and Enviromental Protection

Mark Willis
Mark Willis

1999 Integrated Resource Plan

for

Big Rivers Electric Corporation
Henderson, Kentucky
Kentucky 62

1999

99-089-4

BigRivers Electric Corporation

A Touchstone Energy™ Partner

Burns & McDonnell
SINCE 1898

1999 Integrated Resource Plan

for

Big Rivers Electric Corporation
Henderson, Kentucky
Kentucky 62

1999

99-089-4

Big Rivers Electric Corporation

A Touchstone Energy Partner

Burns & McDonnell
SINCE 1898

Burns & McDonnell
SINCE 1898

March 16, 2000

Mr. C. William Blackburn
Vice President of Power Supply
Big Rivers Electric Corporation
201 Third Street
P.O. Box 24
Henderson, KY 42419-0024

Big Rivers Electric Corporation
Integrated Resource Planning Study
Project 99-089-4 Final Report

Dear Mr. Blackburn:

We are pleased to submit this final report on the 1999 Integrated Resource Plan. This integrated resource planning study for has been prepared by Burns & McDonnell to meet the requirements of the Kentucky Public Service Commission's regulation 807 KAR 5:058 - Integrated resource planning by electric utilities and to serve as a guide for Big Rivers in planning its resources to meet its future system demands.

We appreciate the opportunity to assist Big Rivers the development of this resource plan. If there are any questions, please do not hesitate to call us.

Sincerely,

James M. Flucke

James M. Flucke, P.E.
Project Manager

Scott C. Renze

Scott C. Renze
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690
www.burnsmcd.com

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

TABLE OF CONTENTS
(CONTINUED)

LIST OF TABLES

PART I – EXECUTIVE SUMMARY

PART II – INTRODUCTION AND EXISTING SYSTEM

PART III – POWER SUPPLY SCREENING ANALYSIS

PART IV – DEMAND-SIDE MANAGEMENT SCREENING ANALYSIS

PART V – PRODUCTION COST MODELING

LIST OF TABLES
(CONTINUED)

PART VI – RISK ASSESSMENT

LIST OF FIGURES

PART I – EXECUTIVE SUMMARY

PART II – INTRODUCTION AND EXISTING SYSTEM

PART III– POWER SUPPLY SCREENING ANALYSIS

PART IV – DEMAND-SIDE MANAGEMENT SCREENING ANALYSIS

PART V – PRODUCTION COST MODELING

PART VI – RISK ASSESSMENT

* * * * *

Part I

Executive Summary

PART I
EXECUTIVE SUMMARY
(Section 5 of the Integrated Resource Planning Regulation)

This Integrated Resource Planning Study for Big Rivers Electric Corporation (Big Rivers) has been prepared by Burns & McDonnell to meet the requirements of the Kentucky Public Service Commission's regulation 807 KAR 5:058 - Integrated resource planning by electric utilities and to serve as a guide for Big Rivers in planning its resources to meet its future system demands. In order to make this report easier to review, the section number(s) of the regulation being addressed will be included in the title of each topic of this report where appropriate.

INTRODUCTION (§5 (1))

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. With the exception of two aluminum smelters served by Kenergy, Alcan and Southwire, Big Rivers provides all of the power requirements of the following three member distribution cooperatives with service territories in western Kentucky:

Member	RUS Designation
Kenergy Corp. Henderson, Kentucky	Kentucky 65
Jackson Purchase Energy Corporation Paducah, Kentucky	Kentucky 20
Meade County Rural Electric Cooperative Corporation Brandenburg, Kentucky	Kentucky 18

Green River Electric Corporation and Henderson Union Electric Cooperative merged to form the Kenergy Corp. on July 1, 1999.

The three distribution cooperatives serve primarily residential consumers, with 88,790 residential consumers in 1999 or 90.0 percent of total consumers. Big Rivers currently provides power to its members through seventy-seven rural substations as well as twenty-one dedicated metering points. Power is delivered based on tariffs that became effective in July 1998.

SIGNIFICANT CHANGES SINCE 1993 IRP (§6)

Big Rivers has undergone significant changes since the submission of its 1993 IRP to the Kentucky Public Service Commission. The change that has the biggest impact is that Big Rivers owns but no longer operates the generating facilities described in the 1993 IRP. Big Rivers now purchases a portion of the capacity and energy of these units through an arrangement with LG&E Energy Marketing, Inc. (LEM). As a part of this agreement, Big Rivers no longer provides wholesale power service to support Kenergy's retail sales to two aluminum smelters. This change significantly reduces the amount of energy sold by Big Rivers. However, Big Rivers still must provide transmission capacity to serve the electric load of the aluminum smelters.

In addition, the fact that Big Rivers no longer operates generating units means that many of the IRP filing requirements concerning power plants are no longer applicable. As a consequence, this IRP is significantly different from Big Rivers' previous IRP filings and will not be similar to the filings of the other utilities in the Commonwealth.

Big Rivers has recently received approval from the Kentucky Public Service Commission for a new rate schedule on a temporary, pilot basis. Rate Schedule 10 will be for new industrial loads of its members, or expanded loads of member's existing industrial customers, of 5 MW or more. This rate schedule will reflect market-based rates and will allow Big Rivers to minimize the impact of member's industrial load growth on the results of this study.

LOAD FORECAST (§5 (3))

The 1999 Power Requirements Study (PRS) prepared by Burns & McDonnell for Big Rivers has been provided to Big Rivers under separate cover and meets the load forecast requirements of the Rural Utilities Service (RUS) as well as the Commonwealth's integrated resource planning regulation. The complete text of the 1999 PRS for Big Rivers is included as Appendix A.

The load forecast was performed by Burns & McDonnell and provided to Big Rivers in the 1999 Power Requirements Study. The forecast load growth for Big Rivers is provided in Table I-1. The system peak demand for generation service provided by Big Rivers is projected to grow at an average annual rate of 2.4 percent during the time period from 1998 to 2013. Total energy requirements for generation service provided by Big Rivers are projected to grow at an average annual rate of 2.6 percent during the time period from 1998 to 2013. When the electric load of the two aluminum smelters are included, the system-peak demand for transmission service provided by Big Rivers is projected to grow at an average annual rate of 1.7% and the corresponding energy is projected to grow at an average annual rate of 1.8% from 1998 to 2013.

Table I-1

Big Rivers Demand and Energy Requirements and Resources
Big Rivers Electric Corporation

Year	System Peak Demand (MW) [1]	Expected Load Reduction From Customer Generation (MW)	Peak Demand Less Customer Generation (MW)	Total Energy Requirements for Generation Service Provided by Big Rivers (MWh/Yr) [2]	LEM Contract Maximum Capacity (MW)	LEM Contract Maximum Energy (MWh/Yr)	SEPA Contract Maximum Capacity (MW)	SEPA Contract Maximum Energy (MWh/Yr)	Capacity Surplus/Deficit (MW)
1999	683	0	683	3,686,368	572	5,112,750	178	267,000	67
2000	717	0	717	3,913,183	572	5,112,750	178	267,000	33
2001	735	62	673	4,008,143	597	5,327,285	178	267,000	102
2002	751	62	689	4,090,662	597	5,327,285	178	267,000	86
2003	767	62	705	4,161,735	597	5,327,285	178	267,000	70
2004	782	62	720	4,225,005	597	5,327,285	178	267,000	55
2005	797	62	735	4,294,253	597	5,327,285	178	267,000	40
2006	814	62	752	4,374,657	597	5,327,285	178	267,000	23
2007	827	62	765	4,432,741	597	5,327,285	178	267,000	10
2008	843	62	781	4,503,066	597	5,327,285	178	267,000	-6
2009	862	62	800	4,600,745	597	5,327,285	178	267,000	-25
2010	893	62	831	4,816,713	597	5,327,285	178	267,000	-56
2011	910	62	848	4,889,892	717	6,321,741	178	267,000	47
2012	927	62	865	4,965,803	800	7,008,000	178	267,000	113
2013	949	62	887	5,099,026	800	7,008,000	178	267,000	91

[1] System peak demand is the sum of non-rural demand net of smelters plus the rural system demand and includes losses.
[2] Forecasted losses for the period 1999 - 2013 were based on the formula (1 - 0.0178) multiplied by the forecasted generation sales. This includes all sales except those to the smelters.

POWER SUPPLY RESOURCES (§5 (1))

As shown in Table I-1, Big Rivers will be able to meet the majority of its demand and energy requirements through the Southeastern Power Administration (SEPA) and LEM contracts. For the next few years the requirements not met by the SEPA allotment will be supplied by the capacity and energy from the LEM agreement. Big Rivers also has access to the wholesale power markets to buy and sell power as needed subject to market availability.

Figure I-1 shows the loads and resources of Big Rivers. The graph indicates that the system will be in need of capacity beginning in the year 2004 with the projected load growth. Big Rivers' purchases from SEPA and LEM are firm contracts and the LEM contract includes liquidated damages for non-delivery (LD Firm). Therefore Big Rivers has no need for a reserve margin as is the case with generating utilities. As shown in the graph the SEPA and LEM contracts will provide capacity in excess of the projected demand until the year 2004.

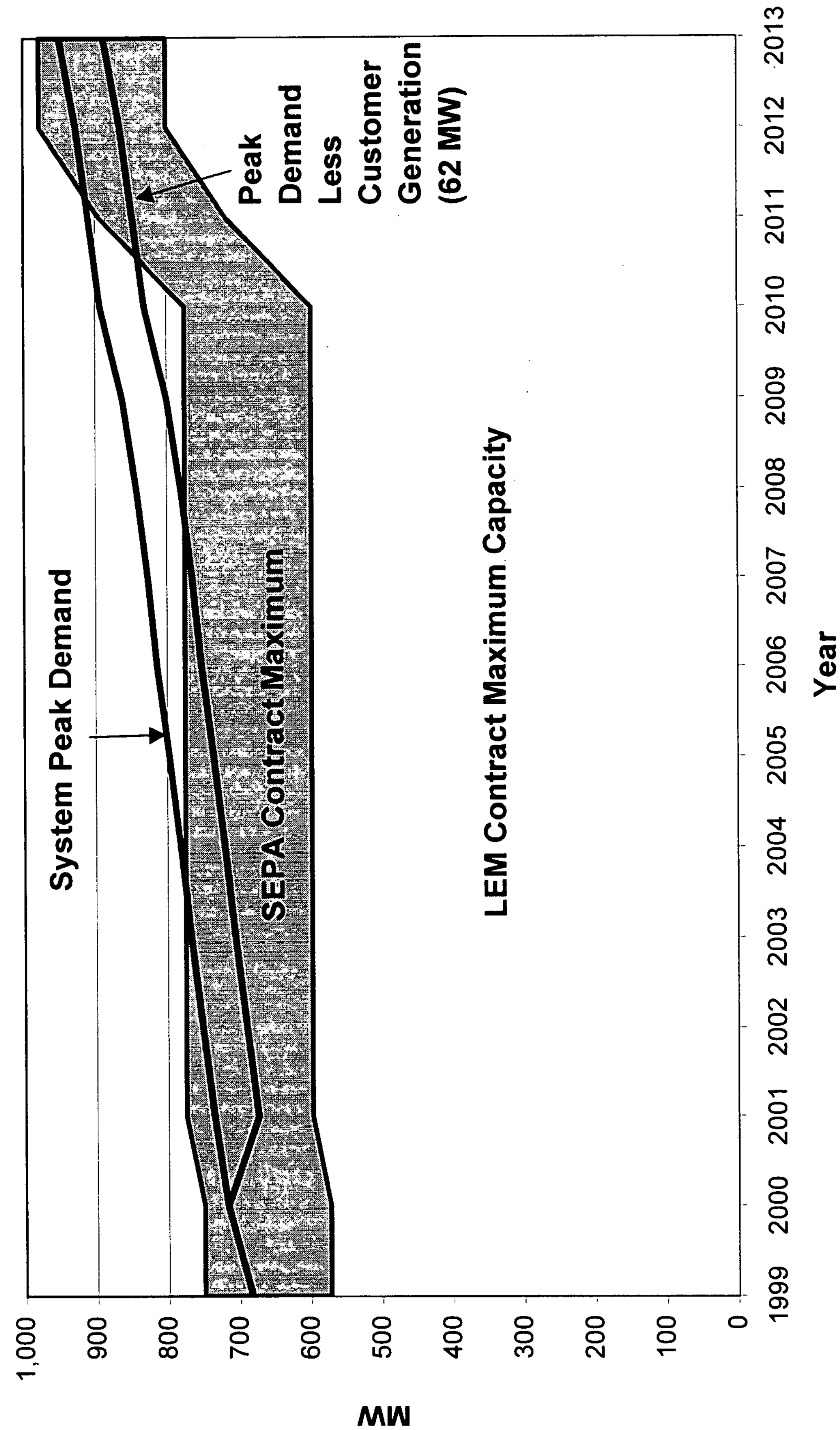
When 62 megawatts (MW) of generation is installed in the year 2001 by a customer of Kenergy, the system will not become capacity deficient until the year 2008 with the projected load growth. The increases in the capacity from the LEM contract beginning in 2011 return the Big Rivers system to a capacity surplus position.

PLANNED RESOURCES (§5 (4))

One of the end-users of energy from Kenergy is proceeding with plans to install approximately 62 MW of power generation in the spring of 2001. This generation addition will likely be operated by the end-user and backup power will be arranged by Big Rivers. Backup power will be provided from sources other than the LEM and SEPA contracts, with transmission service provided by Big Rivers. Therefore, this generation addition is effectively a 62 MW demand reduction from the perspective of Big Rivers' power supply obligations. The demand reduction could potentially reduce the energy requirement of Big Rivers by nearly 500,000 MWh based on Kenergy's customer's current 92 percent load factor. Big Rivers has signed a term sheet with its member cooperative, Kenergy, and Kenergy's customer and is in the process of drafting a contract to formalize the power supply arrangement that will exist between Big Rivers, Kenergy, and Kenergy's customer after the installation of the generation.

Big Rivers currently has no formal plans for the addition of power generation resources or new power supply contracts due to the expected installation of 62 MW of end-user generation.

Figure I-1
Big Rivers Demand and Energy Requirements and Resources
Big Rivers Electric Corporation



VOLUNTARY INDUSTRIAL CURTAILMENT

During the summer of 1999, Big Rivers worked with its members and their larger industrial customers to reduce load during times of peak demand. This program was well received by the members' customers and was mutually beneficial for Big Rivers, the member cooperatives, and their retail customers through the sharing of cost savings. Table I-2 shows the actual results of voluntary curtailment for July 30, 1999 from hour-ending 2 p.m. through hour-ending 7 p.m. Load reduction ranged from 17 MW to a high of 28 MW and the voluntary curtailment involved four industrial customers of Big Rivers' members.

Table I-2
1999 Voluntary Industrial Curtailment Results

Hour	Load Actual (MW)	Load Reduction (MW)	Load Resultant (MW)
14 (2 p.m.)	644	16	660
15	645	22	667
16	646	24	670
17	644	27	671
18	639	27	666
19	629	22	651

Big Rivers is expecting to expand the use of the program and has filed a Voluntary Curtailment Rider with the Kentucky Public Service Commission. The economics of the continued use of this program are evaluated later in this report.

POWER SUPPLY SCREENING RESULTS

Several sizes of each technology were selected to compare the operating costs at various capacity factors to screen the more applicable units for further review. The energy requirements from new capacity reviewed for Big Rivers are expected to be in the peaking and intermediate range based on the analysis of Big Rivers' load profile and LEM contract. The capacity factors for these types of resources are traditionally below 40-45 percent.

Based on the projected loads and resources available to Big Rivers and the relative capacities and costs of the options reviewed, Burns & McDonnell selected the following power supply options to move into more detailed analysis:

- 45 MW LM6000 simple-cycle combustion turbine
- 53 MW LM6000 combined-cycle combustion turbine
- Combined-Cycle Unit Purchases
- Peaking Power Purchases
- Voluntary Commercial/Industrial Load Management Program

DEMAND-SIDE MANAGEMENT SCREENING RESULTS

As part of this Integrated Resource Plan, Burns & McDonnell recommends that Big Rivers should study the implementation of a combined commercial/industrial DSM plan similar to the plan previously described in the Voluntary Industrial Curtailment section. The largest portion of this plan should target the members' industrial customers with large coincident demand and should provide an incentive for participation. This incentive can be either an interruptible rate, a shared savings payment or the market-based tariff for curtailing demand at times when the utility is facing extraordinary constraints or unusually high cost for additional capacity. The approval of Rate Schedule 10 by the Kentucky Public Service Commission is a solid first step in the implementation of this recommendation.

PRODUCTION COST MODELING (§5 (2))

Burns & McDonnell developed a spreadsheet model to simulate the dispatch of Big Rivers' power supply resources for the years 1999-2013. The model dispatched the available resources on an hourly basis taking into account both hourly, monthly and annual contract maximums and minimums and the contract prices and spot market price estimates. The output of the model contained the energy dispatch and costs associated with meeting the hourly requirements of Big Rivers. The model also utilized the daily electricity spot market index prices for the last twelve months to determine the potential for non-member electricity sales and revenues in the future. Because of the firm nature of Big Rivers' purchases and the lack of generating capacity, the model does not need to include the forced outage rates, heat rates, fuel and operation and maintenance costs that are utilized by typical production cost models.

Both existing and potential future resources were input to the model in a series of cases to determine the most cost-effective method of meeting future power supply needs. The cases were evaluated with and without the sales of surplus power. Sales of surplus energy and purchases of energy to meet load requirements were made at the projected spot market prices determined from the actual daily spot market prices of the last twelve months. The actual daily prices of the last twelve months were annually escalated by the projected spot market price escalation rates included in the Department of Energy's Annual Energy Outlook 2000 and included in Appendix F. Capacity deficiencies were assumed to be met through the purchase of peaking capacity in all cases.

Based on the results of the screening analyses described in Parts III and IV, five power supply options were considered in the production cost modeling. These options included generation, purchases, and demand-side management options. All cases were designed to meet the demand requirements of Big Rivers and modeled with and without the projected non-member sales of surplus capacity and energy.

Key assumptions and judgments that were used in the analyses include:

- Load forecast assumptions described in Appendix A
- Operation and maintenance cost escalation rate and inflation rate – 3.5%
- Natural gas escalation rate – 1.5%
- Long-term interest rate and discount rate– 6.5%
- Spot market price forecast based on 1999 spot market prices and the Department of Energy's price forecast

The spot market price forecast and natural gas price forecast were seen to have the largest impact on the plan and therefore were further analyzed in Part VI - Risk Assessment.

PRODUCTION COST MODELING RESULTS

The annual cash expenditures from the production cost modeling are included in Tables I-3 and I-4. The difference in the tables is the assumption on the sale of surplus capacity and energy to non-members. Due to some of the options installing more capacity than can be used in the study horizon, it is assumed that capacity sales of the surplus will be made to ECAR area utilities or power marketers. These sales were assumed to be made for $3.50/kW-month in 1999 increasing to $4.90/kW-month in 2013 with an annual increase of $0.10/kW-month. These prices are reflective of capacity market sales prices in the region.

Non-member sales of surplus energy were made at the projected spot market prices determined from the actual daily spot market prices of the last twelve months. The actual daily prices of the last twelve months were annually escalated by the projected spot market price escalation rates included in the Department of Energy's Annual Energy Outlook 2000 and included in Appendix F. The spot market sales reflect a best-case scenario with all available energy being sold at the spot market price.

Tables I-3 and I-4 show the potential economic benefit of the commercial/industrial load management program (Case 5). In the scenario without non-member sales, Case 5 is the lowest cost resource option over the 15-year period as a result of the load reductions and avoided payments for peaking capacity purchases in some years.

The scenario with non-member sales reflects the potential for off-system sales by Big Rivers. The sale of surplus energy from the LEM contract represents the largest portion of revenues from sales to the spot market but the installation of generating units in Cases 1 and 2 and the purchase of combined cycle unit capacity in Case 3 provide a significant source of sales. Case 2 with a 53 MW combined cycle unit provides the greatest amount of off-system sales from the resource additions analyzed and the greatest overall revenue for the five cases. The off-system sales scenario presents the potential for revenue generation from the addition of generating resources.

The generation options and purchase of combined cycle unit capacity and energy (Case 3) are not cost effective in meeting Big Rivers native load when compared to the load reduction (Case 5), spot market purchase (Case 0), and peaking purchase options (Case 4). When non-member sales of surplus capacity and energy are considered, the combined cycle option (Case 2) is the most favorable. Cases 2, 3, and 4 were evaluated with capacity being added in both the year 2002 to take advantage of potential spot market sales and in the year 2009 to meet some of the capacity requirements of Big Rivers. Detailed tables of energy sources and costs for each case are included in Appendix D.

The installation of 62 MW of generation by Kenergy's customer has a significant impact on the results of this analysis. If the unit is not installed as expected, the Big Rivers system is projected to become capacity deficient in 2004. In this event Big Rivers must begin planning for its next capacity resource. The impact of this scenario is considered in the risk assessment section of this report along with the impact of higher than expected natural gas prices and lower than expected spot market energy prices. The relative net present value of costs for the risk assessment scenarios are shown graphically in Figures I-2 and I-3.

Table I-3

COST SUMMARY TABLE FOR ALL CASES WITHOUT SALES OF SURPLUS CAPACITY AND ENERGY

Big Rivers Electric Corporation

Year	Case 0	Case 1		Case 2		Case 3		Case 4	Case 5:
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

Table I-4

COST SUMMARY TABLE FOR ALL CASES WITH SALES OF SURPLUS CAPACITY AND ENERGY

Big Rivers Electric Corporation

Year	Case 0	Case 1		Case 2		Case 3		Case 4	Case 5:
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

The projected revenues reflected in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues reflected in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Figure I-2
Comparison of Net Present Value of Total Costs
Without Sales of Available Surplus

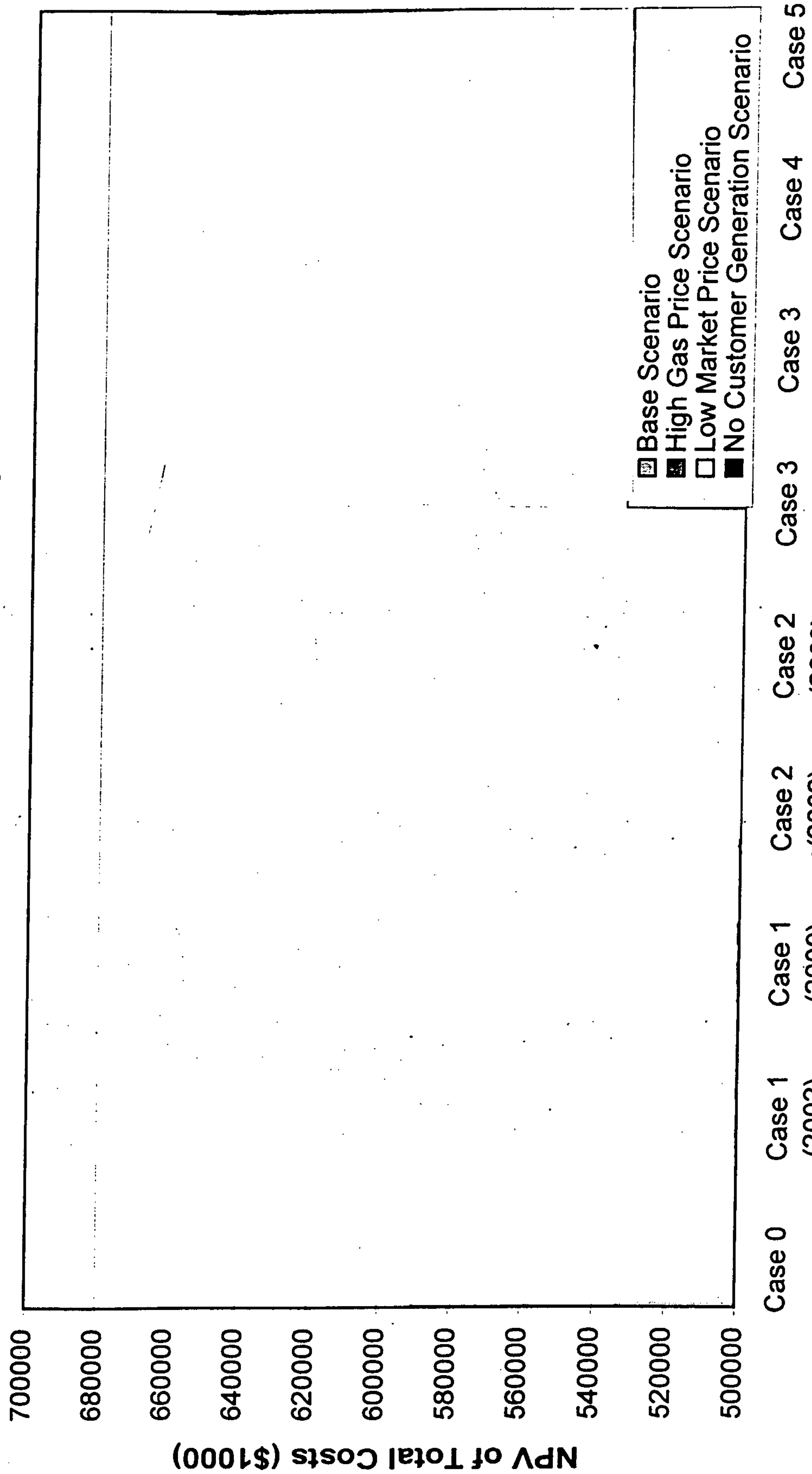
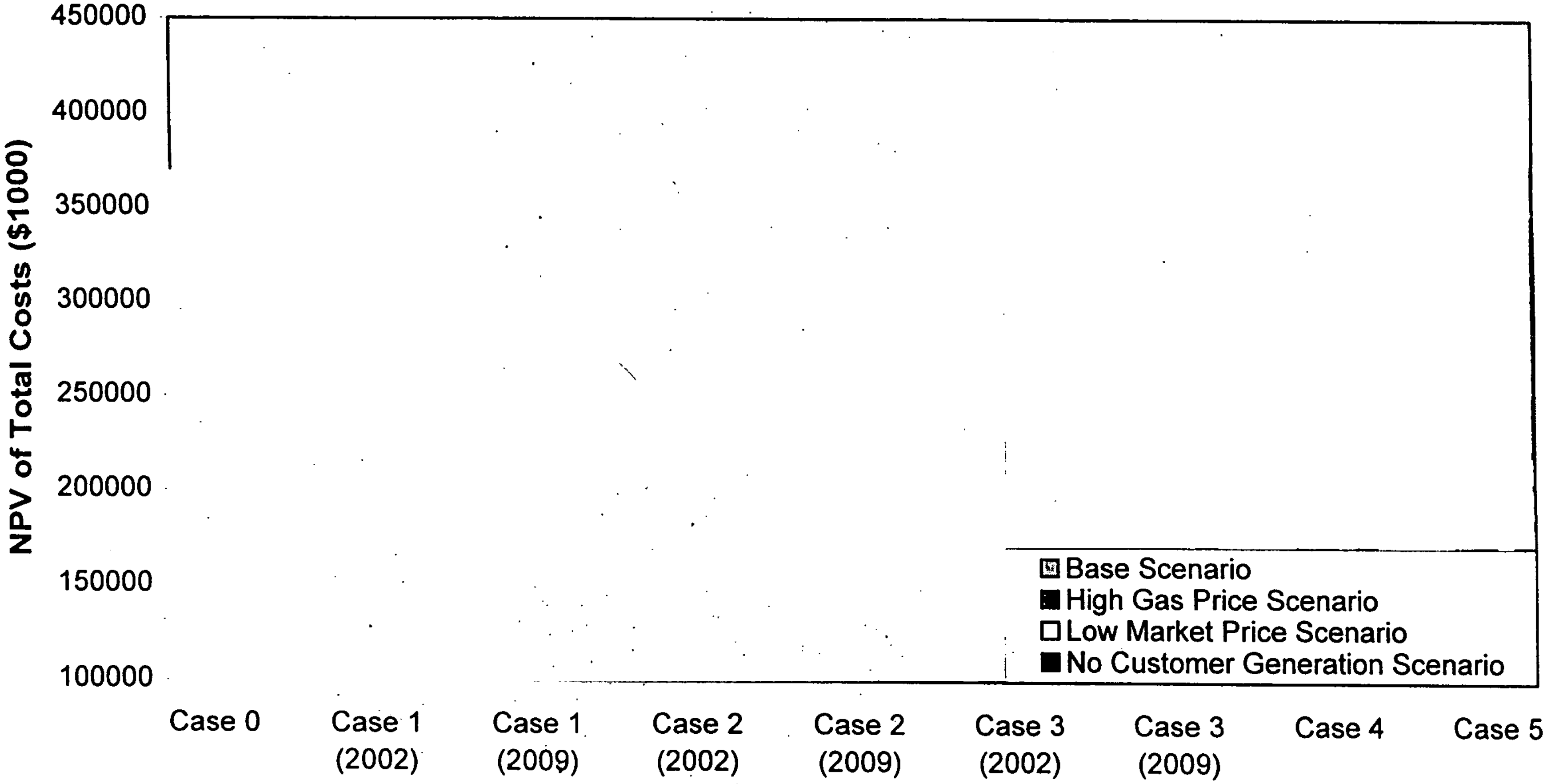


Figure I-3
Comparison of Net Present Value of Total Costs
With Sales of Available Surplus



The projected revenues reflected in this chart are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to proces closer to historical levels. The revenues reflected in this chart reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

CONCLUSIONS

Based on the results of the IRP study, Burns & McDonnell offers the following conclusions:

1. Electric load growth on Big River's system is expected to slow in the next fifteen years compared to the past five years. Not including the aluminum smelter load, average annual energy growth is projected at 2.6% over the next fifteen years (versus historical growth of 6.8% since 1994) and average annual growth in peak demand is projected at 2.4% percent (versus historical growth of 6.7% since 1994). Average annual energy growth is projected to be 1.8% and average annual growth in peak demand is projected at 1.7% percent when including the aluminum smelter loads for transmission and distribution purposes. Although this level of growth is less than recent historical growth rates, it is similar to long-term historical growth rates for Big Rivers. The recent historical growth rates are higher in the PRS because of abnormal demand and energy requirements in 1994.

2. The installation of 62 MW of Kenergy's customer's generation has the most significant impact on future operating conditions for Big Rivers. If the unit is installed as expected, the Big Rivers system will likely not become capacity deficient until the year 2008. Big Rivers will become capacity deficient in 2004 if the unit is not installed and Kenergy's customer continues to purchase all of its power requirements.

   Another uncertainty on Big Rivers' future operating conditions is the potential modification or termination of Big Rivers' contract with the Southeastern Power Administration. Big Rivers depends on the SEPA contract to meet its peak demand throughout the study period. At the current time there is no pending legislation which would alter the SEPA contract. However, there has been discussion by Congress of changing the current mode of operation of the Power Marketing Administrations.

3. The risk analysis quantified the effects of several key uncertainties facing Big Rivers. The no customer generation scenario quantified the impacts of Big Rivers depending on Kenergy's customer's generation to meet load requirements. The low market energy cost scenario quantified the potential risks and rewards of relying on the short-term spot market for energy purchases versus relying on a specific group of resources for energy. The high gas price scenario quantified the impact of gas price uncertainty when installing gas-fired resources.

   In general, the no customer generation scenario has the most significant affect on the cases analyzed because of the significant increase in demand and energy requirements beginning in the year 2001.

However, even this impact does not change the overall recommendations resulting from the base case analysis.

THREE-YEAR PLAN (§5 (5) and §5 (6))

1. Proceed with the development of a contract to formalize the power supply arrangement and determine the installation schedule for 62 MW of Kenergy's customer's generation. If the unit is installed as planned, Big Rivers will have the opportunity to delay the decision on its next resource addition. The addition of 62 MW of Kenergy's customer's generation will postpone when Big Rivers is projected to become capacity deficient from 2004 to 2009. It is Burns & McDonnell's understanding that this unit is expected by Big Rivers to be operational in the spring of 2001.

2. If Kenergy's customer's generation is not installed Big Rivers will then need to immediately begin the decision making process on the acquisition of its next resource to meet peak demand in the years 2004-2011. Without the customer generation Big Rivers' capacity deficiency is projected to peak in 2010 at 118 MW before increases in the capacity of the LEM contract take effect in 2011 and 2012 and eliminate the capacity deficiency. From the results of the customer generation risk assessment it would appear that after the commercial/industrial load management program, combustion turbines and peaking power purchases reflect the most economical method to meet the capacity deficiency and minimize the potential financial risks associated with spot market purchases. This evaluation is based on the annual revenue requirements and 15-year net present values of total revenue requirements shown in Figures I-2 and I-3.

3. Burns & McDonnell recommends that Big Rivers continue its current evaluation of the implementation of a combined commercial/industrial load management plan. The largest portion of this plan should target the member's industrial customers with high coincident demand and should provide an incentive for participation. This incentive can be either an interruptible rate, a shared savings payment or operation under the market-based rate schedule. The plan should be designed to curtail demand at times when the utility is facing extraordinary constraints or unusually high cost for additional capacity. The identification of industrial customers suitable for this program will be an ongoing process that should build upon the current foundation of the program.

   This type of program has proven to not only lower peak demand and energy requirements providing for non-member sales during times of high spot market prices but also builds customer satisfaction.

By taking a proactive role in keeping its members and their customers satisfied, Big Rivers can help ensure its ongoing success.

4. Big Rivers should encourage the use of distributed generation among its members to lower peak demands and energy requirements and provide Big Rivers with greater flexibility in its power supply operations. The benefits of distributed generation for Big Rivers would be similar to the impacts of the 62 MW of Kenergy's customer's generation evaluated in this study.

   Distributed generation utilizing reciprocating engines, small combustion turbines, and potentially fuel cells, microturbines, and renewable resources is becoming more and more popular for the benefits they can provide both to the customer and the host utility. The analysis of the potential benefits of distributed generation additions is very site specific and must be performed on a case-by-case basis.

5. Big Rivers should maintain an ongoing dialogue with other potential power suppliers regarding low cost energy and capacity sources. Locking in low-cost capacity and energy would further mitigate the risks associated with spot market purchases and the limitations of the SEPA contract in meeting peak demands during the summer. Discussions should also be entered into within the next three years for power to meet requirements in the 2004 to 2011 time frame if necessary.

6. Big Rivers should continue to monitor the progress of state and federal legislation to determine the potential impacts on the operations of the Big Rivers system.

During the course of this study, Burns & McDonnell prepared certain estimates and projections. The estimates and projections prepared by Burns & McDonnell relating to interest rates and other financial analysis parameters, capital cost estimates, resource cost proposals, operation and maintenance costs, and operating results are based on our experience, qualifications and judgment as a professional consultant. Burns & McDonnell has no control over the underlying assumptions for these projections including but not limited to economic conditions, government regulations and laws (including their interpretation), competitive bidding or market conditions, and other factors affecting such estimates or projections. Therefore, Burns & McDonnell does not guarantee that actual cost projections will not vary from the estimates and projections prepared in this report by Burns & McDonnell.

*****

Part II

Introduction and Existing System

PART II
INTRODUCTION AND EXISTING SYSTEM

This Integrated Resource Planning Study for Big Rivers Electric Corporation (Big Rivers) has been prepared by Burns & McDonnell to meet the requirements of the Kentucky Public Service Commission's regulation 807 KAR 5:058 - Integrated resource planning by electric utilities and to serve as a guide for Big Rivers in planning its resources to meet its future system demands. In order to make this report easier to review, the section number(s) of the regulation being addressed will be included in the title of each topic of this report where appropriate. The fact that Big Rivers no longer operates generating units means that many of the IRP filing requirements concerning power plants are no longer applicable. As a consequence, this IRP is significantly different from Big Rivers' previous IRP filings and will not be similar to the filings of the other utilities in the Commonwealth.

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. With the exception of two aluminum smelters served by Kenergy, Alcan and Southwire, Big Rivers provides all of the power requirements of the following three member distribution cooperatives with service territories in western Kentucky:

Member	RUS Designation
Kenergy Corp. Henderson, Kentucky	Kentucky 65
Jackson Purchase Energy Corporation Paducah, Kentucky	Kentucky 20
Meade County Rural Electric Cooperative Corporation Brandenburg, Kentucky	Kentucky 18

Green River Electric Corporation and Henderson Union Electric Cooperative merged to form the Kenergy Corp. on July 1, 1999.

The three distribution cooperatives serve primarily residential consumers, with 88,790 residential consumers in 1999 or 90.0 percent of total consumers. Big Rivers currently provides power to its members through seventy-seven rural substations as well as twenty dedicated metering points. Power is delivered based on tariffs that became effective in July 1998.

SIGNIFICANT CHANGES SINCE 1993 IRP (§6)

Big Rivers has undergone significant changes since the submission of its 1993 IRP to the Kentucky Public Service Commission. The change that has the biggest impact is that Big Rivers owns but no longer operates the generating facilities described in the 1993 IRP. Big Rivers now purchases a portion of the capacity and energy of these units through an arrangement with LG&E Energy Marketing, Inc. (LEM). As a part of this agreement, Big Rivers no longer provides wholesale power service to support Kenergy's retail sales to two aluminum smelters. This change significantly reduces the amount of energy sold by Big Rivers. However, Big Rivers still must provide transmission capacity to serve the electric load of the aluminum smelters.

Big Rivers has recently received approval from the Kentucky Public Service Commission for a new rate schedule on a temporary, pilot basis. Rate Schedule 10 will be for new industrial loads of its members, or expanded loads of member's existing industrial customers, of 5 MW or more. This rate schedule will reflect market-based rates and allow Big Rivers to minimize the impact of member's industrial load growth on the results of this study.

The load forecast has been updated from the 1993 IRP and the comparison of the forecasts is included in Table II-1. The increase in demand and energy requirements for Big Rivers reflects the expansion of the paper mills in the service territory and the addition of poultry farming and processing loads.

LOAD FORECAST (§7)

The 1999 Power Requirements Study (PRS) prepared by Burns & McDonnell for Big Rivers has been provided to Big Rivers under separate cover and meets the load forecast requirements of the Rural Utilities Service (RUS) as well as the Commonwealth's integrated resource planning regulation. The complete text of the 1999 PRS for Big Rivers is included as Appendix A.

The load forecast was performed by Burns & McDonnell and provided to Big Rivers in the 1999 Power Requirements Study. The forecast load growth for Big Rivers is summarized in Table II-2. The system peak demand for generation service provided by Big Rivers occurs in the summer and is projected to grow at an average annual rate of 2.4% during the time period from 1998 to 2013. Total energy requirements for generation service provided by Big Rivers are projected to grow at an average annual rate of 2.6% during the time period from 1998 to 2013. When the electric load of the two aluminum smelters are included, the system-peak demand for transmission service provided by Big Rivers is projected to grow at an average annual rate of 1.7% and the corresponding energy is projected to grow at an average annual rate of 1.8% from 1998 to 2013.

Table II-1

TOTAL SYSTEM ENERGY REQUIREMENTS, PEAK DEMAND AND LOAD FACTOR
Big Rivers Electric Corporation

Year	Non-Smelter Total System Demand [1] (kW)	Total System Demand [1] (kW)	Total System Demand 1993 IRP [2] (kW)	Non-Smelter Total System Energy Requirements (MWh)	Total System Energy Requirements (MWh)	Total System Energy Requirements 1993 IRP [3] (MWh)
1994	509,546	1,213,454	1,163,000	2,660,778	7,454,549	8,201,000
1995	552,813	1,143,967	1,173,000	2,958,176	7,961,752	8,362,000
1996	565,744	1,159,973	1,193,000	3,012,342	7,882,784	8,468,000
1997	597,653	1,196,455	1,226,000	3,199,829	8,071,289	8,607,000
1998	661,374	1,266,443	1,185,000	3,464,995	8,438,991	8,358,000
1999	682,628	1,368,628	1,195,000	3,686,368	9,575,331	8,407,000
2000	716,785	1,402,785	1,204,000	3,913,183	9,798,109	8,456,000
2001	735,408	1,421,408	1,215,000	4,008,143	9,891,378	8,507,000
2002	751,267	1,437,267	1,226,000	4,090,662	9,972,428	8,565,000
2003	767,132	1,453,132	1,237,000	4,161,735	10,042,236	8,619,000
2004	781,527	1,467,527	1,248,000	4,225,005	10,104,380	8,674,000
2005	797,063	1,483,063	1,259,000	4,294,253	10,172,395	8,731,000
2006	813,929	1,499,929	1,271,000	4,374,657	10,251,368	8,789,000
2007	826,954	1,512,954	1,282,000	4,432,741	10,308,418	8,848,000
2008	842,733	1,528,733		4,503,066	10,377,491	
2009	862,305	1,548,305		4,600,745	10,473,432	
2010	893,135	1,579,135		4,816,713	10,685,555	
2011	909,557	1,595,557		4,889,892	10,757,432	
2012	926,593	1,612,593		4,965,803	10,831,992	
2013	949,437	1,635,437		5,099,026	10,962,843	
2014	965,821	1,651,821		5,172,041	11,034,559	
2015	984,279	1,670,279		5,253,381	11,114,451	
2016	1,000,982	1,686,982		5,328,089	11,187,829	
2017	1,018,648	1,704,648		5,407,075	11,265,409	
2018	1,042,618	1,728,618		5,545,580	11,401,449	

[1] System peak demand equals rural system coincident peak demand plus non-rural non-coincident peak demand.
[2] From Table 7.(5)(b) of 1993 Integrated Resource Plan, August 1993
[3] From Table 7.(5)(a)-1 of 1993 Integrated Resource Plan, August 1993

Table II-2

Big Rivers Demand and Energy Requirements and Resources
Big Rivers Electric Corporation

Year	System Peak Demand (MW) [1]	Expected Load Reduction From Customer Generation (MW)	Peak Demand Less Customer Generation (MW)	Total Energy Requirements for Generation Service Provided by Big Rivers (MWh/Yr) [2]	LEM Contract Maximum Capacity (MW)	LEM Contract Maximum Energy (MWh/Yr)	SEPA Contract Maximum Capacity (MW)	SEPA Contract Maximum Energy (MWh/Yr)	Capacity Surplus/Deficit (MW)
1999	683	0	683	3,686,368	572	5,112,750	178	267,000	67
2000	717	0	717	3,913,183	572	5,112,750	178	267,000	33
2001	735	62	673	4,008,143	597	5,327,285	178	267,000	102
2002	751	62	689	4,090,662	597	5,327,285	178	267,000	86
2003	767	62	705	4,161,735	597	5,327,285	178	267,000	70
2004	782	62	720	4,225,005	597	5,327,285	178	267,000	55
2005	797	62	735	4,294,253	597	5,327,285	178	267,000	40
2006	814	62	752	4,374,657	597	5,327,285	178	267,000	23
2007	827	62	765	4,432,741	597	5,327,285	178	267,000	10
2008	843	62	781	4,503,066	597	5,327,285	178	267,000	-6
2009	862	62	800	4,600,745	597	5,327,285	178	267,000	-25
2010	893	62	831	4,816,713	597	5,327,285	178	267,000	-56
2011	910	62	848	4,889,892	717	6,321,741	178	267,000	47
2012	927	62	865	4,965,803	800	7,008,000	178	267,000	113
2013	949	62	887	5,099,026	800	7,008,000	178	267,000	91

[1] System peak demand is the sum of non-rural demand net of smelters plus the rural system demand and includes losses.

[2] Forecasted losses for the period 1999 - 2013 were based on the formula (1 - 0.0178) multiplied by the forecasted generation sales. This includes all sales except those to the smelters.

In addition to the native-load obligations of the utility, there are certain wholesale power sales contracts that have been entered into which obligate Big Rivers to provide capacity and energy for a period of time. These contracts include sales to Hoosier Energy Rural Electric Cooperative (Hoosier), Oglethorpe Power Corporation (Oglethorpe), and Henderson Municipal Power & Light (HMPL). All of the requirements for these contracts must be purchased from LEM according to section 4.1 (b) of the LEM contract. LEM is required to serve the capacity and energy requirements associated with these contracts. These capacity and energy requirements are not included in the load forecast or the integrated resource planning study as they were in the 1993 IRP. All three of these contracts will expire in the next three years.

POWER SUPPLY RESOURCES (§8 (3) (C))

As shown in Table II-2, Big Rivers will be able to meet the majority of its demand and energy requirements through the SEPA and LEM contracts. For the next few years the requirements not met by the SEPA allotment will be supplied by the capacity and energy from the LEM agreement. Big Rivers also has access to the wholesale power markets to buy and sell power as needed subject to market availability.

Figure II-1 shows the loads and resources of Big Rivers. The graph indicates that the system will be in need of capacity beginning in the year 2004 with the projected load growth. Big Rivers' purchases from SEPA and LEM are firm contracts and the LEM contract includes liquidated damages for non-delivery (LD Firm). Therefore Big Rivers has no need for a reserve margin as is the case with generating utilities. As shown in Figure II-1 the SEPA and LEM contracts will provide capacity in excess of the projected demand until the year 2004.

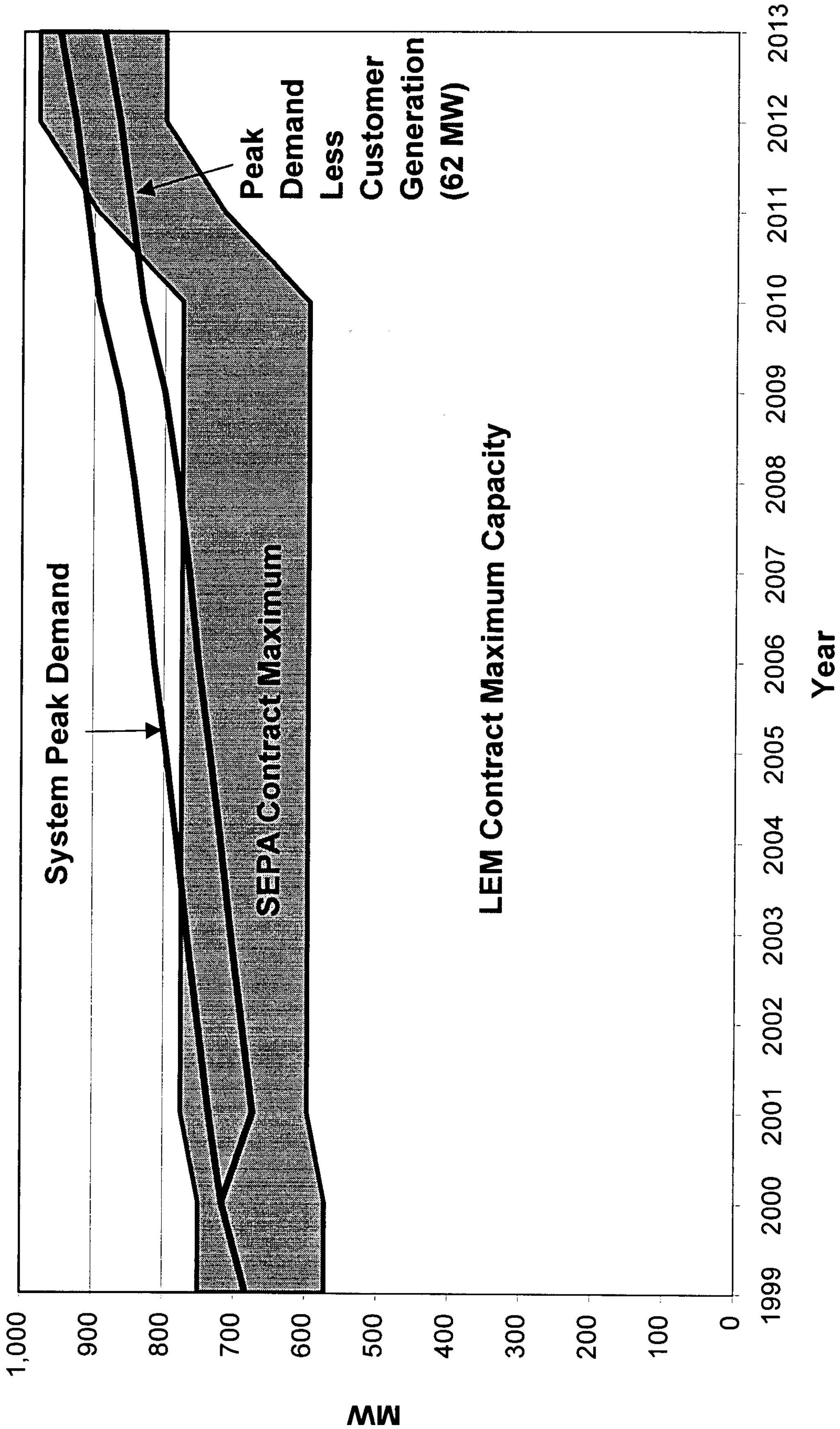
When 62 MW of Kenergy's customer's generation is installed in the year 2001, the system will not become capacity deficient until the year 2008 with the projected load growth. The increases in the capacity from the LEM contract beginning in 2011 return the Big Rivers system to a capacity surplus position.

The following paragraphs provide a general description of the purchase power contracts that currently make up Big Rivers' power supply resources.

LG&E Energy Marketing Inc.

Big Rivers Electric Corporation has a 25-year base power contract with LG&E Energy Marketing Inc. that will be in effect through 2023. This contract specifies the minimum and maximum hourly and annual capacity and energy amounts at substantially fixed rates. The pertinent capacity and energy contract

Figure II-1
Big Rivers Demand and Energy Requirements and Resources
Big Rivers Electric Corporation



details may be seen on Table II-2. As seen on the table, the amount of capacity available to Big Rivers from the LEM contract remains constant at 597 MW from 2001 to 2010 and then increases to 717 MW in 2011 and to 800 MW in 2012.

Southeastern Power Administration

Big Rivers has a firm power contract with the Southeastern Power Administration. The SEPA contract allows Big Rivers to take fixed capacity and energy allocations based on a monthly schedule. The contract runs through June 2017. The pertinent capacity and energy contract details may be seen on Table II-2.

Big Rivers has 178 MW of available capacity from the SEPA contract throughout the study period. The SEPA contract limits the monthly energy taken by Big Rivers to 42,720 MWh and imposes a minimum energy take of 10,680 MWh per month. The monthly limitation could potentially expose Big Rivers to energy purchases from the spot market or other short-term sources of power for a limited time during the summer peak months.

PLANNED RESOURCES (§8 (3) (d))

One of the end-users of energy from Kenergy is proceeding with its plans to install approximately 62 MW of power generation in the spring of 2001. This generation addition will likely be operated by the end-user and backup power will be arranged by Big Rivers. Backup power will be provided from sources other than the LEM and SEPA contracts, with transmission service provided by Big Rivers. Therefore, this generation addition is effectively a 62 MW demand reduction from the perspective of Big Rivers' power supply obligations. The demand reduction could potentially reduce the energy requirement of Big Rivers by nearly 500,000 MWh based on Kenergy's customer's current 92 percent load factor. Big Rivers has signed a term sheet with its member, Kenergy, and Kenergy's customer and is in the process of drafting a contract to formalize the power supply arrangement that will exist between Big Rivers, Kenergy, and Kenergy's customer after the installation of the generation.

Big Rivers currently has no formal plans for the addition of power generation resources or new power supply contracts due to the expected installation of 62 MW of end-user generation.

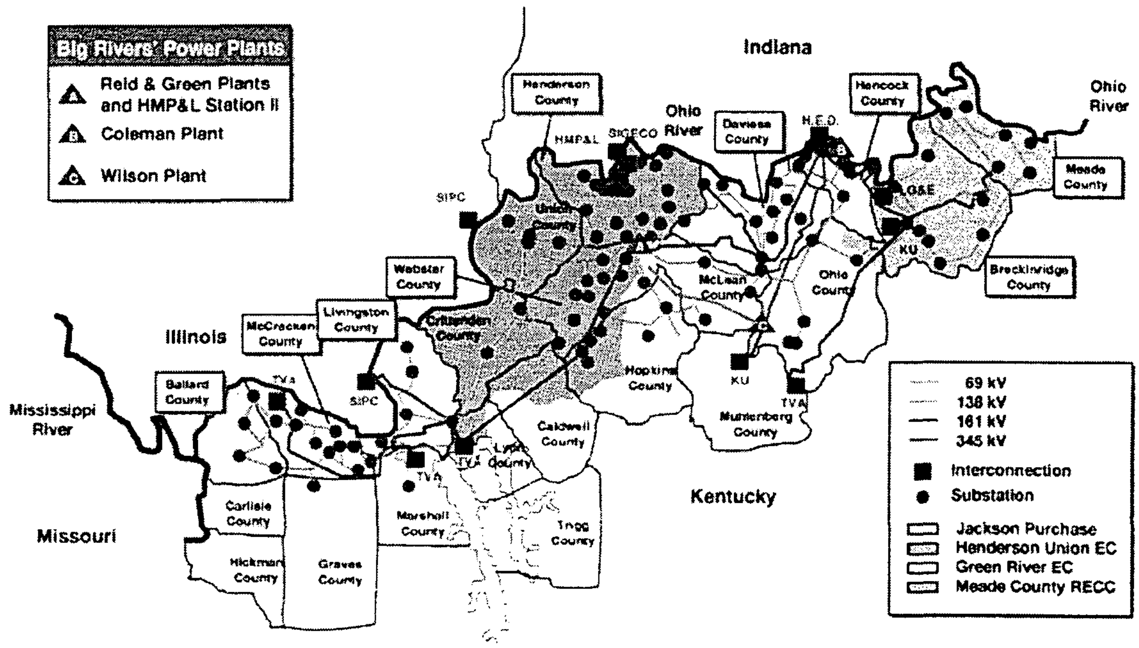
TRANSMISSION RESOURCES (§8 (3) (a))

Big Rivers owns an extensive transmission system for the delivery of power to the distribution systems of the member cooperatives. The system is interconnected with Louisville Gas & Electric, the Tennessee

Valley Authority, Kentucky Utilities, Southern Illinois Power Cooperative, Hoosier Energy, Henderson Municipal Power & Light, and Southern Indiana Gas and Electric Company. Based on the transfer capacity of the electrical interconnections and the forecasted load growth it is expected that the local interconnections can import the total needs of the Big Rivers system without major modification over the study period. A map of the Big Rivers transmission system is shown in Figure II-2.

Figure II-2

Big Rivers Transmission System Map (§8 (3) (a))



ECAR REGION (§8 (5) (g))

The Big Rivers system is located within the East Central Area Reliability Council (ECAR) region. The ECAR region has numerous energy resources located within it. These include a large amount of coal-fired and several nuclear base load power plants throughout the region. The region will be capacity deficient in 2004, according to the North American Electric Reliability Council's Electricity Supply and Demand database of projected generating capacity and electric demand, when considering a 12 percent reserve margin. The region still has surplus energy that is available on the non-firm energy market during a substantial portion of the year. Figure II-3 shows the projected resource capacity and the summer peak demand for the region over the next ten years.

Utilities and developers in the area have issued recent announcements of intent to build facilities. Units in Kentucky and southern Indiana have been promoted in the past few months. These units are gas-fired intermediate and peaking units. Table II-3 is a summary of the characteristics proposed for the units.

Figure II-3
ECAR Balance of Loads and Resources

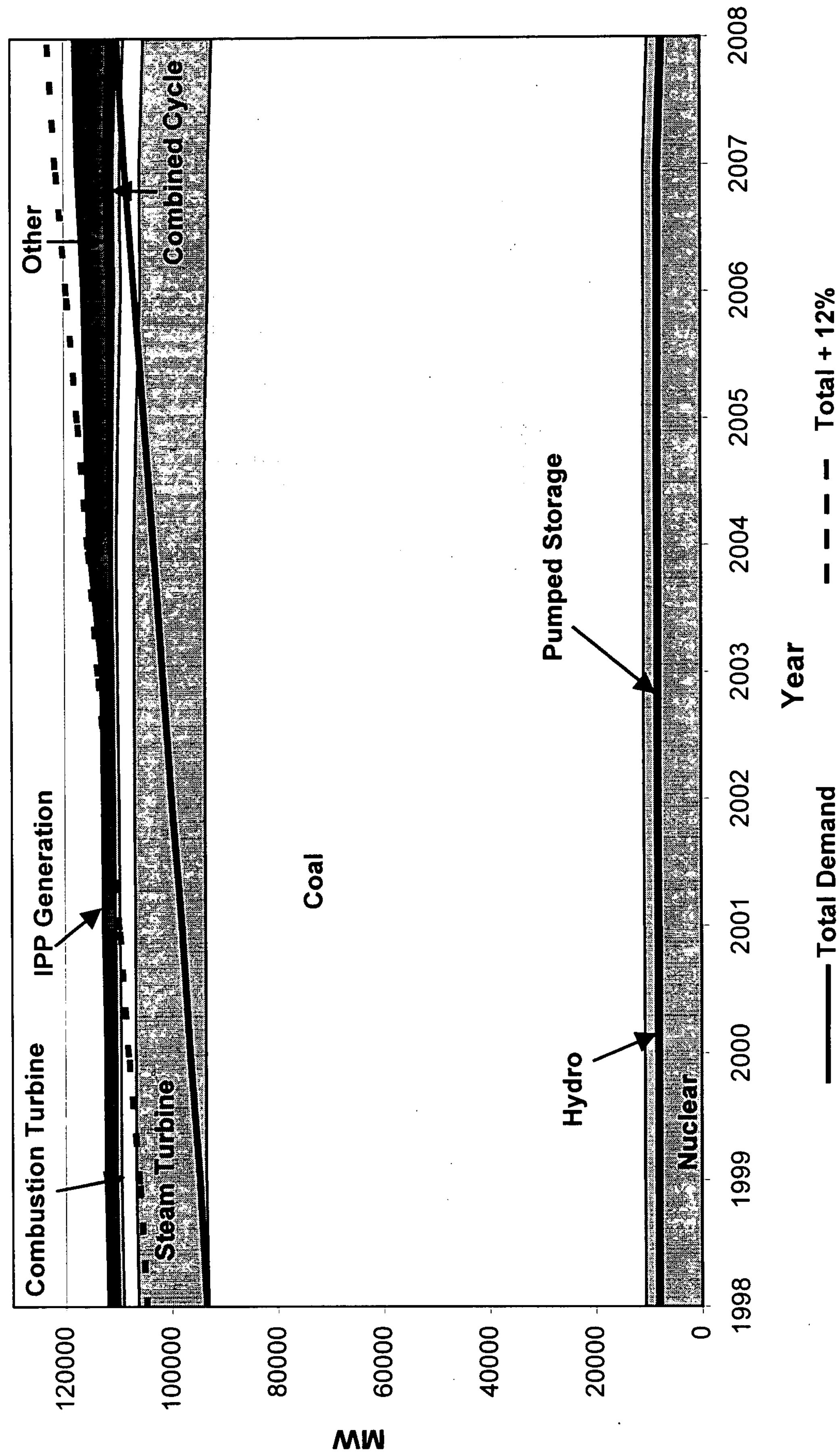


Table II-3

Planned Merchant Plant Activities Near Big Rivers Service Territory

St	Company	Plant	Site	Fuel	COD	Plant Capacity (MW)	Merchant Capacity (MW)	Status
KY	Columbia Electric Corp.	New Construction	Henderson	Gas-Fired		500	500	Proposed
KY	Enron Corp.	New Construction	Calvert City	Gas-Fired	2000	500	500	Proposed
KY	Dynegy Inc.	New Construction	Oldham City	Gas-Fired	2001	324	324	Proposed
IN	AES Corp.	New Construction	Worthington	Gas-Fired	2000	400	400	Proposed
IN	Enron Corp.	New Construction	Pike or Knox County	Gas-Fired	2000	500	500	Proposed
IN	LS Power Corp.	New Construction	Columbus	Gas-Fired	2002	800	800	Planned

INDUSTRY RESTRUCTURING (§8 (5) (g))

At this time no legislation mandating electric utility industry restructuring in the Commonwealth of Kentucky has been passed. Legislation that would open the Kentucky market to retail competition was proposed and studied by a legislative task force since 1998. However, it does not appear that any legislation will be passed in the near future.

The Kentucky Legislature created a task force to study electricity restructuring and report its findings by November 15, 1999. Because electric rates in Kentucky are among the lowest in the nation, the impacts of electric utility industry restructuring may be detrimental to Kentucky customers. National legislation mandating industry restructuring is currently being discussed in Congress.

Big Rivers should continue to monitor the progress of state and federal legislation to determine the potential impacts on the operations of the Big Rivers system.

* * * * *

Part III

Power Supply Screening Analysis

PART III
POWER SUPPLY SCREENING ANALYSIS (§8 (2))

The development of a power resource analysis requires creation of a mix of resources to evaluate. There are two basic categories for capacity and energy, owner constructed and purchases. As a first step in the analysis, Burns & McDonnell reviewed alternatives within these two categories. The fixed and variable costs were analyzed for each option. This part of the report describes the options reviewed, costs for the options and those determined to be carried forward to more detailed analysis.

OWNER CONSTRUCTED OPTIONS

There are several alternative generation technologies available for utilities to consider for construction in their service territories. Options considered for units to be built by Big Rivers include:

- Simple-Cycle Combustion Turbines
- Combined-Cycle Combustion Turbines
- Reciprocating Engine units
- Fuel Cells
- Renewable Resources (Wind and Biomass)

The addition of a coal-burning power generation facility was not considered in this screening analysis because of the limited capacity requirements of Big Rivers over the study period. The economics are typically not favorable for coal units of this size range because economies of scale are not achieved.

The fixed and variable costs of the first three alternatives were developed to provide the lowest cost options available. Costs were obtained from manufacturers, similar operations of other utilities and the Distributed Generation Guidebook for Municipal Utilities published by the Gas Research Institute and written by Burns & McDonnell in 1998. The project and operating and maintenance costs are included in Appendix B for the units considered.

Simple-Cycle Combustion Turbines

There are two major groups of combustion turbines. One group is based on units specifically designed for the electric industry. These are commonly referred to as frame units. The other is based on an engine used in jet aircraft and is called aeroderivative. The frame units are typically applied in units above 50 MW. The aeroderivative units are found in units below 50 MW. Another class of machines is being developed, the "microturbines". These units are kilowatt (kW) class machines and are aimed at the distributed generation market.

Combined-Cycle Combustion Turbines

A combined cycle unit is a combination of a combustion turbine, a heat recovery steam generator (HRSG) and a steam turbine. These units increase the efficiency of the combustion turbine by utilizing the waste heat from the combustion turbine to produce steam and drive a steam turbine generator. Efficiencies approaching 60 percent have been obtained for units in the 500 MW size range. The efficiency tends to decrease with size. Combined cycle units are more cost effective than a simple cycle unit if the energy requirements exceed about a 20 percent capacity factor.

Reciprocating Engine Units

There are numerous internal combustion engine sets being installed today. The units range in size from small kW machines to units rated in tens of MW. The units can be dual fueled using both distillate fuels and natural gas or propane. These units can be considered as distributed generation. As such, they can be located close to the end user and reduce the transmission delivery costs for power. Burns & McDonnell has assumed that the units would be fired on natural gas provided through a local gas distribution company.

Fuel Cells

The fuel cell power plant is a power generation technology which may achieve commercial availability in the near future. Fuel cell power plants use a chemical process to convert hydrogen and oxygen into water and electricity. The potential advantages of fuel cells include high efficiency, low emissions and noise levels, modular design which allows for short lead time, capability for capacity installations in small increments, and performance which is virtually independent of plant size. The operating and capital costs for potential fuel cell additions were based on information provided by fuel cell manufacturers. The fuel cells were assumed to be installed at a substation site for the purposes of the power supply screening.

Wind Turbines

Wind turbines ranging from a few kilowatts to about 2,500 kW are currently being operated at various sites throughout the United States. A number of commercial wind farms composed of small wind machines are currently supplying power to electric utilities on an avoided cost basis in Minnesota, Iowa, California, Hawaii, and elsewhere. These wind farms emerged as a result of federal and state tax credits and depreciation allowances for such technologies. Recently, 100-300 kW variable speed wind turbines, which benefit from increased efficiencies, have been developed. The costs used in the screening analysis were based on cost information from an 80 kW wind turbine installation in Iowa.

Biomass

The cost estimate used in the screening analysis for biomass generation is based on plantation-grown biomass converted to electricity in a conventional steam-turbine facility of 25 MW. Cost and operating information for this technology was primarily based on reports from the Oak Ridge National Laboratory on biomass generation including "Biomass Fuel from Woody Crops for Electric Power Generation". More research would need to be performed to determine a potential site for biomass generation.

FUEL COSTS

The primary fuel cost issue was the price to be assumed for the generating units. Estimating the cost of natural gas is always a challenge. Figure III-1 is a plot of the settle prices for forward contracts for natural gas traded on the New York Mercantile exchange. The data has been collected daily starting in 1997. Also shown on the plot is a polynomial trend line for the forward contracts. As seen, there has been a general increase in the pricing since the beginning of 1999. For purposes of the study, natural gas prices have been estimated to increase at a rate of approximately 1.5 percent. The starting price for the gas price was determined from the 1998 price of natural gas to Louisville Gas & Electric as reported in Resource Data International's PowerGen database of publicly available electric utility information.

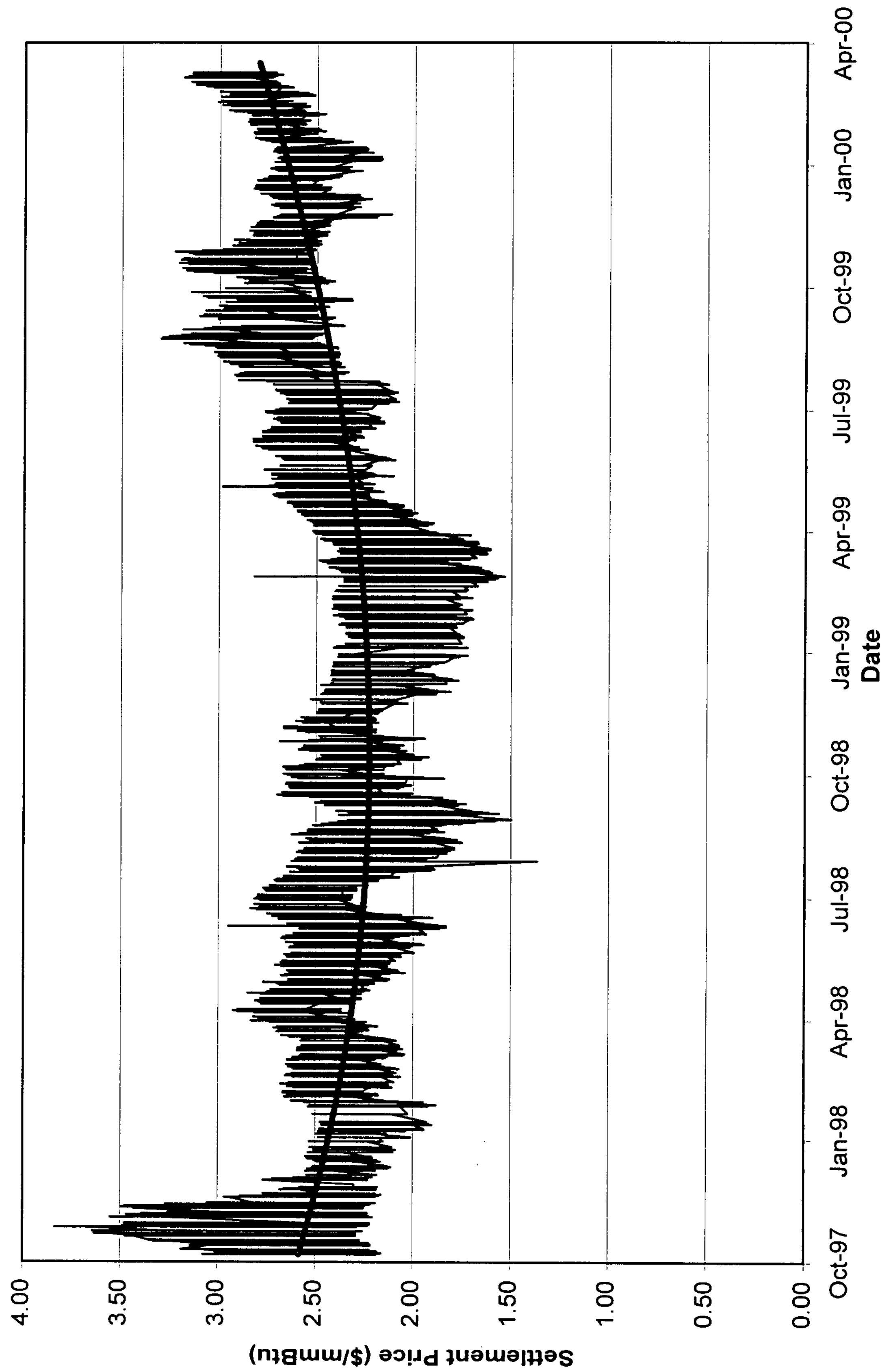
It is not anticipated that any other fuels such as coal or fuel oil would be utilized in generation additions by Big Rivers in the study period. Therefore cost estimates for these fuels were not developed for the IRP.

PURCHASES

Utilities can purchase capacity and energy in firm and non-firm contracts or purchase shares in generation facilities. Both of these options depend on the availability of surplus capacity in the area. Typically, capacity should be located where it is within one transmission wheel away from the purchaser to reduce the costs of delivery.

The ECAR region is beginning to run short of capacity based on information from the North American Electric Reliability Council's Electricity Supply & Demand database. Projected capacity margins are about 8 percent for the early 2000 time frame unless generation is constructed. Considering that the forced outage rate for nuclear and coal units can be greater than 5 percent, it leaves the region exposed to dependence on imports.

Figure III-1
NYMEX Futures Prices for Natural Gas



Contract Purchases

A contract purchase, for purposes of this study, is a purchase of capacity that is not necessarily dependent on a specific resource. Recent solicitations by Burns & McDonnell for other utilities in the region have shown a lack of response for these types of offers. However, peaking power may be available in the 2004-2010 time frame as required by Big Rivers. Recent peaking power supply offers evaluated by Burns & McDonnell for the years 2002-2004 have had capacity charges in the $4-$5/kW-month range and energy charges of approximately $100/MWh. The details of these offers are confidential but represent offers from power marketers.

Unit Purchases

The other type of offer is one made from a specific unit. There does not appear to be any surplus capacity available from coal units in the area. Due to the lack of realistic options, no unit purchases from coal facilities were modeled.

The area market is, however, seeing the announcement of intentions to build gas-fired simple and combined cycle units. One of the more popular arrangements being built today is a 2X1 F series combined cycle unit with a capacity of approximately 510 MW. This configuration has two 170 MW F series combustion turbines whose waste heat is fed into a heat recovery steam generator (HRSG). Steam from the HRSG drives a steam turbine generator rated approximately 170 MW. These units are for intermediate service and do not count as non-spinning reserve because they take about 90 minutes to bring on line. Also, the units are not suitable for numerous starts and stops due to their size.

There are currently five units being promoted in the area. Columbia Electric Corporation has recently announced that it is developing a 500 MW gas-fired power plant near Henderson, Kentucky. Enron is proposing to build two units that are to be 500 MW each. One of these units is proposed to be located in either Pike or Knox County, Indiana and the other unit is proposed to be located in Calvert City, Kentucky. Neither of these units are under construction but both are to be operational in June of 2000. AES is proposing to build a 400 MW unit that will be located in Worthington, Indiana. This plant is to be operational in the summer of 2000. Dynegy, Inc. is proposing to build a unit of 324 MW and this unit will be located in Oldham County, Kentucky. This unit is to be operational in 2001. A fifth unit is under construction in Vermillion County, Indiana by Duke Energy. The Vermillion plant will have a capacity of 640 MW with eight simple-cycle combustion turbines.

It was determined to develop the low cost options germane for Big Rivers from projects considered feasible for the projected needs. These costs would then establish offers to the promoters of the larger area projects and represent the maximum that Big Rivers could pay for someone else to provide the capacity and energy.

VOLUNTARY INDUSTRIAL CURTAILMENT

During the summer of 1999, Big Rivers worked with its members and their larger industrial customers to reduce load during times of peak demand. This program was well received by the member's customers and was mutually beneficial for Big Rivers, the member cooperatives, and their retail customers through the sharing of cost savings. Table III-1 shows the actual results of voluntary curtailment for July 30, 1999 from hour-ending 2 p.m. through hour-ending 7 p.m. Load reduction ranged from 17 MW to a high of 28 MW and the voluntary curtailment involved four industrial customers of Big Rivers' members.

Table III-1
1999 Voluntary Industrial Curtailment Results

Hour	Load Actual (MW)	Load Reduction (MW)	Load Resultant (MW)
14 (2 p.m.)	644	17	661
15	645	22	667
16	646	24	670
17	644	28	672
18	639	28	667
19	629	23	652

Big Rivers is expecting to expand the use of the program and has filed a Voluntary Curtailment Rider with the Kentucky Public Service Commission. The economics of the continued use of this program are evaluated later in this report.

POWER SUPPLY SCREENING RESULTS

Several sizes of each technology were selected to compare the operating costs at various capacity factors to screen the more applicable units for further review. The energy requirements from new capacity reviewed for Big Rivers are expected to be in the peaking and intermediate range based on the analysis of Big Rivers' load profile and LEM contract. The capacity factors for these types of resources are traditionally below 40-45 percent.

The relative levelized total costs of these options over a range of capacity factors are shown in Figures III-2, III-3, III-4, and III-5. The screening cost curves in these figures allow for a comparison of units over range of operating levels. The fixed and variable costs of each option are projected for twenty years of operation and levelized for a comparison of the economics of each unit.

Based on the projected loads and resources available to Big Rivers and the relative capacities and costs of the options reviewed, Burns & McDonnell selected the following power supply options to move into more detailed analysis:

- 45 MW LM6000 simple-cycle combustion turbine
- 53 MW LM6000 combined-cycle combustion turbine
- Combined-Cycle Unit Purchases
- Peaking Power Purchases
- Voluntary Commercial/Industrial Load Management Program

* * * * *

Figure III-2
Screening Analysis of Generation Options
Combustion Turbine Engines

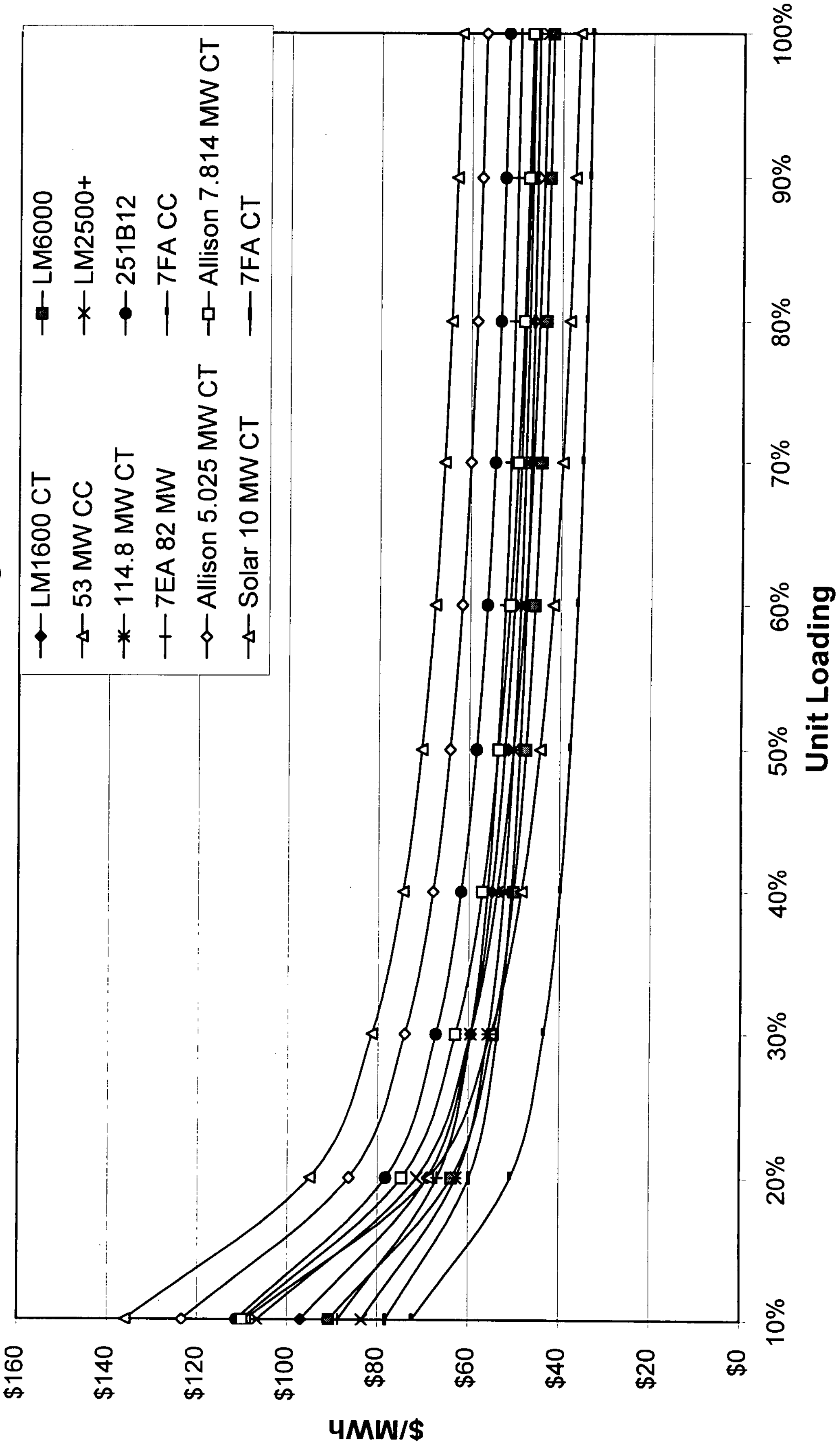


Figure III-3
Screening Analysis of Generation Options
Reciprocating Engines

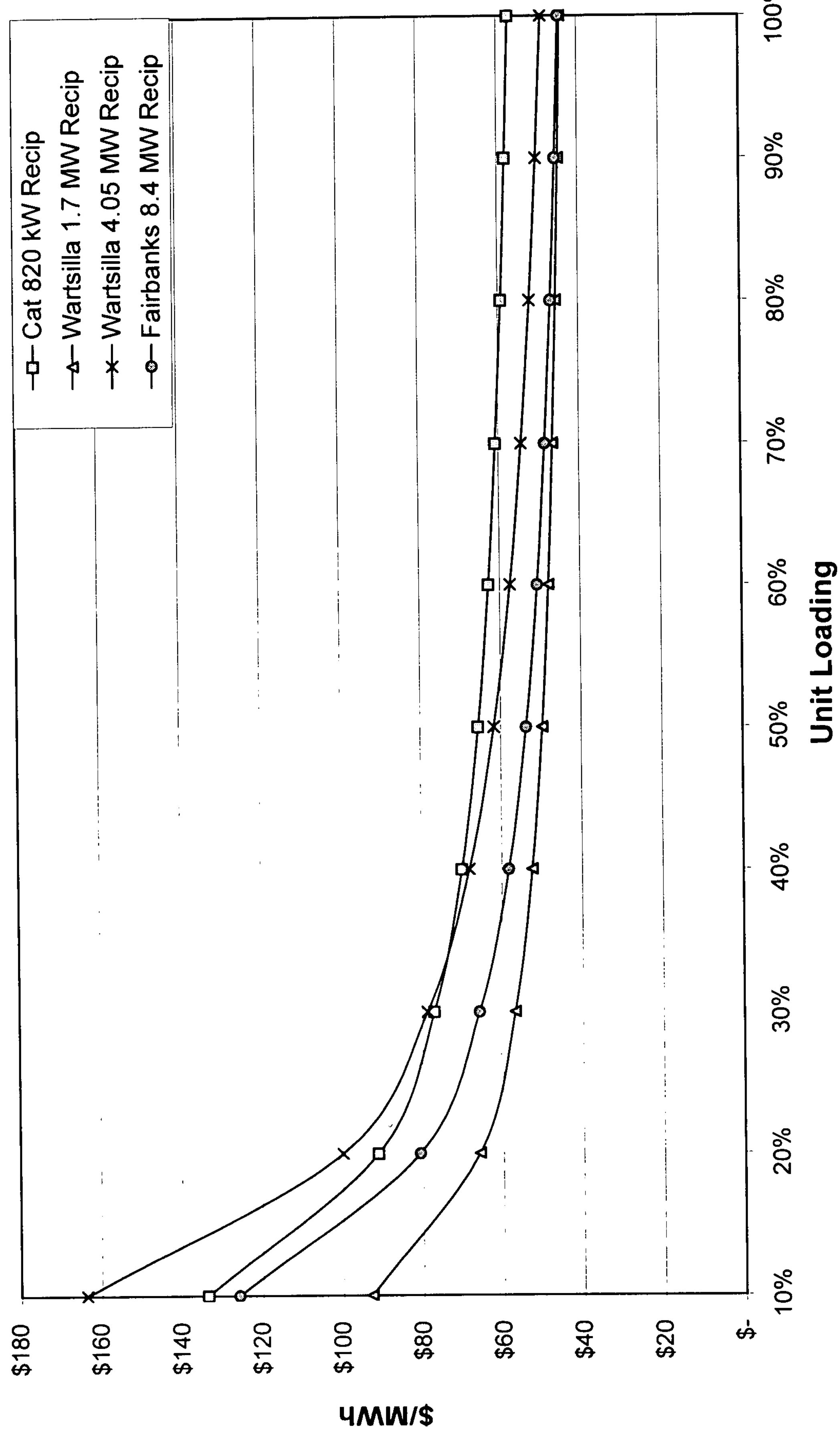


Figure III-4
Screeening Analysis of Generation Options
Microturbines, Fuel Cells, and Renewable Resources

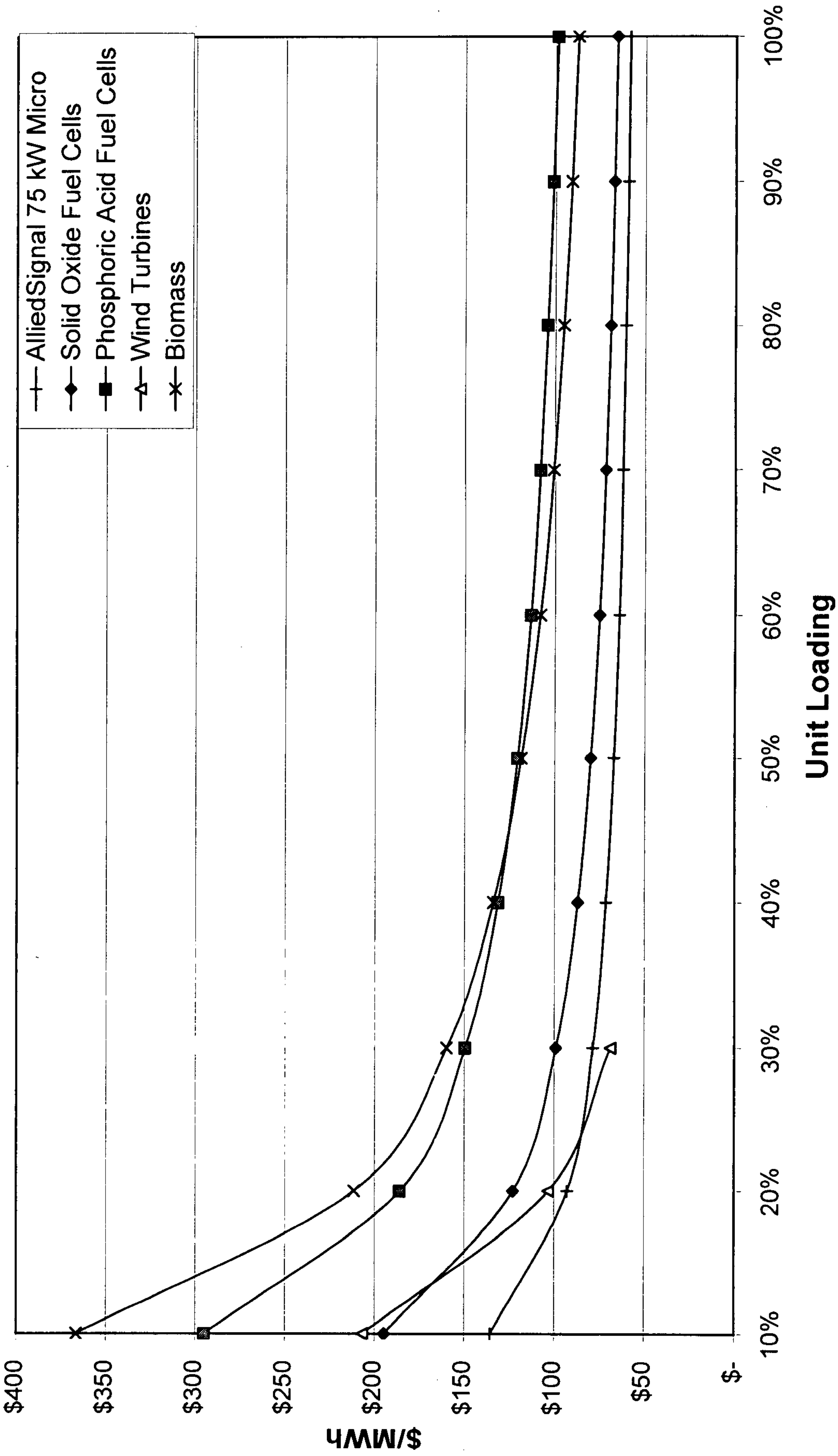
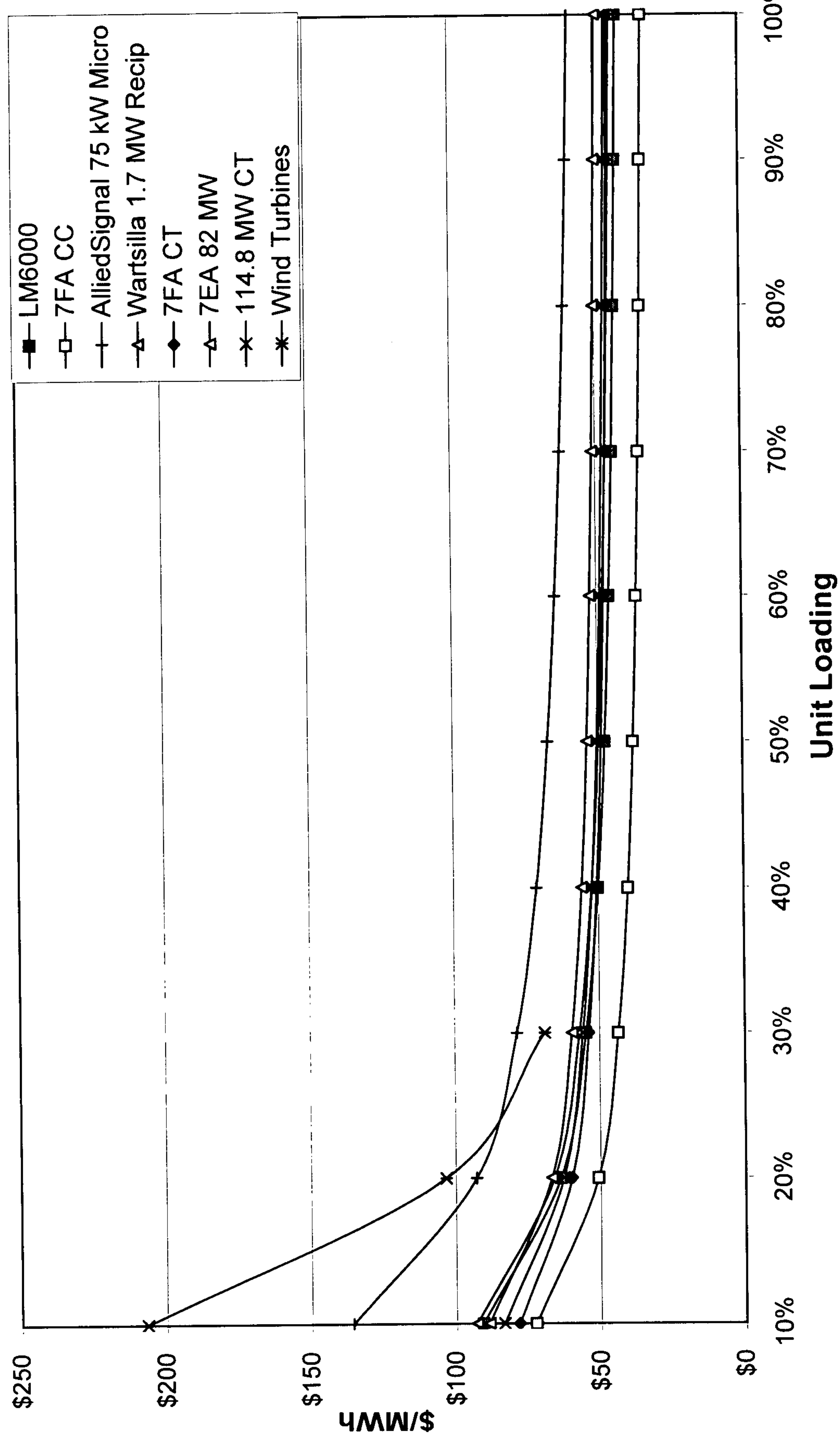


Figure III-5
Screening Analysis of Generation Options
Lowest Cost Options for each Technology



Part IV

Demand-Side Management Screening Analysis

PART IV
DEMAND-SIDE MANAGEMENT SCREENING ANALYSIS

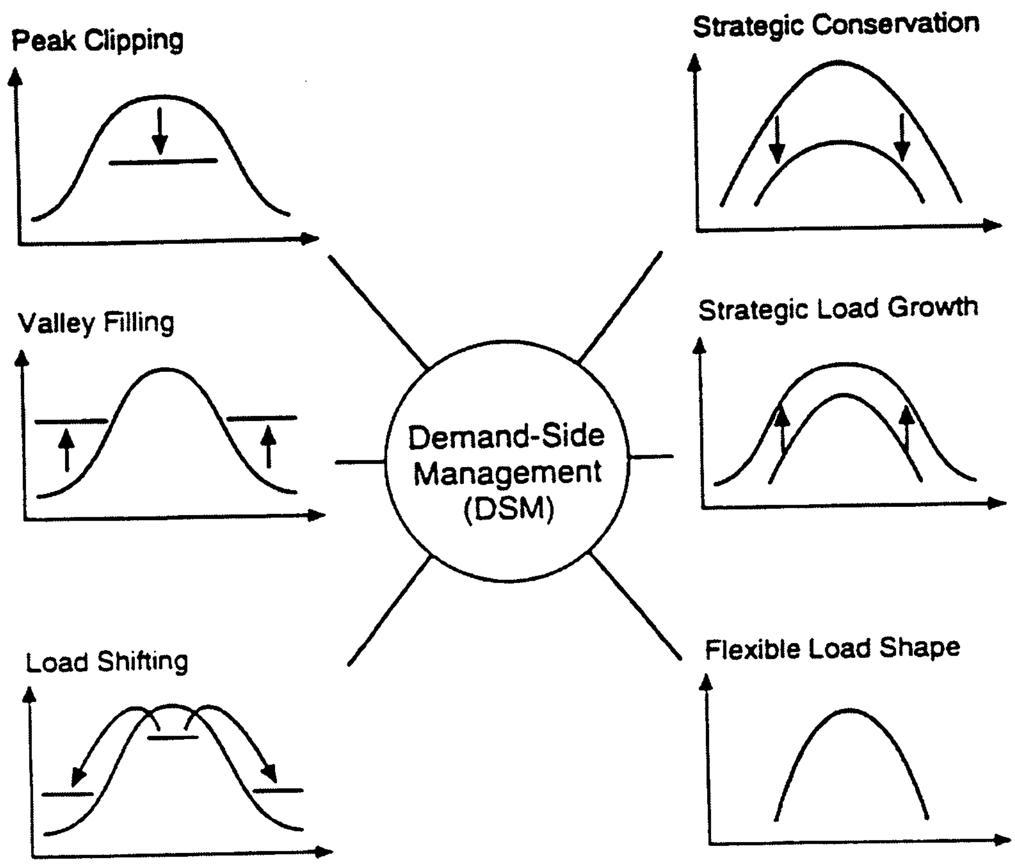
INTRODUCTION

The origins of Demand-Side Management (DSM) lie in the concept of Least Cost Planning as it evolved during the 1980's. In a regulated environment, DSM provided utilities with peak reduction, valley filling and overall load-shifting as three of the principle parts of a four-option program originally developed by the Electric Power Research Institute (EPRI) for member utilities. The remaining components of the original mix of programs were strategic load growth, strategic conservation and eventually load management.

In concept, load control or load management fulfilled the requisites of load shifting, providing utilities with all the benefits and few of the detriments afforded by the other DSM options.

Figure IV-1

The Six Classical DSM Types



As deregulation and competition appeared in the 1990's, most DSM options became obsolete, were severely modified, or eliminated altogether. The negative rate impacts of many programs, employing cash incentives to promote the purchase of more efficient electrical equipment, were further exaggerated by lost revenues and negative rate impacts.

All of the conservation programs offered to customers by American utilities were tailored to serve three specific rate classes: residential, commercial and industrial. The largest fractional portion of all funding invested in DSM has been devoted to commercial programs. Any detailed study will conclude that commercial and industrial DSM, when properly implemented, returns the greatest benefit for utilities, with the least negative impacts.

As Big Rivers completes its current Integrated Resource Plan, several factors must be considered in establishing which "real" DSM options will serve both the utility and its member's customers. While each utility is unique, based on demographics, location, fuel mix, etc., Big Rivers is particularly sensitive to financial pressure given its recent bankruptcy and restructuring.

Significant care should be taken to ensure that Big Rivers' financial standing is supported and not negatively impacted by the resource mix for both supply- and demand-side.

CURRENT SITUATION

A review of the forecast of electric load included in the Big Rivers Power Requirement study, recently completed by Burns & McDonnell, indicates that the utility has surplus capacity, and will continue to be in this same position until 2004 or 2008 depending on the installation of Kenergy's customer's generation. This capacity is provided by its contracts to purchase capacity and energy from the SEPA and LEM.

Both contracts provide Big Rivers with long-term reliable and inexpensive power. The supply-side analysis of Big Rivers' resources mix indicates:

- No need for additional capacity in the immediate future with the installation of 62 MW of generation by Kenergy's customer.
- Big Rivers enjoys a healthy load factor (60%) and a demand-mix which is heavily weighted toward industrial users (47%) not including the aluminum smelter loads.

- Current contract with LEM is priced in such a way that Big Rivers can sell surplus power to its neighboring utilities at a profit, and by doing this increase its cash reserves and lower its member revenue requirements.

Big Rivers should only implement DSM programs that bolster its current capacity position, increase cash flow and mitigate rate pressure on the company and its member's customers. Furthermore, any program implemented must provide verifiable, cost-effective capacity reduction or load shifting, if it is to benefit Big Rivers.

VIABLE DSM OPTIONS (§8 (2) (B))

An initial analysis of all DSM options indicates that Big Rivers will benefit most from programs that increase load factor and revenues, while reducing coincident peak capacity needs. This type of program will allow Big Rivers to capitalize on future capacity sales while bolstering its financial status. Among all DSM options considered by Burns & McDonnell for Big Rivers, the following trends emerge:

- Strategic conservation programs reduce load at all hours. This reduces sales and has a general tendency to increase revenue requirements and increase rates.
- Load shifting programs such as Load Management will have the most beneficial impact on Big Rivers. These programs will increase off-peak sales, reduce peak demand, and have a positive rate effect and total resource impact on the utility. In summary, programs of this type can be considered a win-win option for Big Rivers and its member cooperatives.
- As can be seen in Table IV-1, Big Rivers has an excellent load factor and sufficient capacity to cover demand for five to nine years depending on the installation of Kenergy's customer's generation and the successful implementation of the voluntary curtailment option.

A HISTORICAL PERSPECTIVE

A comprehensive DSM study undertaken by Big Rivers and prepared by R. W. Beck in 1995 considered and analyzed several hundred DSM options for future implementation by Big Rivers. Of all resources originally considered, a limited subset of residential and commercial programs passed the cost-effectiveness criteria of the Total Resource and Rate Impact Tests. The Total Resource Cost (TRC) test is a measure of a program's benefits versus costs for all ratepayers, and is sometimes called the "all ratepayer" test. The Rate Impact Test (RIM) is a measure of rate impacts for a utility. Ratios greater than 1.0 are considered beneficial.

The programs considered for implementation were studied individually and then grouped into plans. These plans were then studied for Total Resource Cost (TRC) and Ratepayer Impact Measure (RIM) evaluation. Two TRC programs (residential space conditioning efficiency and residential water heater efficiency) and four RIM programs (residential water heater replacement and air source heat pump with two identical programs on the commercial side) were found to be cost effective.

Table IV-1
Total System Energy Requirements and Load Factors
Historical and Projected

	With Smelter Load		Without Smelter Load		
Year	Total System Demand (kW)	Load Factor	Total System Demand (kW)	Load Factor	
1994	1,213,454	70.1%	509,546	59.6%	
1995	1,143,967	79.4%	552,813	61.1%	
1996	1,159,973	77.6%	565,744	60.8%	
1997	1,196,455	77.0%	597,653	61.1%	
1998	1,266,443	76.1%	661,374	59.8%	Historical
1999	1,368,628	79.9%	682,628	61.6%	Projected
2000	1,402,785	79.7%	716,785	62.3%	
2001	1,421,408	79.4%	735,408	62.2%	
2002	1,437,267	79.2%	751,267	62.2%	
2003	1,453,132	78.9%	767,132	61.9%	
2004	1,467,527	78.6%	781,527	61.7%	
2005	1,483,063	78.3%	797,063	61.5%	
2006	1,499,929	78.0%	813,929	61.4%	
2007	1,512,954	77.8%	826,954	61.2%	
2008	1,528,733	77.5%	842,733	61.0%	
2009	1,548,305	77.2%	862,305	60.9%	
2010	1,579,135	77.2%	893,135	61.6%	
2011	1,595,557	77.0%	909,557	61.4%	
2012	1,612,593	76.7%	926,593	61.2%	
2013	1,635,437	76.5%	949,437	61.3%	

The former DSM study was conducted in 1995. Marginal costs for Big Rivers have fallen since that time while the efficiency of DSM technologies in each specific area has increased due to technical and market transformation.

Given the current trend toward deregulation and competition, most options considered in the original study have become less cost-effective. In many cases, potential benefits have been substantially reduced and may even be negligible.

The most cost-effective programs involved replacement of water heaters and non-electric heating systems (at failure). It does not appear that the 1995 study considered the impacts of free riders and free drivers. Burns & McDonnell's analysis of these programs indicates that given the current pricing structure and efficiency, Big Rivers will either benefit marginally or break-even but must expend considerable capital in order to implement these programs. Given the current financial standing of the utility, the financial risks far outweigh the potential benefits.

LOAD GROWTH OPTIONS

Several options recommended by the 1995 DSM study involved switching from natural gas to electric. Most of these, however, involved costly equipment replacement. Residential consumers are less likely to switch from less expensive natural gas powered appliances such as furnaces and water heaters to their more expensive electric counterparts. Among these are ground source heat pumps and water heaters.

While gas prices have increased and electric rates have dropped, these programs are bound to have little public appeal. These programs will increase peak demand and promote strategic load growth for the utility, but might not impact load factor. In order to make them more favorable for member's customers, Big Rivers would have to provide a financial incentive for the member's customers to move toward greater acceptance and eventual market transformation.

There are several components to the cost side of implementing incentive programs at electric utilities. Among these are:

- Program research and development costs
- Marketing and promotion costs
- Financial incentives
- Program operating and maintenance costs
- Costs associated with measurement and verification

For these or any other program to be cost effective for Big Rivers, the benefits must exceed the overall costs of implementation. Given Big Rivers' current situation, these programs would drain both personnel and financial resources while providing little benefit to the utility, reduce the utility's ability to sell energy to neighbors, and provide minor increases in revenue. A preliminary analysis indicated that neither is beneficial to Big Rivers.

LOAD MANAGEMENT BY AND FOR BIG RIVERS

The best option for Big Rivers is an internal supply-side management program where resources are managed in a way that optimizes efficiency and minimizes member's customer's interruptions and unscheduled purchases of capacity. Such a program will optimize revenue from capacity sales, minimize member's customer's interruptions, and therefore maintain customer satisfaction.

LOAD MANAGEMENT IN THE "NEW" ENVIRONMENT

Big Rivers is an optimal candidate for a focused, low-cost load management program. With today's technology, it is possible to implement load management without the cumbersome hardware and personnel requirements of traditional programs. The traditional method involves costly equipment to implement and maintain, and requires a long lead-time as systems are purchased, installed, and tested.

Load management can be implemented in several ways:

1. Using radio controlled modules managed from a central location by the utility (traditional method).
2. Using innovative rate structures where member's customers control their consumption based on capacity costs, and where member's customers can review their consumption and bills on the Internet.
3. Implementing an interruptible rate structure for their member's large customers. This can include reduced rates at all hours or a shared savings contract when the customer is asked to reduce load, with a limited number of 8-hour interruptions per year.

VIABLE LOAD MANAGEMENT OPTIONS (§8 (3) (e))

Big Rivers will benefit most from a selective implementation of either method 2 or 3. Both have been proven to reduce coincident peak demand while maintaining the member's customer's satisfaction. Additionally, both methods have been used successfully by major utilities including Austin Energy and Florida Power & Light. Their programs are outlined below.

Austin Energy, the municipal electric utility in Austin, Texas has implemented a very successful customer controlled load management program and has successfully reduced demand using this program since 1996. Participation in the Austin Energy program is voluntary, and customers are outfitted with a time-of-use meter that is connected to the customer's telephone line. Consumption data is transmitted to the utility's time-of-use server every night between midnight and 5 a.m. and the computer automatically formats the data into a site-specific loadshape. Raw consumption data is stored for billing purposes and used to generate the customer's bill.

Customers are provided with direct feedback via the Internet. They log onto the utility's web page and can access a customized web page showing their usage during the previous 24-hour period, their usage during the current month, past month, as well as usage during any period since they joined the program. The program was initially limited to residential customers but has since been opened to commercial customers. Austin Electric has a very small industrial load. The web page for this program can be accessed at www.electric.austin.tx.us. The manager for this program is Mr. Madjid Zehani. Burns & McDonnell recommends that Big Rivers contact Mr. Zehani (513-322-6400) and gain on-line access to Austin Energy's customer website. This may provide further insight on state-of-the-art time-of-use and customer controlled load management.

Another large utility, Florida Power and Light Company (FPL) instituted an interruptible load program for commercial and industrial customers in the mid 1980's. That program is based on a reduced year-round demand and energy rate for customers. Customers are called and advised of possible interruptions 24 hours before they occur. Under this program, customers can be interrupted up to 8 times per year, only on peak days, and for periods not to exceed 8 hours each. FPL has successfully used this program for almost 15 years and has rarely interrupted customers. Because the utility has enlisted more than 600 MW of interruptible capacity reduction, interruptions are called on a revolving basis in order to minimize disruptions.

Participants in the commercial/industrial (C/I) program should contractually agree to the following:

1. To remain customers of Big Rivers' member cooperatives for at least 7 years from the date of subscription.
2. To reduce demand or curtail operations to the agreed level during the required period, not to exceed 8 hours per curtailment, nor 8 curtailments per year, upon 24 hour notification by Big Rivers' member cooperatives.
3. To consider further curtailments, in cases of extreme emergency, upon notification by Big Rivers' member cooperatives and negotiation of one-time financial incentives, as necessary.

Table IV-2
Commercial / Industrial Load Management Program
Potential Capacity Reduction by Year

Year	New Managed Capacity (MW)	Total Managed Capacity (MW)	System Demand Before DSM (MW)	System Demand After C/I DSM (MW)
2000	30	30	716.8	686.8
2001	10	40	735.4	695.4
2002	10	50	751.3	701.3
2003	10	60	767.1	707.1
2004	10	70	781.5	711.5
2005	10	80	797.1	717.1
2006	0	80	813.9	733.9
2007	0	80	827.0	747.0
2008	0	80	842.7	762.7
2009	0	80	862.3	782.3
2010	0	80	893.1	813.1
2011	0	80	909.6	829.6
2012	0	80	926.6	846.6
2013	0	80	949.4	869.4

COST OF C/I PROGRAM

Given the current status of Big Rivers' purchase agreements and their need for occasional load reduction, Burns & McDonnell has recommended two main alternatives in commercial / industrial DSM. Both of these alternatives rely on voluntary curtailments of member's customers and are projected to provide up to 80 MW of coincident reduction during the study period based on Big Rivers' member cooperatives' commercial/industrial load and the potential for customer curtailments. In order for this program to be successful and accepted by customers, two important elements must be present:

- Continued satisfaction of the member's customer
- The feeling among participants that they too are financially benefiting from the curtailment

As stated previously in this report, one very successful program undertaken by Florida Power and Light Company reduced customer tariffs altogether for participants, thus assuring that customers were financially remunerated both when interrupted and at times when interruptions were not occurring. While this type of program appears more expensive, Big Rivers should review its current rate structure and consider this as an alternative solution. The implementation of this tariff would typically be at the distribution cooperative level with financial support from the generation and transmission cooperative. A typical tariff of this type, filed by a utility with the Public Service Commission of Florida, has been included in Appendix E.

The second type of program involves a "shared" savings approach during the period of interruption. The cost comparison for the shared savings is based on the marginal cost paid by Big Rivers at times when capacity costs are at their highest and demand must be met by making a spot market purchase.

A review of the spot market prices for the last twelve months indicate that during those hours when the LEM contract alone did not cover the requirements of Big Rivers, the average annual price of spot market electricity was $58.75 per MWh. This price escalates considerably during the peak summer months, and when computed for the months of July and August, 1999, the cost is $84.40 per MWh. It can be assumed that this cost will escalate with time at a rate similar to inflation (3% in Table IV-3) barring unforeseen economic downturns, dramatic increases in demand, or shortfalls in supply.

Based on the data developed in Table IV-3 and the recommended reduction as it escalates and then levels off, the overall costs for the program can be developed. In developing this number, the assumptions used in similar programs have been incorporated. These include a maximum number of interruptions per year (8 instances) with a maximum period of interruption per instance (8 hours). Accordingly, each member's C/I customer participating in the program can be interrupted no more than 64 peak-period operating hours per year.

Table IV-3
Shared Savings for C/I DSM Program

Year	LEM Cost $/MWh	Escalated Purchased Cost $/MWh	Savings $/MWh	Shared Savings $/MWh
2000		$84.400		
2001		$86.932		
2002		$89.540		
2003		$92.226		
2004		$94.993		
2005		$97.843		
2006		$100.778		
2007		$103.801		
2008		$106.915		
2009		$110.123		

As can be seen in Tables IV-3 and IV-4, the cost of the program reflected in the shared savings is moderate, and has been tailored to maximize the interruption period of 64 year-hours per MW. The cost portion of the program is equal to the savings experienced by Big Rivers, given typical conditions and assumed rates for spot market purchases.

Table IV-4
C/I Program Costs for "Typical" Year

Year	MW Managed	Managed MWh	Cost per MWh	Cost per Year
2000	30	1920	$32.74	
2001	40	2560	$34.01	
2002	50	3200	$35.21	
2003	60	3840	$36.50	
2004	70	4480	$37.84	
2005	80	5120	$39.21	
2006	80	5120	$40.63	
2007	80	5120	$42.04	
2008	80	5120	$43.45	
2009	80	5120	$44.90	

RESIDENTIAL PROGRAM

Any residential component of DSM for Big Rivers will be significantly less cost effective than the commercial/industrial program. The primary motivating factors for instituting residential DSM at this time are regulatory requirements or the need for increased customer satisfaction in the face of competition. Either situation would still require extensive screening and potential marketing studies to establish optimal return. A minimal program offering 1 MW per year of capacity reduction could be instituted by Big Rivers for the member's residential customers.

While there are several options for instituting this program, minimizing capital cost and maximizing benefits is an essential component for Big Rivers. Several options stand out as possible programs on the residential side.

1. Residential Water Heater Timers. Timers provide customers with increased control over water heater demand, and when set properly, will benefit the utility with reduced demand and minimal loss of sales. Customers can be instructed to set thermostats at 140 degrees Fahrenheit. Timers are then set to run water heaters in the early morning hours, before the morning peak (in winter) and late in the morning during the summer peak period. In this way, the utility benefits from load shifting, while customers experience little if any discomfort from the program. Given the low cost of timers ($39 per unit average in the U.S. market) and a minimal installation cost ($50 per home), total program cost will remain under $100 per participant.

2. Water heater wraps. This program was also found to be cost effective in the 1995 DSM study. The cost of water heater wraps, when purchased in bulk is approximately $19 per installation. Wraps can either be installed by the utility, or provided to customers for self-installation. When installed in combination with a water heater timers, the impact is greater, customer satisfaction is increased, and installation costs are minimized.

Residential Program Impacts and Costs

Due to their low cost-effectiveness, residential programs should be limited to 5 MW total over the study period, if implemented at all. In the best of all worlds, Big Rivers would eliminate residential participation for DSM programs and repackage programs as "Customer Satisfaction" options offered to the customers. Any program implemented in this way should include a customer retention contract whereby the customer agrees to remain a customer of Big Rivers' member cooperative for a fixed period of time. Once a total coincident reduction of 5 MW is achieved, the program should be maintained without further growth.

Given the options presented, the cost for the residential program can vary substantially, with the least expensive option being water heater wraps ($19 to $25 per installation with a typical diversified coincident demand reduction of 100 watts per unit installed). Accordingly, the water heater wrap program will provide DSM to Big Rivers at a cost of $190 per kW.

Residential water heater timers ($50 to $100 per installation and a typical diversified coincident demand reduction of 1kW per unit installed). While more expensive on a per-unit basis, provide greater reductions and can provide Big Rivers with DSM at $100 per kW, installed.

Burns & McDonnell does not recommend the inception of a residential DSM program. However, if it is determined that residential participation in DSM would be beneficial from a regulatory perspective, then a combination of water heater DSM options will increase member's customer's satisfaction and provide a more balanced offering to all customer classes.

RECOMMENDATIONS

As part of this Integrated Resource Plan, Burns & McDonnell recommends that Big Rivers should continue its current evaluation of the implementation of a combined commercial/industrial load managemnet plan. The largest portion of this plan should target member's industrial customers with large coincident demand and should provide an incentive for participation. This incentive can be either an interruptible rate, a shared savings payment or the market-based tariff for curtailing demand at times when the utility is facing extraordinary constraints or unusually high cost for additional capacity. The approval of Rate Schedule 10 by the Kentucky Public Service Commission is a solid first step in the implementation of this recommendation. The identification of member's industrial customers suitable for this program will be an ongoing process that should build upon the current foundation of the program.

* * * *

Part V

Production Cost Modeling

PART V
PRODUCTION COST MODELING

This part of the report describes the steps that were taken to model the Big Rivers system's cost of production through the use of detailed production cost modeling. It provides a description of the production cost modeling used to evaluate the alternatives and the results of the modeling.

MODELING OBJECTIVES

During the years 1999-2013, the system peak demand is larger than the LEM contract maximum capacity. However, this capacity deficiency is reduced, and in some years eliminated, with the capacity associated with the SEPA contract. The SEPA contract provides 178 MW of capacity during the years 1999-2013 but the associated energy from this contract is limited as described in Part III. Taking into account the expected addition of 62 MW of generation by one of Big Rivers' member cooperatives' customers, the demand of Big Rivers exceeds the capacity associated with the LEM and SEPA contracts during the years 2008-2010. Meeting the demand and energy requirements during this time frame is the primary focus of the production cost modeling, however the potential for providing off-system sales throughout the study period is also addressed. If the 62 MW is not installed as planned, the Big Rivers system will be capacity deficient from 2004 through 2011. This scenario is addressed in Part VI – Risk Assessment.

Projected load duration curves for Big Rivers for the years 1999-2013 including the expected 62 MW of Kenergy's customer's generation may be found in Appendix C. The load duration curves are useful in determining the projected capacity and energy unmet by the LEM contract.

PRODUCTION COST MODELING (§8 (5) (a&b))

Burns & McDonnell developed a spreadsheet model to simulate the dispatch of Big Rivers' power supply resources for the years 1999-2013. The model dispatched the available resources on an hourly basis taking into account both hourly, monthly and annual contract maximums and minimums and the contract prices and spot market price estimates. The output of the model contained the energy dispatch and costs associated with meeting the hourly requirements of Big Rivers. The model also utilized the electricity spot market index prices for the last twelve months to determine the potential for non-member electricity sales and revenues in the future. Because of the firm nature of Big Rivers' purchases and the lack of generating capacity, the model does not need to include the forced outage rates, heat rates, fuel and operation and maintenance costs that are utilized by typical production cost models.

Both existing and potential future resources were input to the model in a series of cases to determine the most cost-effective method of meeting future power supply needs. The cases were evaluated with and without the sales of surplus power. Sales of surplus energy and purchases of energy to meet load requirements were made at the projected spot market prices determined from the actual daily spot market prices of the last twelve months. The actual daily prices of the last twelve months were annually escalated by the projected spot market price escalation rates included in the Department of Energy's Annual Energy Outlook 2000 and included in Appendix F. This forecast reflects an average annual inflation adjusted price increase of 3.6% over the study period. Capacity deficiencies were assumed to be met through the purchase of peaking capacity in all cases.

Based on the results of the screening analyses described in Parts III and IV, five power supply options were considered in the production cost modeling. These options included generation, purchases, and demand-side management options. All cases were designed to meet the demand requirements of Big Rivers and modeled with and without the projected non-member sales of surplus capacity and energy. The highlights of each case are described in the paragraphs below.

Key assumptions and judgments that were used in the analyses include:

- Load forecast assumptions described in Appendix A
- Operation and maintenance cost escalation rate and inflation rate – 3.5%
- Natural gas escalation rate – 1.5%
- Long-term interest rate and discount rate– 6.5%
- Spot market price forecast based on 1999 spot market prices and the Department of Energy's price forecast

The spot market price forecast and natural gas price forecast were seen to have the largest impact on the plan and therefore were further analyzed in Part VI Risk Assessment.

Case 1 - 45 MW Combustion Turbine Addition

One of the lowest fixed cost resources for Big Rivers to consider is a combustion turbine. These units are considered by utilities that are primarily in the need for capacity operated less than 10 percent of the year. The current market for combustion turbines has become extremely active since the summer of 1998. Costs have escalated approximately 25 percent and lead times for delivery have stretched to 2002. The 45 MW unit was selected from the screening analysis. These units are also more readily available than larger machines. This case included the addition of a 45 MW combustion turbine in 2002 to meet anticipated load growth and supplement existing purchase power contracts. The case was also run with the installation of the CT delayed until 2009.

Siting for this unit was considered to be on an interstate gas line with access to the Big Rivers transmission system. The modeling assumptions for this case are provided in the Appendices.

Case 2 – 53 MW Combined Cycle Addition

In utilities where the need for low cost energy is increasing, a gas-fired combined cycle unit is the current unit of choice. The 53 MW unit was considered for the system as being one of the smaller capacity units available that still provided an efficient heat rate. This case included the addition of a 53 MW combined cycle unit in 2002. The case was also run with the installation of the unit delayed until 2009.

Siting for this unit was considered to be on an interstate gas line with access to the Big Rivers transmission system. The modeling assumptions for this case are provided in the Appendices.

Case 3 – Combined Cycle Capacity and Energy Unit Purchases

The ECAR region has very little summer capacity for sale. There are units being proposed for the area by utilities and independent power producers. Recent solicitations by Burns & McDonnell for other clients have provided the IPP pricing structure for similar units and were used in the study. Based on these solicitations capacity charges were assumed to be $6/kW-month in 1999 escalating at the rate of inflation. The demand charges for these purchases include charges of $1.50/kW-month for wheeling across one system throughout the study period. The cost of energy was calculated using a heat rate of 7100 Btu/kWh, the same gas costs as projected for potential Big Rivers generation, and variable operation and maintenance costs of $2/MWh escalated at the rate of inflation.

Case 4 – Peaking Capacity and Energy Purchases

Peaking capacity and energy may be available during the time period of Big Rivers' capacity deficiencies. Recent peaking power supply offers evaluated by Burns & McDonnell for the years 2002-2004 have had capacity charges in the $4-$5/kW-month range and energy charges of approximately $100/MWh.

For the production cost modeling of this option, peaking purchases were assumed to be made from 2008 to 2010 to meet the capacity deficiencies projected for Big Rivers. Capacity charges were assumed to be $5.40/kW-month in 2008 escalating to $5.60/kW-month in 2010. The capacity charges for these purchases include charges of $1.50/kW-month for wheeling across one system throughout the study period. The energy charges were assumed to be $100/MWh throughout the purchase period.

Case 5 – Commercial/Industrial Load Management Program

The voluntary commercial/industrial load management program outlined in Part IV of this report is modeled in Case 5. The shared savings approach was assumed with half of the reduced cost or increased revenue resulting from the interruption being passed on to the member's customer. Sixty-four hours of interruption were assumed for each year consisting of eight, eight-hour periods.

RESULTS (§8 (5) (c))

The annual cash expenditures from the production cost modeling are included in Tables V-1 and V-2. The difference between the two tables is the assumption on the sale of surplus capacity and energy to non-members. Due to some of the options installing more capacity than can be used in the study horizon, it is assumed that capacity sales of the surplus will be made to ECAR area utilities or power marketers. These sales were assumed to be made for $3.50/kW-month in 1999 increasing to $4.90/kW-month in 2013 with an annual increase of $0.10/kW-month. These prices are reflective of capacity market sales prices in the region based on recent bid evaluations by Burns & McDonnell.

Non-member sales of surplus energy were made at the projected spot market prices determined from the actual daily spot market prices of the last twelve months. The actual daily prices of the last twelve months were annually escalated by the projected spot market price escalation rates included in the Department of Energy's Annual Energy Outlook 2000 and included in Appendix F. The spot market sales reflect a best-case scenario with all available energy being sold at the spot market price.

Tables V-1 and V-2 show the potential economic benefit of the commercial/industrial load management program (Case 5). In the scenario without non-member sales, Case 5 is the lowest cost resource option over the 15-year period as a result of the load reductions and avoided payments for peaking capacity purchases in some years. The relative net present values of the cases are shown graphically in Figures V-1 and V-2.

The scenario with non-member sales reflects the potential for off-system sales by Big Rivers. The sale of surplus energy from the LEM contract represents the largest portion of revenues from sales to the spot market but the installation of generating units in Cases 1 and 2 and the purchase of combined cycle unit capacity in Case 3 provide a significant source of sales. Case 2 with a 53 MW combined cycle unit provides the greatest amount of off-system sales from the resource additions analyzed and the greatest

Table V-1

COST SUMMARY TABLE FOR ALL CASES WITHOUT SALES OF SURPLUS CAPACITY AND ENERGY

Big Rivers Electric Corporation

Year	*Case 0*	*Case 1* 2002	*Case 1* 2009	*Case 2* 2002	*Case 2* 2009	*Case 3* 2002	*Case 3* 2009	*Case 4*	*Case 5:*
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

Table V-2

COST SUMMARY TABLE FOR ALL CASES WITH SALES OF SURPLUS CAPACITY AND ENERGY

Big Rivers Electric Corporation

Year	Case 0	Case 1		Case 2		Case 3		Case 4	Case 5:
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

The projected revenues reflected in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues reflected in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Figure V-1
Comparison of Net Present Value of Total Costs
Without Sales of Available Surplus

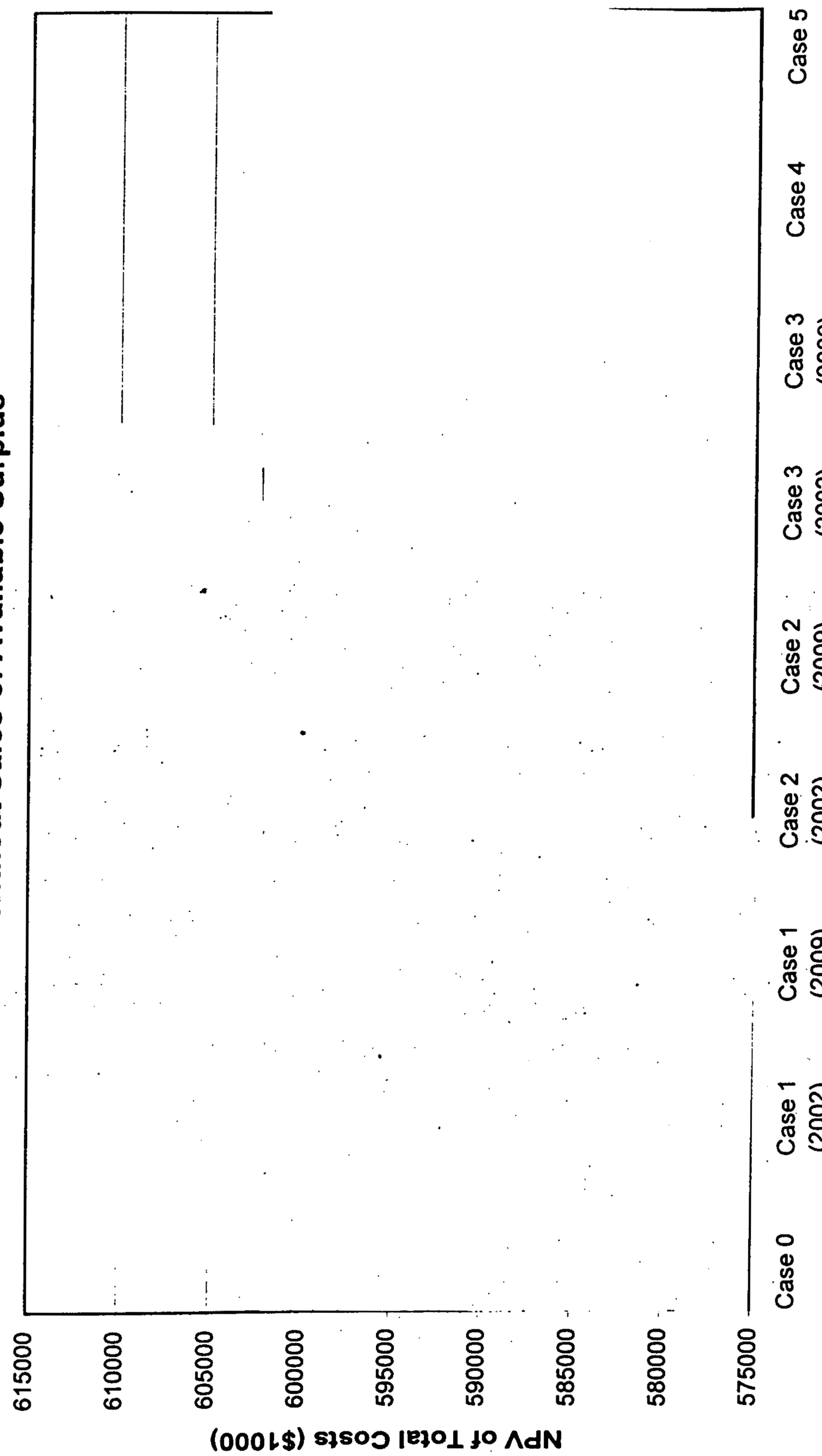
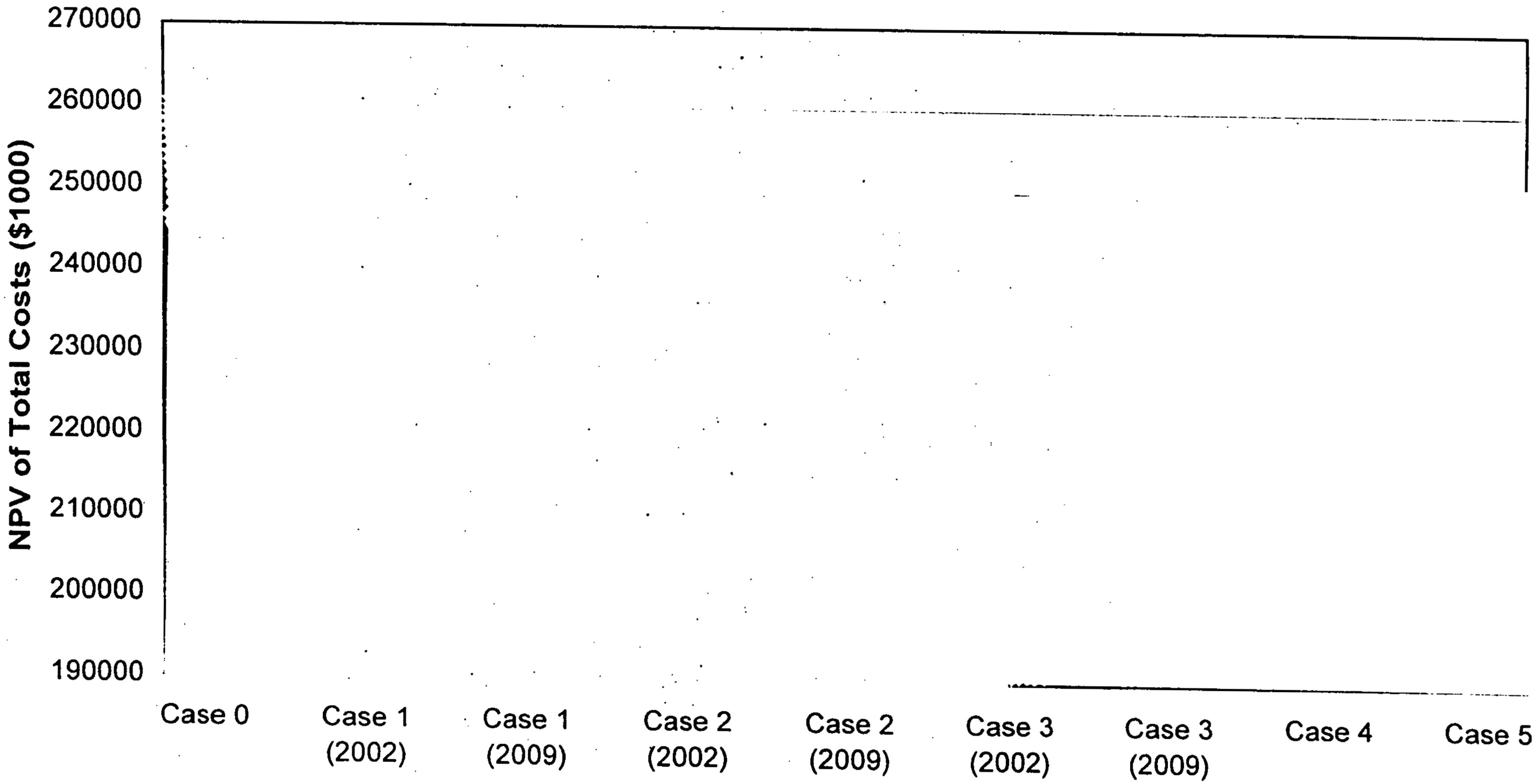


Figure V-2
Comparison of Net Present Value of Total Costs
With Sales of Available Surplus



The projected revenues shown in this chart are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to proces closer to historical levels. The revenues shown in this chart reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

overall revenue for the five cases. The off-system sales scenario presents the potential for revenue generation from the addition of generating resources.

The generation options and purchase of combined cycle unit capacity and energy (Case 3) are not cost effective in meeting Big Rivers native load when compared to the load reduction (Case 5), spot market purchase (Case 0), and peaking purchase options (Case 4). When non-member sales of surplus capacity and energy are considered, the combined cycle option (Case 2) is the most favorable. Cases 2, 3, and 4 were evaluated with capacity being added in both the year 2002 to take advantage of potential spot market sales and in the year 2009 to meet some of the capacity requirements of Big Rivers. Detailed tables of energy sources and costs for each case are included in Appendix D.

The installation of 62 MW of Kenergy's customer's generation has a significant impact on the results of this analysis. If the unit is not installed as expected, the Big Rivers system is projected to become capacity deficient in 2004. In this event Big Rivers must begin planning for its next capacity resource. The impact of this scenario is considered in the risk assessment section of this report.

On all off-system sales, Big Rivers is responsible for the payment of its own Open Access Transmission Tariff (OATT). This payment results in zero cash flow for Big Rivers as a whole and was thus disregarded for the purposes of this analysis.

FINANCIAL INFORMATION (§9)

Projections of total revenue requirements for Big Rivers have been prepared based on the results of the production cost modeling and the financial forecast of Big Rivers. Tables V-3 and V-4 display the nominal revenue requirements for Big Rivers over the 15-year study period without and with the non-member sales. Tables V-5 and V-6 shows the same information on a $/MWh basis. Finally, Tables V-7 and V-8 display the revenue requirements in real (constant) dollars without the impact of inflation.

The revenue requirements included in Tables V-3 through V-7 do not include the potential proceeds of the defeased sale/leaseback arrangement with LEM. Big Rivers recognizes the possibility that this arrangement may proceed to fruition but chooses not to include the proceeds in the revenue requirements because of the uncertainty. This uncertainty will not have any material impact on the outcome of the integrated resource plan.

Table V-3

TOTAL REVENUE REQUIREMENTS FOR ALL CASES WITHOUT SALES OF SURPLUS CAPACITY AND ENERGY

Big Rivers Electric Corporation

Year	*Case 0*	*Case 1* 2002	*Case 1* 2009	*Case 2* 2002	*Case 2* 2009	*Case 3* 2002	*Case 3* 2009	*Case 4*	*Case 5:*
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

Table V-4

TOTAL REVENUE REQUIREMENTS FOR ALL CASES WITH SALES OF SURPLUS CAPACITY AND ENERGY
Big Rivers Electric Corporation

	Case 0	*Case 1*		*Case 2*		*Case 3*		*Case 4*	*Case 5:*
Year		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

The projected revenues reflected in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues reflected in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Table V-5

TOTAL REVENUE REQUIREMENTS FOR ALL CASES WITHOUT SALES OF SURPLUS CAPACITY AND ENERGY ($/MWh)

Big Rivers Electric Corporation

Year	*Case 0*	*Case 1* 2002	*Case 1* 2009	*Case 2* 2002	*Case 2* 2009	*Case 3* 2002	*Case 3* 2009	*Case 4*	*Case 5:*
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

Table V-6

TOTAL REVENUE REQUIREMENTS FOR ALL CASES WITH SALES OF SURPLUS CAPACITY AND ENERGY ($/MWh)
Big Rivers Electric Corporation

Year	Case 0	Case 1 2002	Case 1 2009	Case 2 2002	Case 2 2009	Case 3 2002	Case 3 2009	Case 4	Case 5:
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

The projected revenues reflected in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues reflected in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Table V-7

TOTAL REVENUE REQUIREMENTS IN REAL (CONSTANT) DOLLARS WITHOUT SALES OF SURPLUS CAPACITY AND ENERGY

Big Rivers Electric Corporation

Year	Case 0	Case 1		Case 2		Case 3		Case 4	Case 5
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program

Table V-8

TOTAL REVENUE REQUIREMENTS IN REAL (CONSTANT) DOLLARS WITH SALES OF SURPLUS CAPACITY AND ENERGY

Big Rivers Electric Corporation

Year	Case 0	Case 1		Case 2		Case 3		Case 4	Case 5:
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program

The projected revenues reflected in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues reflected in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Another uncertainty that is not accounted for in the financial forecast is potential capital expenditures for NO_X emission reductions at the Big Rivers power plants. Any capital expenditures must be approved by both Big Rivers and West Kentucky Energy. However, if the improvements are part of a mandatory compliance strategy Big Rivers would have no choice but to pay for a portion of the capital costs. These potential costs were not included in the forecast due to the tremendous uncertainty in their timing and magnitude. The recently proposed purchase of LG&E by PowerGen plc adds to the overall uncertainty of the situation.

The next section of the report provides some indication of the variances in the cases due to change of certain assumptions used in modeling the resources additions.

* * * * *

Part VI

Risk Assessment

PART VI
RISK ASSESSMENT (§8 (1))

The risk assessment performed for Big Rivers analyzed the sensitivity of the best cases described in Part V to the non-installation of 62 MW of member customer generation, an increase and decrease in the projected market energy costs, and the increase in the price of natural gas. This section describes the scenarios that were examined and the results of the risk assessment.

NO CUSTOMER GENERATION SCENARIO

There is a small amount of uncertainty regarding the installation of 62 MW of Kenergy's customer's generation. Because of this uncertainty, a scenario was created to evaluate the impact of the generation not going online in the spring of 2001 as expected. Tables VI-1 and VI-2 show the significant economic impacts of this possibility when compared to Tables V-1 and V-2 including the 62 MW of generation. Overall costs to Big Rivers are significantly higher without the 62 MW of generation because of the need to meet greater demand and energy requirements.

Though overall costs are higher, the ranking of options is not changed from the production cost modeling summarized in Part V including Kenergy's customer's generation. The relative NPVs of the cases are shown in Figures VI-1 and VI-2. The commercial/industrial load management rate program remains the lowest cost alternative when not considering non-member sales. The installation of a 53 MW combined cycle unit in 2002 still provides the greatest opportunity for off-system sales and is therefore the best option when sales are considered.

LOW MARKET ENERGY COST SCENARIO

The addition of merchant combined cycle units as discussed in Parts II and III could potentially reduce the cost of spot market energy. In this scenario the cost of spot market energy was reduced by 20% in the year 2001 corresponding with the commercial operation dates of several new units in the region. The 20% reduction reflects a significant, but not unreasonable, spot market price impact based on the additional supply of spot market energy from merchant power plants. This reduction in spot market cost could have significant implications for Big Rivers as shown in Tables VI-3 and VI-4 and Figures VI-1 and VI-2.

One consideration for Big Rivers regards the sale of the available surplus from the LEM and SEPA contracts. The reduction in revenues from these sales is reflected in the total costs of power supply

Table VI-1

COST SUMMARY TABLE FOR ALL CASES WITHOUT SALES OF SURPLUS CAPACITY AND ENERGY - 62 MW SCENARIO

Big Rivers Electric Corporation

Year	*Case 0*	*Case 1*		*Case 2*		*Case 3*		*Case 4*	*Case 5:*
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program

Table VI-2

COST SUMMARY TABLE FOR ALL CASES WITH SALES OF SURPLUS CAPACITY AND ENERGY - 62 MW SCENARIO

Big Rivers Electric Corporation

Year	*Case 0*	*Case 1* 2002	*Case 1* 2009	*Case 2* 2002	*Case 2* 2009	*Case 3* 2002	*Case 3* 2009	*Case 4*	*Case 5:*
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Table VI-3

COST SUMMARY TABLE FOR ALL CASES WITHOUT SALES OF SURPLUS CAPACITY AND ENERGY - LOW MARKET ENERGY PRICE SCENARIO

Big Rivers Electric Corporation

Year	*Case 0*	*Case 1*		*Case 2*		*Case 3*		*Case 4*	*Case 5:*
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program

Table VI-4

COST SUMMARY TABLE FOR ALL CASES WITH SALES OF SURPLUS CAPACITY AND ENERGY - LOW MARKET ENERGY PRICE SCENARIO

Big Rivers Electric Corporation

Year	Case 0	Case 1 2002	Case 1 2009	Case 2 2002	Case 2 2009	Case 3 2002	Case 3 2009	Case 4	Case 5:
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

compared with the base case in Tables V-1 and V-2. As can be seen from the comparison of these tables, the spot market price reduction would need to be significantly more than 20% to change the results of the analysis.

The choice of options is not changed from the base case including the higher spot market costs. The commercial/industrial load management rate program remains the lowest cost alternative when not considering non-member sales and the installation of a 53 MW combined cycle unit in 2002 still provides the greatest opportunity for off-system sales and is therefore the best option when sales are considered.

This scenario shows the risk involved in depending on spot market sales for revenue. The decrease of 20% in spot market prices has a dramatic impact on the revenue generated by Big Rivers through off-system sales. The volatility of the electricity spot market, as seen in the last two summers, makes a 20% reduction in price from last year's prices a realistic possibility if the additions of merchant generation proceed as planned.

HIGH NATURAL GAS PRICE SCENARIO

The high natural gas price scenario reflects the impact of a ten percent increase in natural gas prices in the year 2001. The time frame was chosen to reflect the significantly increased demand for natural gas that will accompany the operation of new gas-fired combustion turbines and combined cycle units scheduled for operation in the next few years. The 10% gas price increase reflects a significant, but not unreasonable, price impact based on the additional demand for natural gas from merchant power plants.

This case showed only a minor impact on the total costs to Big Rivers because of the small portion of Big Rivers' energy and spot market sales that could result from gas-fired generating resources. The choice of options does not change as a result of a 10% increase in natural gas prices and would not change until the price of gas increased by substantially more than 10%. The economic results of this scenario are shown in Tables VI-5 and VI-6 and Figures VI-1 and VI-2.

RESULTS

In general, the no customer generation scenario has the most significant affect on the cases analyzed because of the significant increase in demand and energy requirements beginning in the year 2001. However, even this impact does not change the overall recommendations resulting from the base case analysis.

* * * * *

Table VI-5

COST SUMMARY TABLE FOR ALL CASES WITHOUT SALES OF SURPLUS CAPACITY AND ENERGY - HIGH GAS PRICE SCENARIO

Big Rivers Electric Corporation

Year	*Case 0*	*Case 1*		*Case 2*		*Case 3*		*Case 4*	*Case 5:*
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program

Table VI-6

COST SUMMARY TABLE FOR ALL CASES WITH SALES OF SURPLUS CAPACITY AND ENERGY - HIGH GAS PRICE SCENARIO

Year	Case 0	Case 1		Case 2		Case 3		Case 4	Case 5:
		2002	2009	2002	2009	2002	2009		
1999									
2000									
2001									
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
NPV									
% Above Min. Case									

Notes:
Case 0: All unmet energy requirements purchased on spot market
Case 1: Installation of 45 MW CT in 2002 or 2009
Case 2: Installation of 53 MW CC unit in 2002 or 2009
Case 3: 50 MW purchase from CC unit in 2002 or 2009
Case 4: Peaking capacity and energy purchases
Case 5: Commercial/Industrial Load Management Program
NPV = Net Present Value of Costs using a 10% discount rate

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Figure VI-1
Comparison of Net Present Value of Total Costs
Without Sales of Available Surplus

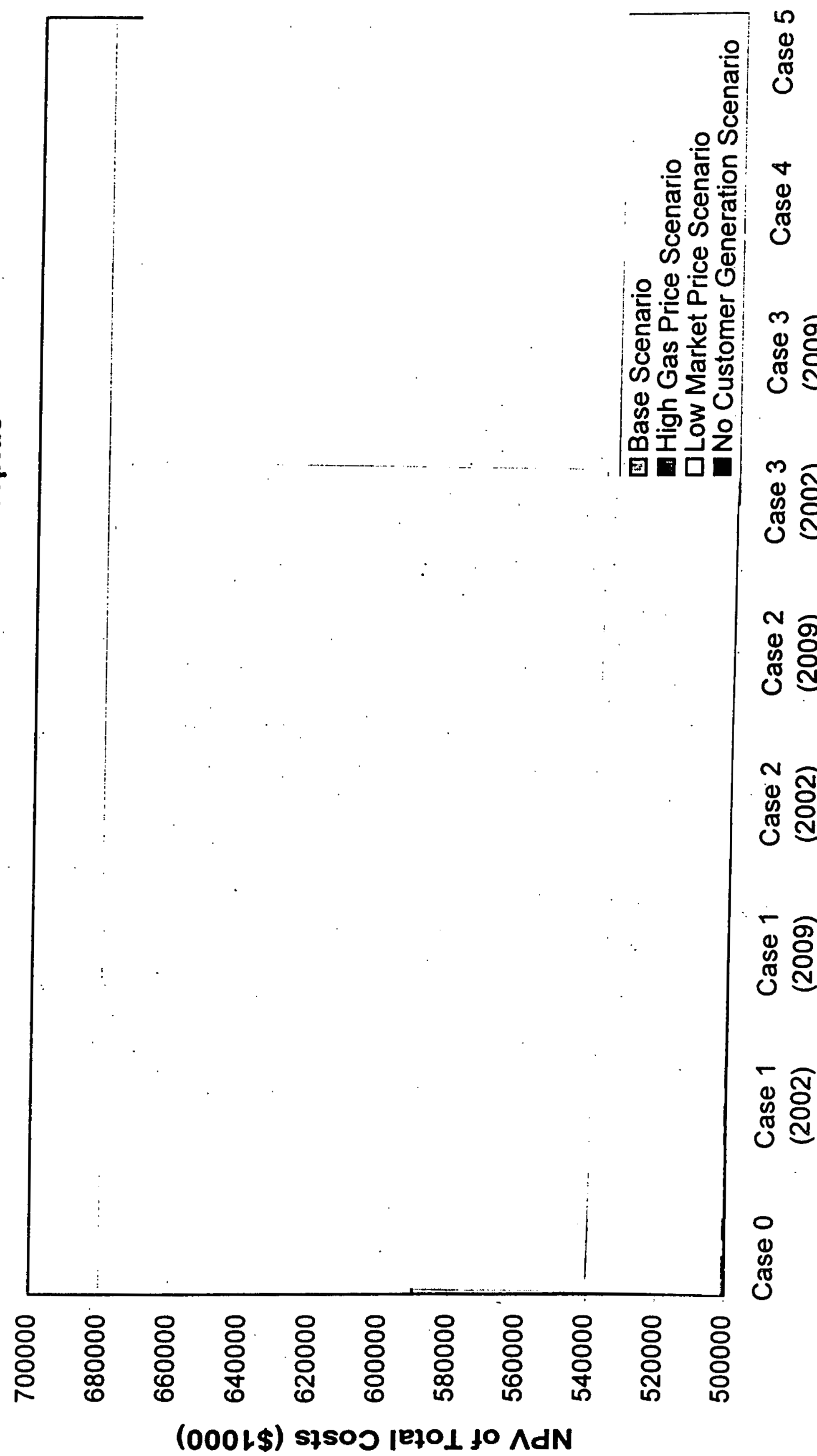
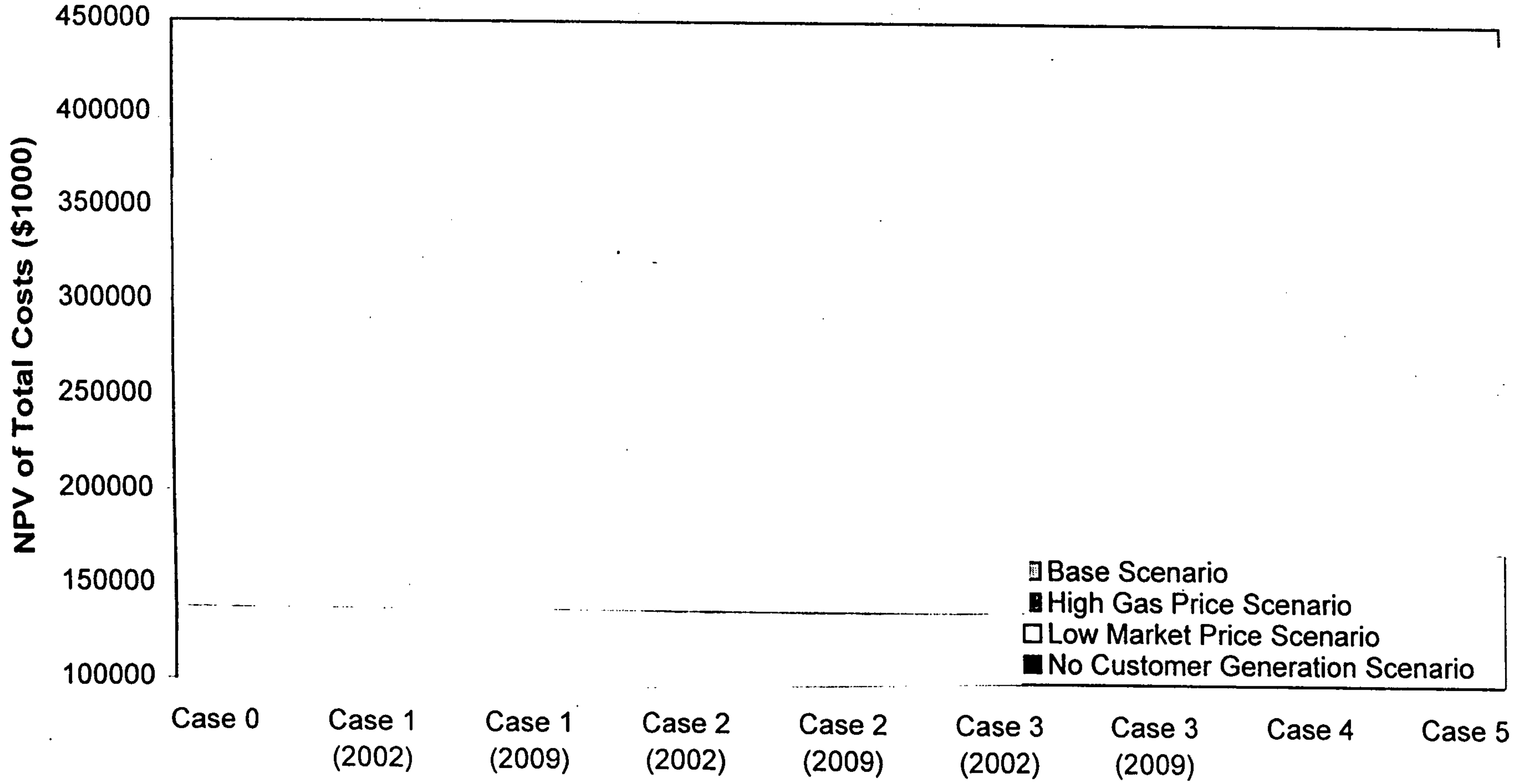


Figure VI-2
Comparison of Net Present Value of Total Costs With Sales of Available Surplus



The projected revenues reflected in this chart are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to proces closer to historical levels. The revenues reflected in this chart reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Part VII

Conclusions and Three-Year Plan

PART VII
CONCLUSIONS AND THREE-YEAR PLAN

CONCLUSIONS

Based on the results of the IRP study, Burns & McDonnell offers the following conclusions:

1. Electric load growth on Big River's system is expected to slow in the next fifteen years compared to the past five years. Not including the aluminum smelter load, average annual energy growth is projected at 2.6% over the next fifteen years (versus historical growth of 6.8% since 1994) and average annual growth in peak demand is projected at 2.4% percent (versus historical growth of 6.7% since 1994). Average annual energy growth is projected to be 1.8% and average annual growth in peak demand is projected at 1.7% percent when including the aluminum smelter loads for transmission and distribution purposes. Although this level of growth is less than recent historical growth rates, it is similar to long-term historical growth rates for Big Rivers. The recent historical growth rates are higher in the PRS because of abnormal demand and energy requirements in 1994.

2. The installation of 62 MW of Kenergy's customer's generation has the most significant impact on future operating conditions for Big Rivers. If the unit is installed as expected, the Big Rivers system will likely not become capacity deficient until the year 2008. Big Rivers will become capacity deficient in 2004 if the unit is not installed and Kenergy's customer continues to purchase all of its power requirements.

   Another uncertainty on Big Rivers' future operating conditions is the potential modification or termination of Big Rivers' contract with the Southeastern Power Administration. Big Rivers depends on the SEPA contract to meet its peak demand throughout the study period. At the current time there is no pending legislation which would alter the SEPA contract. However, there has been discussion by Congress of changing the current mode of operation of the Power Marketing Administrations.

3. The risk analysis quantified the effects of several key uncertainties facing Big Rivers. The no customer generation scenario quantified the impacts of Big Rivers depending on Kenergy's customer's generation to meet load requirements. The high and low market energy cost scenarios quantified the risks and rewards of relying on the short-term spot market for energy purchases versus relying on a specific group of resources for energy.

In general, the no customer generation scenario has the most significant affect on the cases analyzed because of the significant increase in demand and energy requirements beginning in the year 2001. However, even this impact does not change the overall recommendations resulting from the base case analysis.

THREE-YEAR PLAN (§8 (1) & §8 (5) (e))

1. Proceed with the development of a contract to formalize the power supply arrangement and determine the installation schedule for 62 MW of Kenergy's customer's generation. If the unit is installed as planned, Big Rivers will have the opportunity to delay the decision on its next resource addition. The addition of 62 MW of Kenergy's customer's generation will postpone when Big Rivers is projected to become capacity deficient from 2004 to 2009. It is Burns & McDonnell's understanding that this unit is expected by Big Rivers to be operational in the spring of 2001.

2. If Kenergy's customer's generation is not installed Big Rivers will then need to immediately begin the decision making process on the acquisition of its next resource to meet peak demand in the years 2004-2011. Without the customer generation Big Rivers' capacity deficiency is projected to peak in 2010 at 118 MW before increases in the capacity of the LEM contract take effect in 2011 and 2012 and eliminate the capacity deficiency. From the results of the customer generation risk assessment it would appear that after the commercial/industrial load management program, combustion turbines and peaking power purchases reflect the most economical method to meet the capacity deficiency and minimize the potential financial risks associated with spot market purchases. This evaluation is based on the annual revenue requirements and 15-year net present values of total revenue requirements shown in Figures I-2 and I-3.

3. Burns & McDonnell recommends that Big Rivers continue its current evaluation of the implementation of a combined commercial/industrial load management plan. The largest portion of this plan should target the member's industrial customers with high coincident demand and should provide an incentive for participation. This incentive can be either an interruptible rate, a shared savings payment or operation under the market-based rate schedule. The plan should be designed to curtail demand at times when the utility is facing extraordinary constraints or unusually high cost for additional capacity. The identification of industrial customers suitable for this program will be an ongoing process that should build upon the current foundation of the program.

This type of program has proven to not only lower peak demand and energy requirements providing for non-member sales during times of high spot market prices but also builds customer satisfaction. By taking a proactive role in keeping its members and their customers satisfied, Big Rivers can help ensure its ongoing success.

4. Big Rivers should encourage the use of distributed generation among its members to lower peak demands and energy requirements and provide Big Rivers with greater flexibility in its power supply operations. The benefits of distributed generation for Big Rivers would be similar to the impacts of the 62 MW of Kenergy's customer's generation evaluated in this study.

   Distributed generation utilizing reciprocating engines, small combustion turbines, and potentially fuel cells, microturbines, and renewable resources is becoming more and more popular for the benefits they can provide both to the customer and the host utility. The analysis of the potential benefits of distributed generation additions is very site specific and must be performed on a case-by-case basis.

5. Big Rivers should maintain an ongoing dialogue with other potential power suppliers regarding low cost energy and capacity sources. Locking in low-cost capacity and energy would further mitigate the risks associated with spot market purchases and the limitations of the SEPA contract in meeting peak demands during the summer. Discussions should also be entered into within the next three years for power to meet requirements in the 2004 to 2011 time frame if necessary.

6. Big Rivers should continue to monitor the progress of state and federal legislation to determine the potential impacts on the operations of the Big Rivers system.

* * * * *

Appendix A

1999 Power Requirements Study

1999 Power Requirements Study

for

Big Rivers Electric Corporation
Henderson, Kentucky
Kentucky 62

1999

99-089-4

BigRivers
Electric Corporation

A Touchstone Energy™ Partner

Burns
&
McDonnell

Burns & McDonnell
SINCE 1898

September 8, 1999

Mr. C. William Blackburn
Vice President of Power Supply
Big Rivers Electric Corporation
201 Third Street
P.O. Box 24
Henderson, KY 42419-0024

Big Rivers Electric Corporation
1999 Power Requirements Study
Project No. 99-089-4

Dear Mr. Blackburn:

Burns & McDonnell is pleased to provide this 1999 Power Requirements Study (PRS) for Big Rivers Electric Corporation. The projections developed in this study were prepared in accordance with current RUS guidelines and are intended for use as a supporting document in loan applications and to provide a basis for engineering and planning studies.

This PRS is based on data for the historical period from 1979 to 1998, from which forecasts for the twenty-year period from 1999 through 2018 were developed. The Big Rivers' energy requirements forecast was developed by summing the individual forecasts developed by Burns & McDonnell for each of Big Rivers' member systems. The individual member forecasts are detailed in the members' PRS reports.

The member cooperatives' long-term and short-term rural energy requirements forecasts were developed using econometric modeling. Long-term peak demand forecasts were developed using the historical relationship between load factor and energy. Trend-seasonal modeling was used to develop short-term peak demand forecasts.

Based on Burns & McDonnell's analyses, Big Rivers' total rural system energy requirements and rural peak demand are both projected to grow at average annual compound growth rates of 3.0 percent from 1998 to 2018. This compares to growth rates of 4.2 percent for total system rural energy requirements and 4.3 percent for rural peak demand over the period 1994 through 1998. These projections of continued growth are driven by a combination of continued increase in the area's population and employment as well as continued growth in the commercial and industrial sectors of Big Rivers' service area.

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690
www.burnsmcd.com

It should be noted that this forecast is based upon the projection of historical relationships between energy sales and various independent or explanatory variables. Because these relationships are intended to reflect general future trends, the projected values for any given year will not necessarily be the actual value that will be experienced in that year. However, it is felt the overall growth rates suggested by the projected values will reflect the growth rates which will be experienced over the long-term based upon the information currently available.

We appreciate the cooperation and assistance given by the Big Rivers staff to Burns & McDonnell in the preparation of this study. We will be happy to discuss this study with you in detail at your convenience.

Sincerely,

David E. Christianson
Vice President
Management Services Group

Deanna C. Korondi

Deanna C. Korondi
Project Manager

TABLE OF CONTENTS

Page No.

TABLE OF CONTENTS
(continued)

LIST OF TABLES

LIST OF FIGURES

* * * * *

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

BIG RIVERS ELECTRIC CORPORATION
POWER REQUIREMENTS STUDY

OVERVIEW

The 1999 Power Requirements Study (PRS) is a twenty-year (1999 to 2018) forecast of energy requirements and peak demand for Big Rivers Electric Corporation (Big Rivers). Big Rivers is a generation and transmission cooperative system located in western Kentucky with headquarters in Henderson, Kentucky. Big Rivers' four member distribution cooperatives serve approximately 96,152 accounts, of which 90 percent are residential. These residential consumers account for 36.4 percent of total energy sales less sales to two large smelters.

Big Rivers provides all or part of the power requirements of the following four member distribution cooperatives:

Member	RUS Designation
Green River Electric Corporation Owensboro, Kentucky	Kentucky 33
Henderson-Union Electric Cooperative Henderson, Kentucky	Kentucky 55
Jackson Purchase Energy Corporation Paducah, Kentucky	Kentucky 20
Meade County Rural Electric Coop. Corp. Brandenburg, Kentucky	Kentucky 18

The long-term and short-term load forecasts for each member cooperative, arrived at primarily using econometric modeling, are based on historical data from 1979 to 1998. These results have been incorporated into a comprehensive Power Requirements Study for the cooperatives' power supplier, Big Rivers. Econometric forecasts developed for this PRS attempt to model the impacts the local economy has had on the cooperatives' historical sales and use them to project future electricity sales and demand. Such factors as population, total employment, and weather conditions were evaluated in the models used.

The PRS was prepared with a "bottom-up" approach to better analyze the disparate variables that affect the individual consumer classes. These individual classes were then summed to arrive at a total energy requirements forecast for Big Rivers.

FORECASTS

Historical and projected total energy requirements by class are summarized in Table ES-1 and depicted graphically in Figure ES-1. Total rural energy requirements, calculated as the sum of the class energy forecasts and losses, are projected to grow approximately 3.0 percent per year from 1998 to 2018. Table ES-1 breaks down the total sales into individual consumer classes for the periods 1998-2003 and 1990-2018. The following are the average annual growth rates forecast for Big Rivers' individual classes for the twenty-year/long-term forecast period and the four-year/short-term period:

Energy Sales	*Average Annual Growth Rate 1998-2003*	*Average Annual Growth Rate 1998-2018*
Residential Consumers	2.3%	1.9%
Total Residential Energy Sales	3.6%	3.1%
Small Commercial Consumers	2.5%	2.0%
Total Small Commercial Energy Sales	3.7%	2.8%
Large Commercial Consumers	2.1%	1.0%
Total Large Commercial Energy Sales	3.5%	1.1%
Public Street & Highway Lighting Consumers	1.6%	1.5%
Total Public Street & Highway Lighting Sales	2.6%	2.4%
Total Rural Energy Sales	3.6%	1.5%
Smelter Sales	3.0%	0.7%
Total Non-Rural Energy Sales	3.4%	1.0%
Total Rural Energy Requirements	4.2%	3.0%
Total System Energy Requirements	3.5%	1.5%

PEAK DEMAND AND LOAD FACTOR

The long-term peak demand forecast for Big Rivers was developed using an econometric model and the short-term demand model was developed using a seasonal-index model. Table ES-2 and Figure ES-2 display the coincident peak demand forecast for the rural system and the non-coincident peak demand forecast for the total system. As shown, rural coincident peak demand is expected to increase to approximately 765.0 MW by 2018, an average annual increase of 3.0

Table ES-1
Energy Forecasts

Energy Sales Forecasts By Consumer Class (MWh)	Long-Term 2018	Short-Term 2002
Residential	2,196,184	1,512,782
Small Commercial	739,515	502,491
Large Commercial (Rural)	210,052	121,008
Large Commercial (Non-Rural)	8,062,230	7,772,274
Public Street and Highway	4,596	4,102
Total Rural Energy Requirements [1]	3,339,218	2,179,802
Total System Energy Requirements	11,401,449	9,952,076

[1] The sum of individual short-term consumer forecasts does not equal Total Rural Energy Requirements because Consumer Class Sales Forecast does not include an estimated 6.28 percent in Own Use and Losses. This percentage is estimated based on 1998 difference between Total kWh Purchased and Total kWh Sold

Figure ES-1
Big Rivers' Energy Requirements

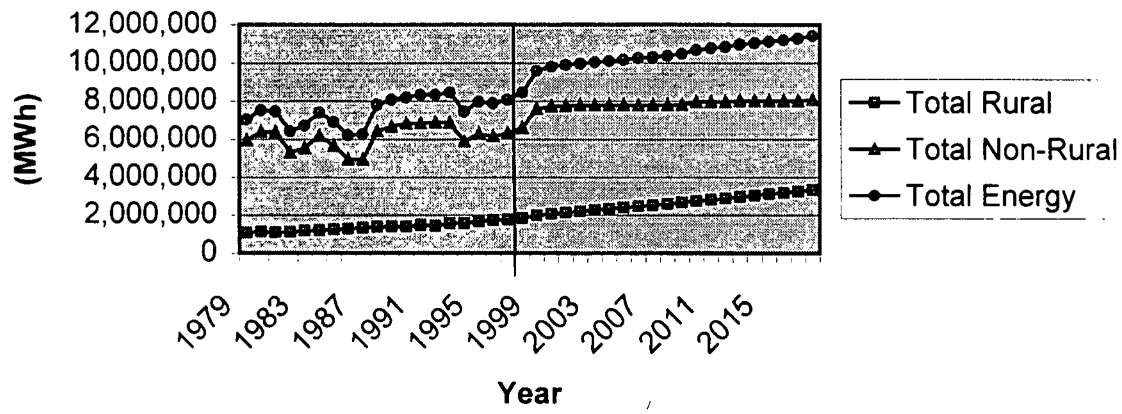
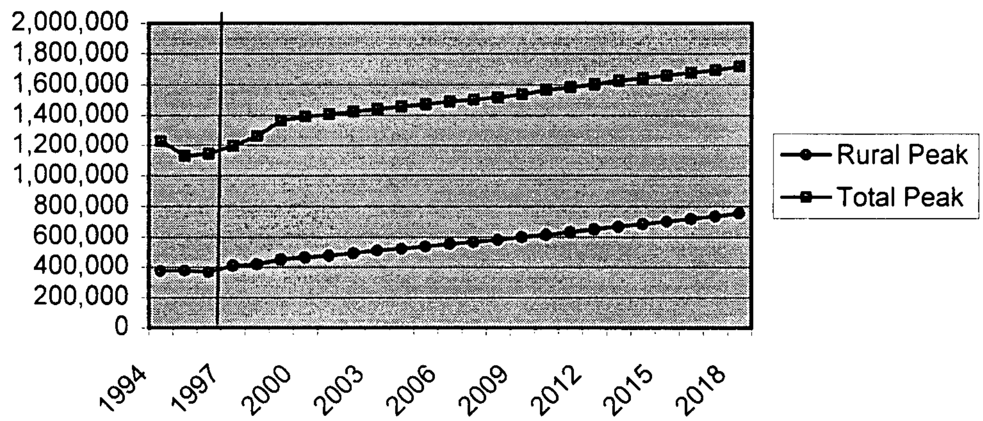


Table ES-2
Demand Forecasts

Demand Forecasts kW	Long-Term 2018	Short-Term 2002
Rural Peak Demand	764,991	487,530
Total System Demand	1,728,618	1,420,758

Figure ES-2
Rural and Total System Demand



percent over the forecast period. As shown, total system non-coincident peak demand is expected to increase to approximately 1,728.6 MW by 2018; an average annual increase of 1.6 percent over the forecast period.

Coincident and Non-coincident Demand	*Long-Term Annual Growth Rate 1998-2018*	*Short-Term Annual Growth Rate 1998-2002*
Coincident Peak Demand (Rural)	3.0%	3.5%
Non-Coincident Peak Demand (Rural)	3.0%	3.9%
Non-Coincident Peak Demand (Total System)	1.6%	2.7%

COMPARISON WITH OTHER FORECASTS

The Energy Information Administration (EIA) has forecast total United States net energy for load to grow at 1.4 percent per year through 2020 (Annual Energy Outlook 1998). The administration also predicts that the prime drivers of overall U.S. electricity sales growth will be the residential class at 1.5 percent per year, most of which (87 percent) will be due to an increased use of electricity. This of particular interest due to the cooperative's large residential consumer classification. The commercial and industrial sectors are projected to have lower annual growth rates of 1.2 and 1.3 percent per year, respectively, through 2020.

UNCERTAINTY ANALYSES

Uncertainty analyses were performed to estimate the impact of varying conditions on the cooperative's rural load growth. Weather assumptions, economic conditions, and electricity prices were varied from the historical norms used in the base case projections. The uncertainty analyses were completed based on rural sales, and therefore did not include non-rural sales.

Figure ES-3 indicates that electricity sales are expected to be much more dependent on future economic conditions than year-to-year weather variation. Conversely, Figure ES-4 indicates that a high level of year-to-year variation in peak demand is the result of variance in weather conditions. The variation in peak demand due to economic conditions was developed by applying the base case load factor to the optimistic and pessimistic energy requirements scenarios, these show nearly as much variation as the weather scenarios.

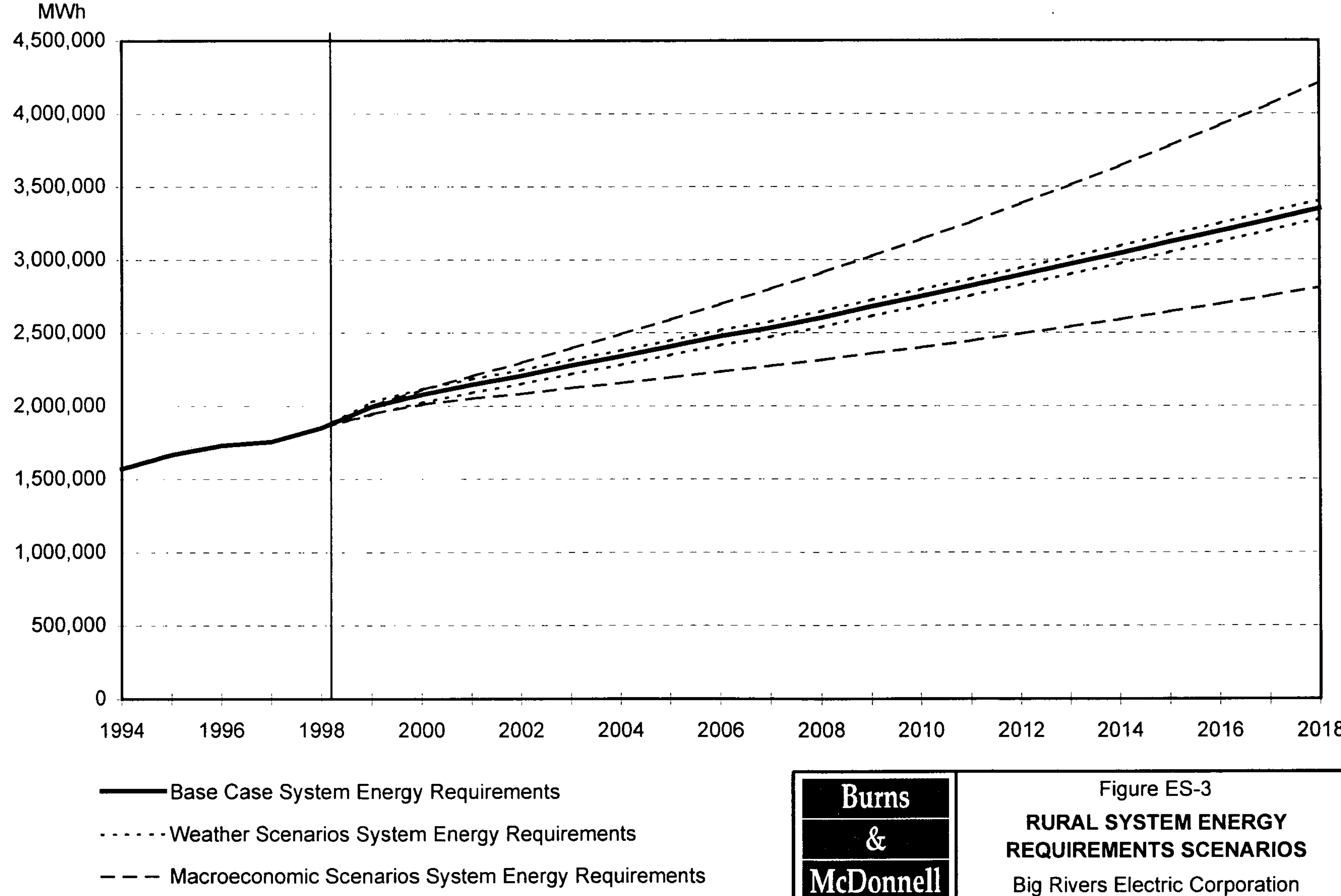
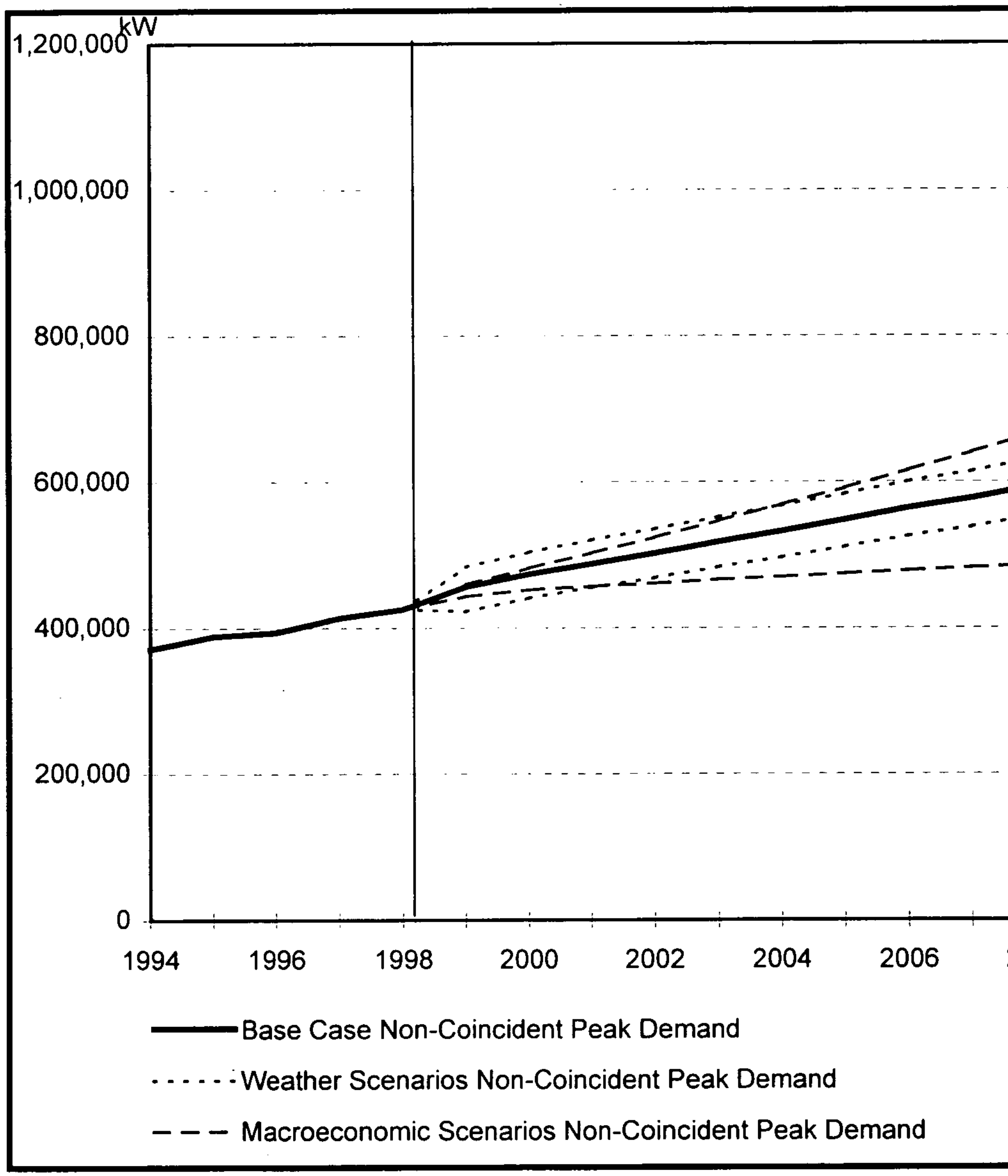


Figure ES-3

RURAL SYSTEM ENERGY REQUIREMENTS SCENARIOS

Big Rivers Electric Corporation



Burns & McDonnell

Figure ES-4
RURAL SYSTEM DEMAND SCENARIOS
Big Rivers Electric Corporation

The optimistic economic scenario forecast projects that total energy requirements will reach 4,210,797 MWh by 2018 and peak demand will reach 966.4 MW. The pessimistic economic scenario forecast projects that total energy requirements will reach only approximately 2,808,213 MWh by 2018 and peak demand will reach 523.9 MW.

*****

PART I – INTRODUCTION

PART I

INTRODUCTION

THE 1999 PRS

The 1999 Power Requirements Study (PRS) is a twenty-year (1999 to 2018) forecast of energy requirements and seasonal peak demand for Big Rivers Electric Corporation (Big Rivers).

This study represents an aggregation of the forecasts prepared for each of these members. The study will serve as the foundation of Big Rivers' operations and planning activities, which include the following:

- Resource development
- Financial analysis
- Rate design and development
- Marketing
- Demand-side management
- Load control
- Consumer services planning

This PRS has been prepared in accordance with current RUS guidelines. Details of the specific methodologies employed in the development of this PRS can be found in the 1999 Power Requirements Study Work Plan for Big Rivers (Work Plan). The Work Plan was developed jointly among Big Rivers, its members and Burns and McDonnell and has been approved by Big Rivers' Board of Directors and the RUS's Energy Forecasting Branch.

Big Rivers' intends for this document to be part of a series of ongoing reviews of the demand, energy and consumer requirements of the system.

BACKGROUND

The Cooperative

Big Rivers is a generation and transmission cooperative headquartered in Henderson, Kentucky. Big Rivers provides all or part of the power requirements of the following four member distribution cooperatives with service territories in western and northwestern Kentucky:

Member	RUS Designation
Green River Electric Corporation Owensboro, Kentucky	Kentucky 33
Henderson-Union Electric Cooperative Henderson, Kentucky	Kentucky 55
Jackson-Purchase Electric Cooperative Energy Corporation Paducah, Kentucky	Kentucky 20
Meade County Rural Electric Cooperative Corporation Brandenburg, Kentucky	Kentucky 18

These distribution cooperatives serve primarily residential consumers, with 80,121 residential consumers or 89.4 percent of total consumers. In addition, sales for two of Big Rivers's members, Jackson Purchase and Meade County, are primarily residential. Big Rivers currently provides power to its members through seventy-one rural substations as well as twenty-five dedicated metering points. Power is delivered based on a tariff that became effective July 18, 1998.

Geography and Climate

Geography and climate of the service area can be responsible for much of the year-to-year variation in a utility's energy sales and peak demand. Although future weather conditions cannot be forecast more than a few days ahead, historical weather data are used in explanatory equations to account for fluctuations in historical electricity sales caused by abnormal weather conditions.

The topography of the Big Rivers members' service areas range from nearly level along the Ohio River to moderately hilly in the upland areas. Typical elevations range from approximately 400 to 1,000 feet above sea level.

The climate in the area is humid, temperate and continental. Daily and seasonal changes in temperature, cloudiness, wind and precipitation may be sudden and extreme. The seasons are well defined, but changes between the seasons are gradual. The weather statistics from the Evansville and Paducah weather stations were used for the econometric analysis in this study.

Economic & Demographic Factors

In addition to the effects of the local geography and climate on sales, electricity sales in the United States generally track the economy. The strong correlation between the total U.S. electricity sales and GDP has been well documented. However, the factors which are most important to the Big Rivers'-area economy are not the same factors which drive the overall U.S. economy. Therefore, a detailed analysis of the members' local economies was conducted as part of this PRS. Economic and demographic factors affecting electricity sales within the service area may include electricity prices, alternate fuel prices, the population and employment of the service area and income – both total personal and per capita income relative to the service area.

An extensive data base of county-level data was obtained for this study. To better represent the members' service areas, these data were weighted based on member cooperatives' estimated market shares in the various counties they serve. Such factors as population, total employment, sector employment, the level of real (inflation-adjusted) total personal income, real per capital income, real electricity prices, real alternative fuel prices, and weather conditions were evaluated in the econometric equations developed for this PRS. Refer to Appendix A for a listing of the data sources used in this PRS.

Forecasting Techniques Used in this PRS

The 1999 PRS is based on historical data from the period 1970 through 1998, from which forecasts for the period 1999 through 2018 were developed. A variety of forecasting techniques were used in order to develop the forecast of Big Rivers' energy requirements and peak demand. Econometric modeling was the primary forecasting technique used to quantify relationships between energy and economic, demographic and system trends. The basic premise of econometric forecasting is that the historical relationship between energy sales and various influencing factors will continue. The econometric forecasts developed for this PRS attempt to capture the impact of the local economy on the cooperatives' sales. Refer to the distribution member cooperative reports for a detailed discussion of the specific models developed.

Other methods including judgment and discussions with the member cooperatives and Big Rivers were also employed when necessary to enhance the modeling or to replace it where models were not practical. The extensive knowledge that Big Rivers and the member cooperatives have of the service areas enhanced the formal forecasting approaches. Ongoing discussions among Big Rivers, the member cooperatives and Burns & McDonnell were carried out to ensure that this

PRS incorporates the best and most current information available. Adjustments were made, as necessary, to account for known changes to significant loads.

The long-term forecasts for the period 1999 to 2018, shown in Part II, were developed based on historical data from 1979 to 1998. Short-term forecasts, also shown in Part II, were developed to project the total energy requirements and system coincident peak demand monthly through 2002. Part III of this study presents a range of long-term forecasts based on different assumptions about the future. Uncertainty analyses were performed to estimate the impact of varying conditions on the cooperative's load growth.

A listing of the data sources used in the forecasting, RUS Form 341, the adjustments made to the Form 7 data for the modeling process and the database of input assumptions are included in the appendices.

* * * * *

PART II - FORECASTS

PART II

FORECASTS

FACTORS CONSIDERED IN ECONOMIC FORECASTING

The basic premise of econometric forecasting is that the historical relationship between energy sales and economic and demographic factors will continue into the future. Thus, the underlying hypothesis of this study is that Big Rivers' future energy sales growth, in general, is likely to be determined by the same factors that have influenced growth in the past. Factors including population, total employment, the level of real (inflation-adjusted) total personal income, real per capita income, real electricity prices, and real alternative fuel prices were considered. The forecasts of consumers and electricity sales were developed based on the factors identified which affect the following consumer classes of the cooperative's system:

- Number of residential consumers
- Residential energy sales per consumer
- Total residential energy sales
- Number of small commercial consumers
- Small commercial energy sales per consumer
- Total small commercial energy sales
- Number of large commercial consumers
- Total large commercial energy sales
- Other consumers
- Other energy sales

Climate: Projected Weather Data

The effects weather has on consumer spending for electricity is in the form of heating and cooling costs during the various seasons of the year. Table II-1 displays twenty-nine years of annual historical data from the Evansville, Indiana weather station and fourteen years of annual historical data from the Paducah, Kentucky weather station. The twenty-year projections are based on the historical averages. Included in the table are both heating degree days and cooling degree days for the calendar year. A heating degree day is an indicator of heating requirements based on the difference between 65 degrees Fahrenheit and the average daily temperature. Likewise, a cooling degree day is an indicator of cooling requirements based on the difference between the average

Table II-1

HISTORICAL AND PROJECTED WEATHER DATA [1]
Big Rivers Electric Corporation

		Calendar Year Data [1]			Calendar Year Data [2]		
	Year	Heating Degree Days	Cooling Degree Days	Total Degree Days	Heating Degree Days	Cooling Degree Days	Total Degree Days
	1970	4,893	1,396	6,289			
	1971	4,428	1,566	5,994			
	1972	4,909	1,160	6,069			
	1973	4,188	1,567	5,755			
	1974	4,172	1,229	5,401			
	1975	4,283	1,500	5,783			
	1976	4,784	1,112	5,896			
	1977	4,799	1,779	6,578			
	1978	5,420	1,550	6,970			
	1979	5,227	1,238	6,465			
	1980	5,095	1,726	6,821			
	1981	4,548	1,389	5,937			
	1982	4,399	1,349	5,748			
	1983	4,640	1,664	6,304			
	1984	4,622	1,365	5,987			
	1985	4,785	1,445	6,230	4,480	1,439	5,919
	1986	4,386	1,576	5,962	3,946	1,734	5,680
	1987	4,290	1,623	5,913	3,868	1,841	5,709
	1988	4,822	1,500	6,322	4,398	1,658	6,056
	1989	4,830	1,396	6,226	4,443	1,492	5,935
	1990	3,856	1,380	5,236	3,460	1,557	5,017
	1991	4,253	1,757	6,010	3,713	1,965	5,678
	1992	4,217	1,240	5,457	3,524	1,382	4,906
	1993	4,652	1,613	6,265	4,231	1,686	5,917
	1994	4,180	1,489	5,669	3,911	1,409	5,320
	1995	4,314	1,773	6,087	4,129	1,615	5,744
	1996	5,068	1,224	6,292	4,573	1,390	5,963
	1997	4,901	1,119	6,020	4,445	1,271	5,716
Historical	1998	3,863	1,629	5,492	3,535	1,798	5,333
Projected	1999	4,580 [3]	1,460 [3]	6,041	4,047 [4]	1,588 [4]	5,635
	2000	4,580	1,460	6,041	4,047	1,588	5,635
	2001	4,580	1,460	6,041	4,047	1,588	5,635
	2002	4,580	1,460	6,041	4,047	1,588	5,635
	2003	4,580	1,460	6,041	4,047	1,588	5,635
	2004	4,580	1,460	6,041	4,047	1,588	5,635
	2005	4,580	1,460	6,041	4,047	1,588	5,635
	2006	4,580	1,460	6,041	4,047	1,588	5,635
	2007	4,580	1,460	6,041	4,047	1,588	5,635
	2008	4,580	1,460	6,041	4,047	1,588	5,635
	2009	4,580	1,460	6,041	4,047	1,588	5,635
	2010	4,580	1,460	6,041	4,047	1,588	5,635
	2011	4,580	1,460	6,041	4,047	1,588	5,635
	2012	4,580	1,460	6,041	4,047	1,588	5,635
	2013	4,580	1,460	6,041	4,047	1,588	5,635
	2014	4,580	1,460	6,041	4,047	1,588	5,635
	2015	4,580	1,460	6,041	4,047	1,588	5,635
	2016	4,580	1,460	6,041	4,047	1,588	5,635
	2017	4,580	1,460	6,041	4,047	1,588	5,635
	2018	4,580	1,460	6,041	4,047	1,588	5,635

[1] Weather data provided by Big Rivers for the Evansville, Indiana weather station.
[2] Weather data provided by Jackson Purchase for the Paducah, Kentucky weather station.
[3] Twenty-nine year average.
[4] Fourteen year average.

daily temperature and 65 degrees Fahrenheit. These indicators are more often used in econometric modeling of energy usage than is temperature.

Economic & Demographic Projections

Population. A change in the number on residential consumers due to a change in population can account for a large portion of change in the system load. Population growth in Big Rivers' member service territories has generally been similar to the population growth rates of the U.S. and the State of Kentucky. See Table II-2 for the historical and projected total population figures as given by the *Woods & Poole* for the Big Rivers' service area. Since 1993, the area has had population growth averaging 0.8 percent annually. According to *Woods & Poole* figures, during the 1993 to 1998 period the State of Kentucky and the U.S. had annual population growth rates of 0.8 percent and 0.9 percent respectively. Total population forecast for Big Rivers' service territory is projected to grow steadily at 0.6 percent per year through 2018.

Employment. Growth in employment typically has a significant impact on energy sales in the residential and small commercial classes. Total employment in Big Rivers' service area has grown steadily over the past fifteen years, as shown in Table II-2, and is projected to increase during the next twenty years as well. The average annual compound growth rate from 1993 through 1998 was 1.9 percent. In 1999, total employment is estimated to be 104,480 which is up 1.1 percent from 1998. The projected growth rate from 1998 to 2018 is 0.9 percent annually.

Income. A factor which has a direct impact on consumer spending, including electricity purchases, is the level of real (inflation-adjusted) personal income. In addition to total personal income, per capita income was evaluated for its historical relationship to the number of consumers and electricity sales. Historical weighted *Woods and Poole* income data is shown in Table II-2. Per capita income (total personal income divided by total population) measures the average income of the persons in the area under study. As shown in Table II-2, the per capita income is projected to grow 1.2 percent annually from 1998 to 2018.

Real Electricity Prices. Historical and projected electricity prices for the residential and small commercial classes were developed based on projected wholesale prices to the members from Big Rivers and historical retail markups for the member systems. Real electricity prices, figured in 1992 dollars, are forecast to steadily decline for the residential and commercial classes for each of the member systems. Refer to the member reports for specific price projections.

Table II-2

HISTORICAL AND PROJECTED ECONOMIC & DEMOGRAPHIC DATA
Big Rivers Electric Corporation

		Big Rivers			Kentucky In (1,000's)		Kentucky 1992$	United States In (1,000's)		United States 1992$
	Year	Total Population	Total Employment	Per capita Income	Total Population	Total Employment	Per capita Income	Total Population	Total Employment	Per capita Income
	1979	196,373	84,785	$ 14,581	3,636	1,668	$ 14,135	224,567	113,288	$ 17,282
	1980	198,600	83,731	$ 14,013	3,665	1,646	$ 13,858	227,226	114,231	$ 17,203
	1981	198,943	83,028	$ 14,408	3,670	1,639	$ 14,135	229,466	115,304	$ 17,486
	1982	198,751	81,352	$ 14,263	3,683	1,620	$ 14,039	231,665	114,521	$ 17,402
	1983	199,768	82,247	$ 13,593	3,694	1,629	$ 13,785	233,793	116,020	$ 17,576
	1984	201,074	84,221	$ 14,905	3,695	1,682	$ 14,832	235,826	121,051	$ 18,578
	1985	200,968	83,666	$ 14,658	3,695	1,706	$ 14,901	237,925	124,473	$ 19,050
	1986	200,435	84,401	$ 14,737	3,688	1,741	$ 15,082	240,134	126,941	$ 19,467
	1987	199,657	84,843	$ 14,962	3,683	1,774	$ 15,402	242,290	130,371	$ 19,750
	1988	198,468	86,340	$ 15,097	3,680	1,828	$ 15,657	244,500	134,676	$ 20,235
	1989	198,747	88,910	$ 15,494	3,677	1,877	$ 16,074	246,820	137,318	$ 20,547
	1990	199,332	90,614	$ 15,558	3,692	1,915	$ 16,258	249,441	139,185	$ 20,652
	1991	199,626	90,334	$ 15,507	3,715	1,916	$ 16,285	252,128	138,786	$ 20,333
	1992	201,262	91,826	$ 15,991	3,752	1,964	$ 16,761	255,004	139,411	$ 20,631
	1993	203,420	93,896	$ 15,960	3,793	2,005	$ 16,860	257,755	142,005	$ 20,814
	1994	204,993	96,362	$ 16,288	3,824	2,049	$ 17,077	260,295	145,650	$ 21,099
	1995	207,205	98,938	$ 16,509	3,856	2,104	$ 17,522	262,761	149,444	$ 21,717
	1996	208,787	100,371	$ 17,040	3,882	2,134	$ 18,016	265,181	152,337	$ 22,267
	1997	210,580	102,067	$ 17,341	3,908	2,180	$ 18,453	267,637	155,711	$ 22,844
Historical	1998	211,981	103,308	$ 17,587	3,937	2,208	$ 18,701	270,051	157,520	$ 23,119
Projected	1999	213,210	104,480	$ 17,839	3,964	2,236	$ 18,959	272,373	159,342	$ 23,404
	2000	214,400	105,605	$ 18,088	3,990	2,263	$ 19,218	274,676	161,178	$ 23,694
	2001	215,594	106,687	$ 18,333	4,016	2,290	$ 19,478	276,963	163,028	$ 23,988
	2002	216,816	107,736	$ 18,571	4,043	2,317	$ 19,737	279,238	164,890	$ 24,285
	2003	217,996	108,773	$ 18,812	4,069	2,344	$ 19,998	281,501	166,766	$ 24,586
	2004	219,146	109,796	$ 19,054	4,095	2,370	$ 20,259	283,765	168,654	$ 24,890
	2005	220,360	110,812	$ 19,291	4,121	2,396	$ 20,520	286,034	170,555	$ 25,196
	2006	221,540	111,817	$ 19,530	4,148	2,423	$ 20,780	288,326	172,469	$ 25,503
	2007	222,778	112,824	$ 19,765	4,175	2,449	$ 21,037	290,644	174,395	$ 25,809
	2008	224,057	113,829	$ 19,996	4,202	2,476	$ 21,295	292,991	176,332	$ 26,116
	2009	225,333	114,826	$ 20,228	4,230	2,502	$ 21,550	295,371	178,282	$ 26,422
	2010	226,623	115,835	$ 20,460	4,258	2,528	$ 21,803	297,783	180,243	$ 26,728
	2011	227,949	116,828	$ 20,689	4,287	2,555	$ 22,055	300,225	182,216	$ 27,033
	2012	229,314	117,832	$ 20,914	4,316	2,581	$ 22,304	302,694	184,200	$ 27,338
	2013	230,698	118,832	$ 21,139	4,345	2,607	$ 22,553	305,179	186,195	$ 27,644
	2014	232,072	119,837	$ 21,365	4,375	2,634	$ 22,800	307,682	188,200	$ 27,951
	2015	233,449	120,836	$ 21,592	4,404	2,660	$ 23,048	310,193	190,216	$ 28,259
	2016	234,850	121,832	$ 21,816	4,434	2,686	$ 23,294	312,712	192,242	$ 28,568
	2017	236,237	122,831	$ 22,043	4,464	2,712	$ 23,540	315,235	194,278	$ 28,879
	2018	237,622	123,829	$ 22,271	4,494	2,738	$ 23,787	317,753	196,324	$ 29,193
Average Annual Compound Growth Rates:										
	1979-1998	0.4%	1.0%	1.0%	0.4%	1.5%	1.5%	1.0%	1.7%	1.5%
	1993-1998	0.8%	1.9%	2.0%	0.8%	2.0%	2.1%	0.9%	2.1%	2.1%
	1998-2003	0.6%	1.0%	1.4%	0.7%	1.2%	1.4%	0.8%	1.1%	1.2%
	1998-2018	0.6%	0.9%	1.2%	0.7%	1.1%	1.2%	0.8%	1.1%	1.2%

Alternative Fuels. Another factor, which may influence electricity sales, is the availability of alternative energy sources. Liquid propane and natural gas have proven to be the largest competitors to electricity in the service area. Timber is another alternative source of heating fuel available in the western portion of the state.

PRESENTATION OF ECONOMETRIC EQUATIONS

The essence of the "bottom-up" approach to the 1999 PRS for Big Rivers was the realization that there is no one typical member cooperative. Before being able to forecast the energy requirements for Big Rivers' system, the factors that most influence electricity sales for each particular cooperative needed to be identified. Only after determining the power requirements of each individual cooperative could Big Rivers' aggregate forecast be developed.

Similarly, the bottom-up approach to the 1999 PRS for each of Big Rivers member distribution cooperatives recognized that there is no typical consumer class. Therefore, sales forecasts for each individual consumer class were developed to arrive at the system-wide forecast of each members' total power requirements.

This part of the report presents the aggregated results of the forecasts of consumers and electricity sales by consumer class that were developed for Big Rivers' members. Big Rivers' members' consumer classes include the following:

1. Residential
2. Small Commercial
3. Large Commercial
4. Public Street and Highway Lighting

Big Rivers' total system energy requirements were calculated as the sum of the above components of the members' systems.

FORECASTS BY CONSUMER CLASS

Forecast Results. The following sections discuss the results of the forecasts of consumers and energy sales by class for each of the distribution member cooperatives that Big Rivers serves. Many models were developed in the process of developing Big Rivers' forecast. Because of this, the models are discussed in a generic sense only. For a detailed description of a particular model, refer to the appropriate distribution cooperative PRS report.

Number of Consumers. The residential class is by far the largest consumer class on Big Rivers' system, accounting for nearly 89.4 percent of Big Rivers' member distribution cooperatives' consumers in 1998. The small commercial class accounted for approximately 10.4 percent of Big Rivers' members' consumers. The remaining consumers are made up of the various consumer classes listed earlier on page II-3.

The aggregate forecast of the number of consumers by consumer class is shown in Table II-3. This table indicates that Big Rivers' members' residential consumers are forecast to increase from 86,615 in 1998 to 127,391 by 2018. This equates to an average annual increase of 1.9 percent, which compares to historical growth of 1.8 percent annually from 1979 to 1998. The number of small commercial consumers is forecast to increase at an average annual rate of 2.0 percent, which compares to average annual growth of 2.7 percent from 1979 to 1998.

Big Rivers' members' total number of consumers is projected to increase from 96,152 in 1998 to 141,608 by 2018. This equates to expected average annual increases of 2.0 percent, which compares to historical growth of 1.9 percent annually from 1979 to 1998. Thus, Big Rivers' members' consumer base is expected to increase at a rate slightly higher than that experienced over the past 20 years.

Energy Sales by Consumer Class

Residential. In 1998, sales to the residential class made up approximately 64.8 percent of Big Rivers' member cooperatives' total rural system energy requirements and 36.4 percent of total energy requirements to all consumers except the smelters. Energy sales to the residential sector grew at an average annual rate of 2.6 percent during the study period (1979 to 1998). This compares to the national average residential sales growth of 2.7 percent per year over the same period.

Residential electricity sales are often strongly related to the number of residential consumers. Many times this relationship is so strong that it overshadows other factors influencing residential energy sales. Therefore, residential energy sales per consumer was used as the dependent variable in a separate model in order to isolate the variation in sales due to factors other than the

Table II-3

NUMBER OF CONSUMERS BY CONSUMER CLASS

Big Rivers Electric Corporation

	Year	Residential	Small Commercial	Large Commercial	Public Street & Highway	Total Consumers
	1979	61,858	5,616	17	76	67,567
	1980	63,049	5,800	18	74	68,940
	1981	63,941	6,061	19	76	70,097
	1982	64,502	6,272	22	84	70,880
	1983	65,519	6,619	23	93	72,255
	1984	66,607	6,916	25	98	73,646
	1985	67,753	7,022	27	99	74,901
	1986	68,871	7,152	33	96	76,152
	1987	69,945	7,296	34	101	77,375
	1988	71,033	7,425	36	104	78,597
	1989	72,170	7,525	40	109	79,844
	1990	73,156	7,730	40	116	81,042
	1991	74,176	7,854	40	121	82,190
	1992	75,667	7,897	38	124	83,727
	1993	77,266	8,060	37	129	85,492
	1994	78,879	8,198	44	134	87,256
	1995	80,808	8,407	42	136	89,393
	1996	82,658	8,690	46	152	91,545
	1997	84,622	9,015	48	158	93,843
Historical	1998	86,615	9,326	50	161	96,152
Projected	1999	88,790	9,636	51	164	98,641
	2000	90,959	9,860	54	167	101,040
	2001	93,003	10,088	54	169	103,314
	2002	95,057	10,310	54	172	105,593
	2003	97,100	10,532	55	175	107,862
	2004	99,130	10,754	55	177	110,116
	2005	101,209	10,979	55	180	112,423
	2006	103,277	11,203	56	182	114,718
	2007	105,383	11,426	56	185	117,050
	2008	107,529	11,653	56	188	119,425
	2009	109,621	11,884	57	190	121,753
	2010	111,699	12,111	57	193	124,061
	2011	113,613	12,344	57	196	126,210
	2012	115,555	12,569	58	199	128,381
	2013	117,482	12,792	58	202	130,534
	2014	119,461	13,026	58	205	132,750
	2015	121,416	13,254	59	208	134,937
	2016	123,410	13,487	59	211	137,166
	2017	125,402	13,714	59	214	139,389
	2018	127,391	13,940	60	217	141,608

Average Annual Compound Growth Rates:

	Residential	Small Commercial	Large Commercial	Public Street & Highway	Total Consumers
1979-1998	1.8%	2.7%	5.8%	4.1%	1.9%
1993-1998	2.3%	3.0%	5.9%	4.5%	2.4%
1998-2003	2.3%	2.5%	2.1%	1.6%	2.3%
1998-2018	1.9%	2.0%	1.0%	1.5%	2.0%

variation in the number of consumers. A cross-sectional or pooled econometric model was developed to forecast residential energy sales per consumer for Big Rivers' member distribution cooperatives. Variables in this equation included the real price of residential electricity, heating degree days, and real per capita income.

The total residential energy sales projections were calculated by multiplying the projected number of residential consumers times the residential energy sales per consumer projections. The average annual compound growth rate for this class' consumption was 2.6 percent over the historical period of 1993 to 1998. In 1998, sales to the residential class totaled 1,199,476 MWh. Total residential energy sales are projected to increase to 2,196,184 MWh in 2018, an average annual compound growth rate of 3.1 percent. This forecast is shown in Table II-4.

Small Commercial. The small commercial class is defined as commercial accounts with less than 1000 kVA transformer capacity. Typical consumers in this class include small farming operations, service stations, restaurants and other retail establishments. In 1997, the small commercial class accounted for 23 percent of Big Rivers' total rural energy requirements.

Small commercial energy sales have historically grown faster than residential sales for Big Rivers as a whole, with average annual growth of 3.6 percent from 1979 to 1998 versus 2.6 percent for the residential class over the same time frame. For Big Rivers, as a whole, small commercial sales are projected to increase from the 1998 level of 427,835 MWh to 739,515 MWh by 2018. This represents an average annual growth rate of 2.8 percent, which is somewhat smaller than the historical period growth rate. This is primarily due to the consumer forecast shown on Table II-2, which projects consumer growth at rates less than historically experienced.

Large Commercial. The large commercial class includes commercial accounts with greater than 1000 kVA transformer capacity. A portion of these accounts is directly served by Big Rivers while the remainder is served by the respective cooperative. In 1998, the non-rural large commercial class accounted for approximately 78.1 percent of Big Rivers' total system energy requirements. By contrast Big Rivers' members' rural large commercial consumers contributed 5.6 percent to Big Rivers' total rural energy requirements in 1998 and 1.2 percent to Big Rivers' total energy requirements. All large commercial energy sales were generally forecast judgmentally taking into consideration past trends and expected future developments. Information for these projections was supplied by the members and/or the individual consumers.

Table II-4

SUMMATION OF MEMBER COOPERATIVES' ENERGY SALES BY CONSUMER CLASS

Big Rivers Electric Corporation
(MWh)

	Year	Residential Sales	Small Commercial Sales	Large Commercial Sales	Public Street & Highway	Total Member System Sales	Member System Own Use	Member System Distribution Losses	Total Member System Energy Requirements	Total Rural Energy Requirements	Non-rural (Smelters)	Total Non-rural (Incl. Smelters)	Total Energy Requirements Less Smelters	Total Energy Requirements for Generation Service Provided by Big Rivers [1]
	1979	735,825	217,825	5,973,411	2,210	6,929,271	2,909	98,784	7,029,485	1,088,620	5,500,327	5,940,865	1,529,158	1,669,747
	1980	795,980	235,321	6,421,525	2,032	7,454,859	2,754	69,825	7,528,564	1,138,221	5,935,116	6,390,343	1,593,448	1,744,019
	1981	745,835	241,341	6,411,878	1,985	7,401,040	2,810	74,454	7,479,670	1,098,611	5,893,803	6,381,059	1,585,867	1,735,461
	1982	756,931	253,355	5,330,458	1,999	6,342,743	2,932	86,998	6,426,261	1,125,806	4,732,186	5,300,454	1,694,075	1,822,600
	1983	781,501	259,602	5,561,107	1,833	6,604,043	2,816	91,932	6,707,235	1,178,499	4,880,411	5,528,736	1,826,824	1,960,969
	1984	819,670	279,805	6,228,632	1,887	7,329,994	3,042	73,277	7,398,951	1,204,342	5,495,014	6,194,609	1,903,937	2,051,916
	1985	819,928	289,908	5,684,642	1,927	6,796,406	2,864	95,936	6,899,093	1,245,780	4,964,900	5,653,312	1,934,193	2,072,174
	1986	871,530	290,082	4,962,292	1,981	6,125,886	2,982	86,695	6,215,491	1,288,785	4,198,758	4,926,706	2,016,733	2,141,043
	1987	909,195	301,409	4,967,375	2,048	6,180,027	3,079	90,507	6,270,519	1,340,439	4,163,243	4,930,080	2,107,276	2,232,686
	1988	931,639	314,841	6,464,563	2,110	7,713,154	3,196	100,622	7,813,146	1,385,417	5,627,682	6,427,729	2,185,464	2,341,727
	1989	925,721	319,729	6,703,573	2,154	7,951,178	3,255	112,363	8,072,761	1,405,199	5,862,015	6,667,563	2,210,746	2,372,202
	1990	930,785	335,203	6,845,797	2,177	8,113,962	3,133	78,608	8,191,465	1,382,220	5,916,778	6,809,244	2,274,687	2,438,516
	1991	991,459	342,875	6,871,879	2,276	8,208,490	3,136	102,337	8,314,440	1,480,680	5,969,212	6,833,760	2,345,228	2,511,517
	1992	945,487	347,706	6,927,025	2,275	8,222,493	3,043	100,446	8,326,337	1,440,331	6,001,284	6,886,006	2,325,053	2,491,580
	1993	1,052,301	368,541	6,913,643	2,417	8,336,902	3,090	106,578	8,445,131	1,581,744	5,966,768	6,863,387	2,478,363	2,647,265
	1994	1,040,652	360,612	5,953,034	2,509	7,356,808	3,226	97,690	7,454,549	1,571,485	4,942,862	5,883,064	2,511,687	2,660,778
	1995	1,101,490	381,680	6,364,586	2,641	7,850,397	3,334	104,959	7,961,752	1,666,327	5,162,811	6,295,425	2,798,941	2,958,176
	1996	1,144,623	389,824	6,395,950	2,661	7,933,058	3,599	111,432	7,882,784	1,728,680	5,028,097	6,154,104	2,854,687	3,012,342
	1997	1,137,995	411,100	6,463,933	2,802	8,015,830	3,305	107,102	8,071,289	1,755,841	5,032,885	6,315,447	3,038,404	3,199,829
Historical	1998	1,199,476	427,835	6,693,375	2,846	8,323,532	3,439	105,892	8,438,991	1,849,759	5,142,775	6,589,232	3,296,216	3,464,995
Projected	1999	1,259,340	453,983	7,738,820	2,919	9,455,062	3,754	117,617	9,575,331	1,987,841	5,954,580	7,587,490	3,620,751	3,686,368
	2000	1,304,839	467,495	7,898,769	2,994	9,674,097	3,874	122,055	9,798,109	2,071,466	5,954,580	7,726,643	3,843,529	3,913,183
	2001	1,346,101	484,181	7,929,401	3,071	9,762,753	3,974	125,612	9,891,378	2,139,659	5,954,580	7,751,719	3,936,798	4,008,143
	2002	1,390,125	497,050	7,950,264	3,150	9,840,590	4,049	128,781	9,972,428	2,200,154	5,954,580	7,772,274	4,017,848	4,090,662
	2003	1,434,575	513,549	7,955,388	3,231	9,906,743	4,136	132,389	10,042,236	2,269,407	5,954,580	7,772,829	4,087,656	4,161,735
	2004	1,479,959	526,460	7,955,901	3,307	9,965,626	4,213	135,600	10,104,380	2,331,366	5,954,580	7,773,014	4,149,800	4,225,005
	2005	1,526,957	543,310	7,956,437	3,384	10,030,088	4,303	139,101	10,172,395	2,399,185	5,954,580	7,773,211	4,217,815	4,294,253
	2006	1,574,812	556,416	7,970,756	3,464	10,105,448	4,384	142,438	10,251,368	2,468,439	5,954,580	7,782,929	4,296,788	4,374,657
	2007	1,614,989	569,730	7,971,315	3,546	10,159,580	4,457	145,543	10,308,418	2,525,293	5,954,580	7,783,125	4,353,838	4,432,741
	2008	1,666,353	583,208	7,971,885	3,629	10,225,075	4,541	149,065	10,377,491	2,594,170	5,954,580	7,783,321	4,422,911	4,503,066
	2009	1,717,305	600,739	7,995,762	3,715	10,317,521	4,634	152,492	10,473,432	2,670,871	5,954,580	7,802,561	4,518,852	4,600,745
	2010	1,768,755	614,364	8,139,183	3,803	10,526,105	4,716	155,748	10,685,555	2,739,972	5,954,580	7,945,584	4,730,975	4,816,713
	2011	1,818,598	632,098	8,139,792	3,894	10,594,382	4,810	159,266	10,757,432	2,811,652	5,954,580	7,945,780	4,802,852	4,889,892
	2012	1,870,906	645,678	8,144,664	3,986	10,665,234	4,898	162,891	10,831,992	2,886,015	5,954,580	7,945,976	4,877,412	4,965,803
	2013	1,923,101	662,817	8,202,431	4,081	10,792,431	4,996	166,474	10,962,843	2,959,540	5,954,580	8,003,303	5,008,263	5,099,026
	2014	1,976,375	676,987	8,203,081	4,179	10,860,623	5,083	169,920	11,034,559	3,031,059	5,954,580	8,003,500	5,079,979	5,172,041
	2015	2,029,910	694,433	8,207,997	4,279	10,936,620	5,183	173,731	11,114,451	3,110,755	5,954,580	8,003,696	5,159,871	5,253,381
	2016	2,084,597	708,526	8,208,949	4,382	11,006,454	5,273	177,192	11,187,829	3,183,665	5,954,580	8,004,164	5,233,249	5,328,089
	2017	2,139,992	725,893	8,209,918	4,487	11,080,290	5,375	180,853	11,265,409	3,260,777	5,954,580	8,004,632	5,310,829	5,407,075
	2018	2,196,184	739,515	8,272,283	4,596	11,212,578	5,468	139,494	11,401,449	3,339,218	5,954,580	8,062,230	5,446,869	5,545,580
Average Annual Compound Growth Rates:														
	1979-1998	2.6%	3.6%	0.6%	1.3%	1.0%	0.9%	0.4%	1.0%	2.8%	-0.4%	0.5%	4.1%	3.9%
	1993-1998	2.7%	3.0%	-0.6%	3.3%	0.0%	2.2%	-0.1%	0.0%	3.2%	-2.9%	-0.8%	5.9%	5.5%
	1998-2003	3.6%	3.7%	3.5%	2.6%	3.5%	3.8%	4.6%	3.5%	4.2%	3.0%	3.4%	4.4%	3.7%
	1998-2018	3.1%	2.8%	1.1%	2.4%	1.5%	2.3%	1.4%	1.5%	3.0%	0.7%	1.0%	2.5%	2.4%

[1] Includes Big Rivers' line losses. Losses for 1979 - 1998 were based on 2 percent of member cooperatives total energy requirements. Forecasted losses for the period 1999 - 2018 were based on the formula (1 - 0.0178) multiplied by the forecasted generation sales. This includes all sales except those to the smelters.

The sum of the members' forecasts indicates non-rural large commercial sales are projected to increase from the 1998 level of 6,693,375 MWh to 8,272,283 MWh by 2018. This represents an average annual compound growth rate of 1.1 percent over the entire forecast period. But, as this class is extremely sensitive to economic conditions, a prolonged economic expansion could contribute significantly to large commercial class growth rate.

Other Classes. Public street and highway lighting sales were forecast judgmentally. These projections were developed taking into consideration past trends and expected future developments. In addition, adjustments were made for known developments in the service area for each member cooperative. These miscellaneous class forecasts were shown earlier in Table II-4.

The members' own use and losses forecasts were generally based on the 1993 to 1997 weighted averages of their own use and losses. Borrower's own use and losses are defined as the energy the members purchase from Big Rivers less total sales to the members' customers.

TOTAL SYSTEM ENERGY REQUIREMENTS

Historical and projected energy sales by consumer class for Big Rivers' members are shown in Table II-4 and depicted graphically in Figure II-1. Big Rivers' total system energy requirements, calculated as the sum of the class energy forecasts described above, are projected to grow approximately 1.5 percent per year from 1998 to 2018. This compares to total system sales growth of 1.0 percent annually from 1979 to 1998. This forecast is dominated by the non-rural (large commercial) class, which is in turn dominated by the Alcan and Southwire accounts at Henderson-Union and Green River, respectively. This class comprised approximately 78 percent of Big Rivers' members' 1998 sales, and is expected to maintain fairly constant energy consumption over the forecast period. The two large smelter accounts will continue to receive transmission services from Big Rivers but will no longer receive generation services from Big Rivers.

Total energy requirements for generation services provided by Big Rivers are shown in the column to the far right. This total includes Big Rivers' losses that, by contract, are computed using the formula, (1 – 0.0178).

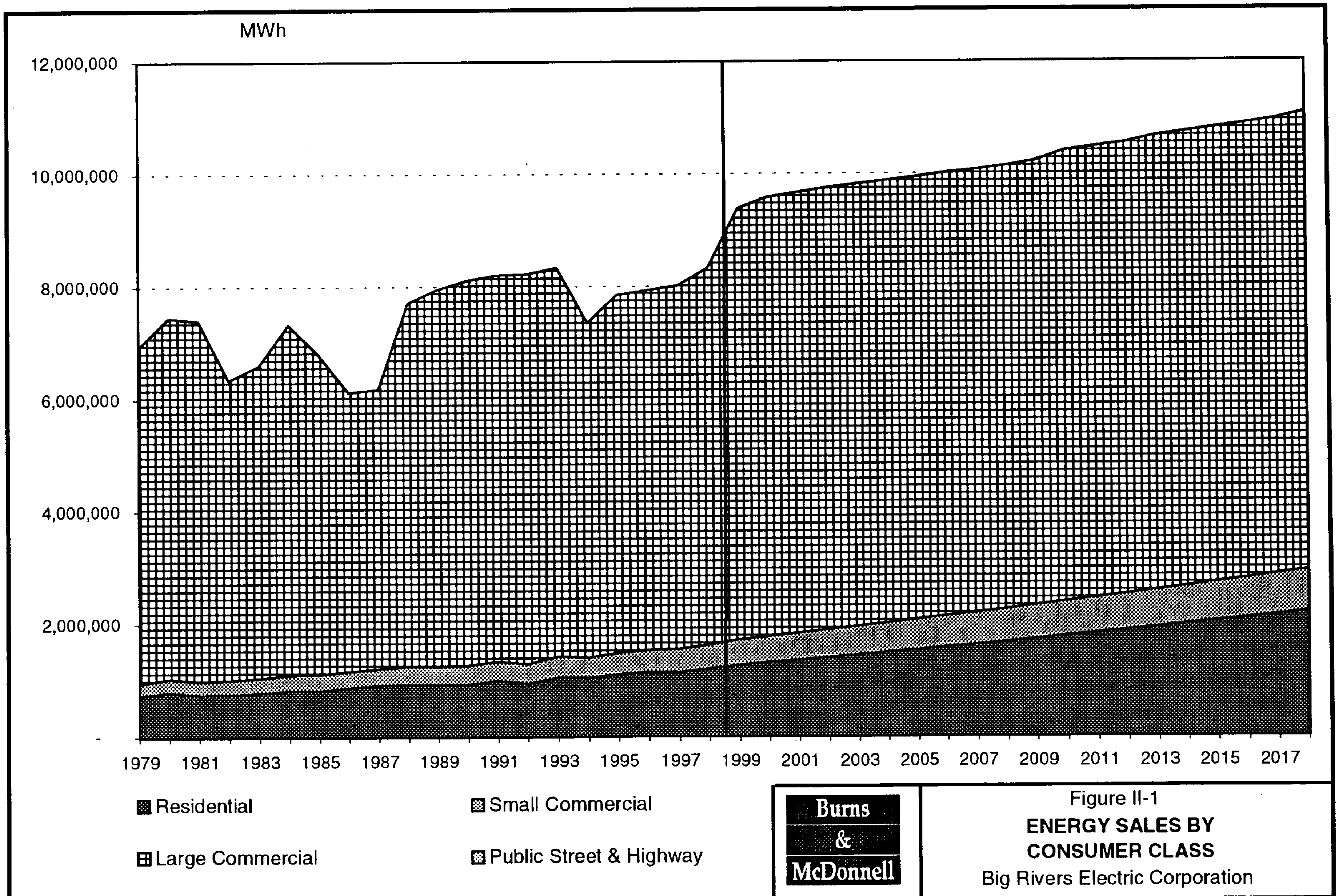


Figure II-1
ENERGY SALES BY CONSUMER CLASS
Big Rivers Electric Corporation

Big Rivers' energy requirements by member cooperative are shown in Table II-5 and depicted graphically in Figure II-2. Rural energy requirements were 1,849,759 MWh in 1998. Rural energy requirements are projected to increase to 3,339,218 MWh by 2018. This equates to an average annual compound growth rate of 3.0 percent. This compares to a rate of 2.8 percent over the previous twenty years.

DEMAND

Rural Peak Demand. Rural system demand is displayed in Table II-6. Rural system demand was 425.0 MW in 1998 and is expected to reach 765.0 MW by the year 2018. This growth amounts to an average annual percentage increase of 3.0 percent over the twenty-year forecast period. From 1994 to 1998 the systems rural demand grew at an average annual compound growth rate of 4.3 percent per year. This difference in growth rates can be attributed to increased demand from rural large consumers on the system.

Total System Peak Demand. Total system demand is displayed in Table II-7. Total system demand was 1,266.4 MW in 1998 and is expected to reach 1,728.6 MW by the year 2018. This growth amounts to an average annual percentage increase of 1.6 percent over the twenty-year forecast period. From 1994 to 1998 the systems' total demand grew at an average annual rate of 1.1 percent per year. This difference in growth rates can be attributed to several reasons. Firstly, demand for the smelters decreased from 1994 to 1995 and then grew but hadn't returned to the 1994 level by 1998. Smelter demand is expected to increase in 1999 with the addition of a new pot line at Southwire. Rural demand is expected to increase at a rate higher than the historical rate due to healthy growth in the local economy.

SHORT-TERM FORECASTS

Energy. The short-term rural energy forecast is displayed in Table II-8. Monthly rural energy sales for each member cooperative for the years 1994 to 1998 were used to project monthly rural energy sales for the years 1999 through 2002. The individual members' short-term forecasts predict that rural energy sales for Big Rivers will reach 2,179,802 MWh by the year 2002. This expected value is less then the long-term forecast of 2,200,154 MWh by 20,352 MWh. The forecast indicates that the average annual compound growth rate of rural energy sales in the short-term will be 4.2 percent, which is identical to the system growth over the previous five years.

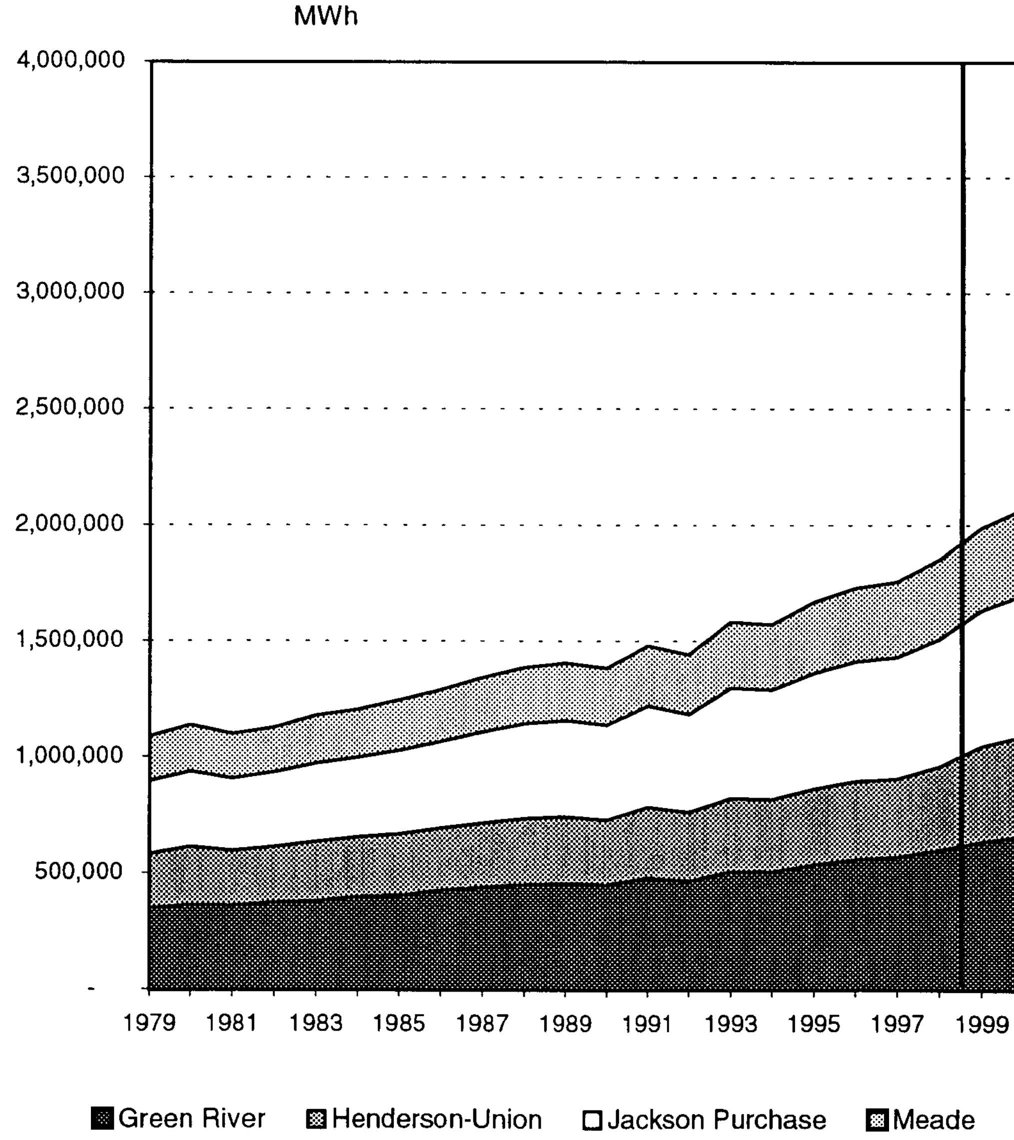
Table II-5

ENERGY REQUIREMENTS BY MEMBER COOPERATIVE

Big Rivers Electric Corporation
(MWh)

		Green River		Henderson-Union		Jackson Purchase		Meade	Member Energy Requirements			
	Year	Rural [1]	Non-Rural	Rural [1]	Non-Rural	Rural [1]	Non-Rural	Rural [1]	Rural Requirements[1]	Non-Rural Requirements	Total System Energy Requirements	Percent Increase
	1979	348,133	3,481,324	233,918	2,398,544	311,719	60,996	194,850	1,088,620	5,940,865	7,029,485	--
	1980	361,946	3,490,542	249,882	2,852,509	323,793	47,292	202,600	1,138,221	6,390,343	7,528,564	7.1%
	1981	357,739	3,512,113	239,909	2,840,390	307,847	28,557	193,116	1,098,611	6,381,059	7,479,670	-0.6%
	1982	371,696	3,060,568	242,388	2,220,158	318,562	19,728	193,160	1,125,806	5,300,454	6,426,261	-14.1%
	1983	377,308	3,346,092	257,868	2,158,526	336,349	24,118	206,975	1,178,499	5,528,736	6,707,235	4.4%
	1984	397,142	3,522,522	257,962	2,650,581	342,009	21,507	207,229	1,204,342	6,194,609	7,398,951	10.3%
	1985	402,230	3,527,640	265,937	2,107,550	358,127	18,122	219,486	1,245,780	5,653,312	6,899,093	-6.8%
	1986	424,946	3,450,619	268,604	1,446,718	371,683	29,369	223,551	1,288,785	4,926,706	6,215,491	-9.9%
	1987	439,582	3,440,681	274,134	1,463,019	392,503	26,380	234,220	1,340,439	4,930,080	6,270,519	0.9%
	1988	448,964	3,674,113	285,213	2,727,714	408,454	25,902	242,787	1,385,417	6,427,729	7,813,146	24.6%
	1989	454,896	3,682,361	288,963	2,941,645	413,521	43,557	247,819	1,405,199	6,667,563	8,072,761	3.3%
	1990	448,897	3,751,912	279,997	3,005,333	408,327	51,999	245,000	1,382,220	6,809,244	8,191,465	1.5%
	1991	481,152	3,752,691	301,930	3,034,457	435,713	46,612	261,885	1,480,680	6,833,760	8,314,440	1.5%
	1992	466,148	3,759,923	294,600	3,076,974	424,027	49,109	255,556	1,440,331	6,886,006	8,326,337	0.1%
	1993	506,644	3,714,817	314,890	3,089,720	476,722	58,850	283,486	1,581,744	6,863,387	8,445,131	1.4%
	1994	505,269	3,606,026	312,544	2,222,594	470,277	54,444	283,394	1,571,485	5,883,064	7,454,549	-11.7%
	1995	536,035	3,830,348	324,688	2,413,793	499,495	51,284	306,109	1,666,327	6,295,425	7,961,752	6.8%
	1996	557,460	3,879,475	336,959	2,219,234	517,057	55,395	317,204	1,728,680	6,154,104	7,882,784	-1.0%
	1997	567,963	4,040,072	337,440	2,222,508	524,250	52,867	326,188	1,755,841	6,315,447	8,071,289	2.4%
Historical	1998	599,520	4,250,975	357,541	2,281,498	550,304	56,759	342,393	1,849,759	6,589,232	8,438,991	4.6%
Projected	1999	634,319	5,209,692	412,491	2,321,040	584,162	56,758	356,869	1,987,841	7,587,490	9,575,331	13.5%
	2000	659,145	5,348,845	432,048	2,321,040	606,911	56,758	373,361	2,071,466	7,726,643	9,798,109	2.3%
	2001	687,196	5,373,921	440,349	2,321,040	625,058	56,758	387,055	2,139,659	7,751,719	9,891,378	1.0%
	2002	705,621	5,394,476	449,039	2,321,040	644,075	56,758	401,419	2,200,154	7,772,274	9,972,428	0.8%
	2003	728,150	5,395,031	457,790	2,321,040	667,216	56,758	416,251	2,269,407	7,772,829	10,042,236	0.7%
	2004	747,299	5,395,216	466,555	2,321,040	685,842	56,758	431,669	2,331,366	7,773,014	10,104,380	0.6%
	2005	770,643	5,395,413	475,615	2,321,040	705,415	56,758	447,511	2,399,185	7,773,211	10,172,395	0.7%
	2006	790,547	5,405,131	484,828	2,321,040	729,162	56,758	463,902	2,468,439	7,782,929	10,251,368	0.8%
	2007	807,586	5,405,327	494,441	2,321,040	745,884	56,758	477,383	2,525,293	7,783,125	10,308,418	0.6%
	2008	828,399	5,405,523	504,288	2,321,040	766,747	56,758	494,736	2,594,170	7,783,321	10,377,491	0.7%
	2009	851,644	5,424,763	514,299	2,321,040	792,392	56,758	512,536	2,670,871	7,802,561	10,473,432	0.9%
	2010	871,390	5,567,786	524,368	2,321,040	813,534	56,758	530,680	2,739,972	7,945,584	10,685,555	2.0%
	2011	895,184	5,567,982	534,573	2,321,040	836,065	56,758	545,830	2,811,652	7,945,780	10,757,432	0.7%
	2012	915,797	5,568,178	545,580	2,321,040	863,481	56,758	561,158	2,886,015	7,945,976	10,831,992	0.7%
	2013	940,390	5,625,505	556,378	2,321,040	886,212	56,758	576,560	2,959,540	8,003,303	10,962,843	1.2%
	2014	961,344	5,625,702	567,217	2,321,040	910,138	56,758	592,359	3,031,059	8,003,500	11,034,559	0.7%
	2015	986,371	5,625,898	578,148	2,321,040	937,934	56,758	608,303	3,110,755	8,003,696	11,114,451	0.7%
	2016	1,007,794	5,626,366	589,127	2,321,040	962,266	56,758	624,478	3,183,665	8,004,164	11,187,829	0.7%
	2017	1,033,355	5,626,834	600,480	2,321,040	986,156	56,758	640,786	3,260,777	8,004,632	11,265,409	0.7%
	2018	1,055,472	5,684,432	611,902	2,321,040	1,014,490	56,758	657,353	3,339,218	8,062,230	11,401,449	1.2%
Average Annual Compound Growth Rates:												
	1979-1998	2.9%	1.1%	2.3%	-0.3%	3.0%	-0.4%	3.0%	2.8%	0.5%	1.0%	
	1993-1998	3.4%	2.7%	2.6%	-5.9%	2.9%	-0.7%	3.8%	3.2%	-0.8%	0.0%	
	1998-2003	4.0%	4.9%	5.1%	0.3%	3.9%	0.0%	4.0%	4.2%	3.4%	3.5%	
	1998-2018	2.9%	1.5%	2.7%	0.1%	3.1%	0.0%	3.3%	3.0%	1.0%	1.5%	

[1] Total energy requirements for rural consumers include line losses.



Burns & McDonnell

Figure II-2
RURAL ENERGY REQUIREMENTS BY MEMBER COOPERATIVE
Big Rivers Electric Corporation

Table II-6

RURAL SYSTEM ENERGY REQUIREMENTS,
PEAK DEMAND AND LOAD FACTOR
Big Rivers Electric Corporation

		Rural System Energy Requirements		Rural System Peak Demand [1]		Coincident Load Factor
	Year	(MWh)	Percent Increase	(kW)	Percent Increase	Percent
	1994	1,571,485	--	359,832	--	49.9
	1995	1,666,327	6.0%	387,914	7.8%	49.0
	1996	1,728,680	3.7%	382,214	-1.5%	51.6
	1997	1,755,841	1.6%	409,524	7.1%	48.9
Historical	1998	1,849,759	5.3%	425,035	3.8%	49.7
Projected	1999	1,987,841	7.5%	455,400 [2]	7.1%	49.8 [3]
	2000	2,071,466	4.2%	474,558	4.2%	49.8
	2001	2,139,659	3.3%	490,180	3.3%	49.8
	2002	2,200,154	2.8%	504,039	2.8%	49.8
	2003	2,269,407	3.1%	519,905	3.1%	49.8
	2004	2,331,366	2.7%	534,099	2.7%	49.8
	2005	2,399,185	2.9%	549,636	2.9%	49.8
	2006	2,468,439	2.9%	565,501	2.9%	49.8
	2007	2,525,293	2.3%	578,526	2.3%	49.8
	2008	2,594,170	2.7%	594,305	2.7%	49.8
	2009	2,670,871	3.0%	611,877	3.0%	49.8
	2010	2,739,972	2.6%	627,708	2.6%	49.8
	2011	2,811,652	2.6%	644,129	2.6%	49.8
	2012	2,886,015	2.6%	661,165	2.6%	49.8
	2013	2,959,540	2.5%	678,009	2.5%	49.8
	2014	3,031,059	2.4%	694,394	2.4%	49.8
	2015	3,110,755	2.6%	712,651	2.6%	49.8
	2016	3,183,665	2.3%	729,355	2.3%	49.8
	2017	3,260,777	2.4%	747,020	2.4%	49.8
	2018	3,339,218	2.4%	764,991	2.4%	49.8

Average Annual Compound Growth Rates:

	Energy	Peak Demand
1994-1998	4.2%	4.3%
1998-2003	4.2%	4.1%
1998-2018	3.0%	3.0%

Table II-7

TOTAL SYSTEM ENERGY REQUIREMENTS,
PEAK DEMAND AND LOAD FACTOR
Big Rivers Electric Corporation

	Year	Total System Energy Requirements (MWh)	Percent Increase	Non-Rural Demand Net of Smelters (kW)	Smelters' Demand (kW)	Rural System Demand (kW)	Total System Demand[1] (kW)	Percent Increase	Load Factor Percent
	1994	7,454,549	--	149,714	703,908	359,832	1,213,454	--	70.1
	1995	7,961,752	6.8%	164,899	591,154	387,914	1,143,967	-5.7%	79.4
	1996	7,882,784	-1.0%	183,530	594,229	382,214	1,159,973	1.4%	77.6
	1997	8,071,289	2.4%	188,129	598,802	409,524	1,196,455	3.1%	77.0
Historical	1998	8,438,991	4.6%	236,339	605,069	425,035	1,266,443	5.8%	76.1
Projected	1999	9,575,331	13.5%	227,228	686,000	455,400	1,368,628	8.1%	79.9
	2000	9,798,109	2.3%	242,228	686,000	474,558	1,402,785	2.5%	79.7
	2001	9,891,378	1.0%	245,228	686,000	490,180	1,421,408	1.3%	79.4
	2002	9,972,428	0.8%	247,228	686,000	504,039	1,437,267	1.1%	79.2
	2003	10,042,236	0.7%	247,228	686,000	519,905	1,453,132	1.1%	78.9
	2004	10,104,380	0.6%	247,428	686,000	534,099	1,467,527	1.0%	78.6
	2005	10,172,395	0.7%	247,428	686,000	549,636	1,483,063	1.1%	78.3
	2006	10,251,368	0.8%	248,428	686,000	565,501	1,499,929	1.1%	78.0
	2007	10,308,418	0.6%	248,428	686,000	578,526	1,512,954	0.9%	77.8
	2008	10,377,491	0.7%	248,428	686,000	594,305	1,528,733	1.0%	77.5
	2009	10,473,432	0.9%	250,428	686,000	611,877	1,548,305	1.3%	77.2
	2010	10,685,555	2.0%	265,428	686,000	627,708	1,579,135	2.0%	77.2
	2011	10,757,432	0.7%	265,428	686,000	644,129	1,595,557	1.0%	77.0
	2012	10,831,992	0.7%	265,428	686,000	661,165	1,612,593	1.1%	76.7
	2013	10,962,843	1.2%	271,428	686,000	678,009	1,635,437	1.4%	76.5
	2014	11,034,559	0.7%	271,428	686,000	694,394	1,651,821	1.0%	76.3
	2015	11,114,451	0.7%	271,628	686,000	712,651	1,670,279	1.1%	76.0
	2016	11,187,829	0.7%	271,628	686,000	729,355	1,686,982	1.0%	75.7
	2017	11,265,409	0.7%	271,628	686,000	747,020	1,704,648	1.0%	75.4
	2018	11,401,449	1.2%	277,628	686,000	764,991	1,728,618	1.4%	75.3

Average Annual Compound Growth Rates:

	Energy	Non-Rural	Smelters'	Rural	Total System
1994-1998	3.1%	12.1%	-3.7%	4.3%	1.1%
1998-2003	3.5%	0.9%	2.5%	4.1%	2.8%
1998-2018	1.5%	0.8%	0.6%	3.0%	1.6%

[1] System peak demand equals rural system coincident peak demand plus non-rural non-coincident peak demand.

Table II-8

SUMMARY OF SHORT-TERM RURAL FORECASTS
BY MEMBER COOPERATIVE
Big Rivers Electric Corporation

	Green River Rural Consumers		**Henderson-Union** Rural Consumers		**Jackson Purchase** Rural Consumers		**Meade** Rural Consumers		**Total** Rural Consumers		
Year	Energy (MWh)	Demand kW[1]	Energy (MWh)	Demand kW[1]	Energy (MWh)	Demand kW[1]	Energy (MWh)	Demand kW[1]	Energy (MWh)	Demand kW[1]	Load Factor
1994	505,269	117,295	312,544	74,983	470,277	108,506	283,394	70,410	1,571,485	371,194	48.33
1995	536,035	126,586	324,688	71,794	499,495	121,330	306,109	68,724	1,666,327	388,434	48.97
1996	557,460	123,476	336,959	76,962	517,057	117,763	317,204	75,455	1,728,680	393,656	50.13
1997	567,963	135,829	337,440	75,245	524,250	127,059	326,188	75,295	1,755,841	413,428	48.48
1998	599,520	141,552	357,541	79,118	550,304	128,946	342,393	75,683	1,849,759	425,299	49.65
1999	622,995	145,284	411,849	86,506	589,861	132,384	355,463	79,025	1,980,168	443,199	51.00
2000	650,608	150,805	432,378	88,742	613,601	136,338	364,481	82,246	2,061,067	458,130	51.36
2001	674,070	156,325	443,254	90,724	632,443	140,291	373,258	85,468	2,123,024	472,808	51.26
2002	692,733	161,846	454,295	92,750	651,179	144,245	381,595	88,689	2,179,802	487,530	51.04

Average Annual Compound Growth Rates:

1994-1998	4.4%	4.8%	3.4%	1.4%	4.0%	4.4%	4.8%	1.8%	4.2%	3.5%
1998-2002	3.7%	3.4%	6.2%	4.1%	4.3%	2.8%	2.7%	4.0%	4.2%	3.5%

[1] Rural coincident peak demand. Big Rivers peak may not equal the sum of the cooperatives peak because these peaks may have occurred in different months.

Demand. The short-term rural demand forecast is also displayed in Table II-8. Monthly rural coincident peak demand for each member cooperative for the years 1994 to 1998 was used to project monthly rural coincident peak demand for the years 1999 through 2002. The individual members' short-term forecasts predict that rural peak demand for Big Rivers will reach 487.5 MW by the year 2002. This expected value is slightly less than the long-term forecast of 504.0 MW. The difference between the two forecasts reflects the addition of numerous large commercial loads, in the short-term, that are not accounted for in the last five years of trend data, and the fact that the long-term peak demand forecast is tied directly to the long-term energy forecast via expected load factor. The forecast indicates that the average annual growth rate of rural peak demand, in the short-term, will be 3.5 percent, which is a bit higher than the historical five-year period.

Non-rural. Table II-9 displays the short-term growth predictions for the non-rural portion of Big Rivers' load. The top portion of Table II-9 addresses the complete non-rural load and the bottom portion addresses the Alcan and Southwire smelters only. Total non-rural demand is expected to reach 933.2 MW by the year 2002. Of that amount, 686.0 MW will pertain to the two smelter accounts.

PENDING CONSOLIDATION

The Kentucky Public Service Commission approved the merger of Henderson-Union Electric Cooperative and Green River Electric Cooperative on July 1, 1999. The name of the new cooperative is Kenergy and headquarters for the combined unit are in Henderson, Kentucky. The management of both cooperatives believes that the combination of their operations will result in increased operational efficiency and cost savings over the long term. The benefits of this merger include a 4 percent rate reduction for all consumers that went immediately into effect after the consolidation. The combination of Henderson-Union and Green River created a single cooperative that serves portions of 14 counties in the western area of the state. The new cooperative has over 48,000 consumers.

Comparison With Other Forecasts

The Energy Information Administration has forecast total United States net energy for load to grow at 1.4 percent per year through 2020 (Annual Energy Outlook 1998). The administration also predicts that the prime drivers of overall U.S. electricity sales growth will be the residential class at 1.5 percent per year, most of which (87 percent) will be due to an increased use of

Table II-9

SUMMARY OF SHORT-TERM NON-RURAL FORECASTS
BY MEMBER COOPERATIVE
Big Rivers Electric Corporation

Total Non-Rural Sales and Demand

	Green River Total Non-rural		Henderson-Union Total Non-rural		Jackson Purchase Non-rural		Total Non-rural		
Year	Energy (MWh)	Demand kW	Energy (MWh)	Demand kW	Energy (MWh)	Demand kW	Energy (MWh)	Demand kW	Load Factor
1994	3,606,026	456,521	2,222,594	385,891	54,444	11,210	5,883,064	853,622	78.67
1995	3,830,348	472,141	2,413,793	272,792	51,284	11,120	6,295,425	756,053	95.05
1996	3,879,475	484,770	2,219,234	284,284	55,395	8,705	6,154,104	777,759	90.33
1997	4,040,072	498,587	2,222,508	277,944	52,867	10,400	6,315,447	786,931	91.61
1998	4,250,975	527,918	2,281,498	302,668	56,759	10,822	6,589,232	841,408	89.40
1999	5,209,692	616,106	2,321,040	286,300	56,758	10,822	7,587,490	913,228	94.85
2000	5,348,845	631,106	2,321,040	286,300	56,758	10,822	7,726,643	928,228	95.02
2001	5,373,921	634,106	2,321,040	286,300	56,758	10,822	7,751,719	931,228	95.03
2002	5,394,476	636,106	2,321,040	286,300	56,758	10,822	7,772,274	933,228	95.07

"Smelter Only" Sales and Demand

	Green River (Smelter Only)		Henderson-Union (Smelter Only)		Total Non-rural		
Year	Energy (MWh)	Demand kW	Energy (MWh)	Demand kW	Energy (MWh)	Demand kW	Load Factor
1994	2,911,486	357,617	2,031,376	346,291	4,942,862	703,908	80.16
1995	3,032,739	358,220	2,130,072	232,934	5,162,811	591,154	99.70
1996	3,045,189	359,739	1,982,908	234,490	5,028,097	594,229	96.59
1997	3,069,775	363,802	1,963,110	235,000	5,032,885	598,802	95.95
1998	3,130,317	365,069	2,012,458	240,000	5,142,775	605,069	97.03
1999	3,902,580	450,000	2,052,000	236,000	5,954,580	686,000	99.09
2000	3,902,580	450,000	2,052,000	236,000	5,954,580	686,000	99.09
2001	3,902,580	450,000	2,052,000	236,000	5,954,580	686,000	99.09
2002	3,902,580	450,000	2,052,000	236,000	5,954,580	686,000	99.09

electricity. This is of particular interest due to the cooperatives' large residential consumer classification. The commercial and industrial sectors are projected to have lower annual growth rates of 1.2 and 1.3 percent per year, respectively, through 2020.

*****

PART III - UNCERTAINTY ANALYSIS

PART III

UNCERTAINTY ANALYSES

A range of forecasts based on different assumptions about the future is useful in developing flexible plans for supplying future loads. Therefore, uncertainty analyses were performed to estimate the impact of varying conditions on Big Rivers' future rural system energy requirements and peak demand. The rural system energy requirements scenarios presented in this part of the report represent the sum of the respective energy requirements scenarios developed for the member distribution cooperatives, while the rural system peak demand analyses were conducted at the G&T level. Although no attempt was made to assign probabilities of occurrence to the various scenarios, the analyses were developed to provide some indication of the range in which the forecasts could vary due to alternative input assumptions.

Two sets of scenarios were developed. In the first analysis, weather assumptions were varied from the historical averages used in Big Rivers' members' base case projections. The second analysis considered optimistic and pessimistic future economic conditions. These analyses are described below.

WEATHER UNCERTAINTY

Both energy requirements and peak demand projections were developed for scenarios that assumed severe and mild weather conditions.

Severe Weather Scenario

To project rural system energy requirements for this scenario, the historical maximum numbers of heating and cooling degree days were inserted into the residential energy sales per consumer equation for each member system. The small commercial, large commercial, and other miscellaneous classes were generally assumed to be non-weather sensitive. The severe weather energy requirements scenario is shown in Table III-1. This forecast indicates that Big Rivers' system rural energy requirements would reach 3,403,594 MWh by 2018 given the assumptions mentioned herein, which would be a 3.1 percent average annual compound growth rate over 1998.

To develop the extreme weather coincident peak demand scenario for all of the cooperatives except Meade County, the minimum load factor experienced from 1974 to 1998 was applied to the base case energy requirements forecast. The average load factor experienced from 1991 to 1998 was applied to the

Table III-1

SEVERE WEATHER SCENARIO
ENERGY SALES BY CONSUMER CLASS

Big Rivers Electric Corporation

	Year	Residential	Small Commercial	Total Large Commercial	Public Street & Highway	Total Sales	Own Use	Losses	Total Rural Energy Requirements
	1994	1,040,652	360,612	70,298	2,509	1,474,072	3,226	94,186	1,571,485
	1995	1,101,490	381,680	69,478	2,641	1,555,288	3,334	107,704	1,666,327
	1996	1,144,623	389,824	78,668	2,661	1,615,776	3,599	109,305	1,728,680
	1997	1,137,995	411,100	92,414	2,802	1,644,311	3,305	108,225	1,755,841
Historical	1998	1,199,476	427,835	111,516	2,846	1,741,673	3,439	104,647	1,849,759
Projected	1999	1,299,369 [1]	453,983	151,330	2,919	1,907,602	3,784 [2]	118,320 [3]	2,029,705
	2000	1,345,898	467,495	171,126	2,994	1,987,513	3,904	123,057	2,114,475
	2001	1,388,168	484,181	177,682	3,071	2,053,101	4,006	126,662	2,183,769
	2002	1,433,223	497,050	177,990	3,150	2,111,414	4,081	129,896	2,245,390
	2003	1,478,696	513,549	182,558	3,231	2,178,035	4,169	133,563	2,315,766
	2004	1,525,097	526,460	182,887	3,307	2,237,751	4,246	136,847	2,378,844
	2005	1,573,145	543,310	183,227	3,384	2,303,066	4,337	140,415	2,447,818
	2006	1,622,045	556,416	187,827	3,464	2,369,753	4,418	144,053	2,518,224
	2007	1,663,290	569,730	188,190	3,546	2,424,755	4,492	146,990	2,576,238
	2008	1,715,757	583,208	188,564	3,629	2,491,158	4,577	150,594	2,646,329
	2009	1,767,797	600,739	193,200	3,715	2,565,451	4,670	154,111	2,724,232
	2010	1,820,319	614,364	193,599	3,803	2,632,086	4,753	157,682	2,794,521
	2011	1,871,232	632,098	194,012	3,894	2,701,235	4,848	161,283	2,867,366
	2012	1,924,649	645,678	198,687	3,986	2,773,000	4,936	165,000	2,942,936
	2013	1,977,948	662,817	199,127	4,081	2,843,974	5,034	168,654	3,017,662
	2014	2,032,357	676,987	199,582	4,179	2,913,105	5,123	172,189	3,090,416
	2015	2,087,017	694,433	204,301	4,279	2,990,030	5,223	176,085	3,171,338
	2016	2,142,861	708,526	204,785	4,382	3,060,554	5,313	179,639	3,245,506
	2017	2,199,418	725,893	205,286	4,487	3,135,084	5,416	183,384	3,323,883
	2018	2,256,775	739,515	210,052	4,596	3,210,938	5,509	187,146	3,403,594

Average Annual Compound Growth Rates:

	Residential	Small Commercial	Total Large Commercial	Public Street & Highway	Total Sales	Own Use	Losses	Total Rural Energy Requirements
1994-1998	3.6%	4.4%	12.2%	3.2%	4.3%	1.6%	2.7%	4.2%
1998-2002	4.6%	3.8%	12.4%	2.6%	4.9%	4.4%	5.6%	5.0%
1998-2018	3.2%	2.8%	3.2%	2.4%	3.1%	2.4%	2.9%	3.1%

[1] Forecast based on maximum annual cooling degree days for the period 1979 to 1998.
[2] Borrower's Own Use is projected to be 0.29 percent of Total Rural System Energy Sales based on the weighted average of Borrower's Own Use for the period 1993 to 1998.
[3] Borrower's Losses are projected to be 5.17 percent of Total Rural System Energy Sales based on the weighted average of Borrower's Losses for the period 1993 to 1998.

severe weather scenario energy requirements forecast to develop the extreme weather coincident peak demand scenario for Meade County. These coincident peaks were then totaled to arrive at Big Rivers' coincident peak. This forecast indicates that Big Rivers' coincident peak demand would reach 811.5 MW by 2018 given the assumptions mentioned herein. This would correlate to a 3.3 percent average annual increase over 1998. The severe weather peak demand scenario is shown in Table III-2.

Mild Weather Scenario

To project rural system energy requirements for this scenario, the historical minimum numbers of heating and cooling degree days were inserted into the residential energy sales per consumer equation for each member system. The small commercial, large commercial, and other miscellaneous classes were generally assumed to be non-weather sensitive. The mild weather energy requirements scenario is shown in Table III-3. This forecast indicates that Big Rivers' rural system energy requirements would reach 3,275,741 MWh by 2018 given the assumptions mentioned herein, which would be a 2.9 percent average annual increase from 1998.

To develop the mild weather coincident peak demand scenario, the maximum load factor experienced from 1974 to 1998 for each of the cooperatives except for Meade County was applied to the base case energy requirements forecast. The average load factor experienced from 1991 to 1998 was applied to the mild weather scenario energy requirements forecast to develop the mild weather coincident peak demand scenario for Meade County. These coincident peaks were then totaled to arrive at Big Rivers' coincident peak. This forecast indicates that Big Rivers' coincident peak demand would reach 711.7 MW by 2018 given the assumptions mentioned herein. This would correlate to a 2.6 percent average annual increase over 1998. The severe weather peak demand scenario is shown in Table III-4.

ECONOMIC UNCERTAINTY

High and low scenarios for both energy requirements and peak demand were developed for each member system based on optimistic and pessimistic macroeconomic assumptions.. Most ranges for independent variables included in the uncertainty analyses were developed using the @Risk software product made by Palisade Corporation. This software provides Monte Carlo simulation capabilities that were used in this study to develop 90 percent confidence ranges of projected sustained growth in variables such as population, income and employment. The historical mean and standard deviation of annual growth in each variable were used to simulate a normal distribution of

Table III-2

SEVERE WEATHER SCENARIO
PEAK DEMAND AND LOAD FACTOR
Big Rivers Electric Corporation

		System Energy Requirements		System Peak Demand [1]		System Load Factor
	Year	(MWh)	Percent Increase	(kW)	Percent Increase	Percent
	1994	1,571,485	--	359,832	--	49.9
	1995	1,666,327	6.0%	387,914	7.8%	49.0
	1996	1,728,680	3.7%	382,214	-1.5%	51.6
	1997	1,755,841	1.6%	409,524	7.1%	48.9
Historical	1998	1,849,759	5.3%	425,035	3.8%	49.7
Projected	1999	1,993,663 [2]	7.8%	483,265 [3]	13.7%	47.1
	2000	2,077,602	4.2%	503,567	4.2%	47.1
	2001	2,145,998	3.3%	520,139	3.3%	47.1
	2002	2,206,702	2.8%	534,823	2.8%	47.1
	2003	2,276,169	3.1%	551,667	3.1%	47.1
	2004	2,338,347	2.7%	566,692	2.7%	47.1
	2005	2,406,388	2.9%	583,149	2.9%	47.1
	2006	2,475,871	2.9%	599,973	2.9%	47.1
	2007	2,532,940	2.3%	613,765	2.3%	47.1
	2008	2,602,053	2.7%	630,464	2.7%	47.1
	2009	2,678,996	3.0%	649,098	3.0%	47.1
	2010	2,748,343	2.6%	665,842	2.6%	47.1
	2011	2,820,205	2.6%	683,256	2.6%	47.1
	2012	2,894,751	2.6%	701,349	2.6%	47.1
	2013	2,968,461	2.5%	719,209	2.5%	47.1
	2014	3,040,167	2.4%	736,581	2.4%	47.1
	2015	3,120,053	2.6%	755,972	2.6%	47.1
	2016	3,193,155	2.3%	773,680	2.3%	47.1
	2017	3,270,461	2.4%	792,410	2.4%	47.1
	2018	3,349,098	2.4%	811,487	2.4%	47.1

Average Annual Compound Growth Rates:

	Energy	Peak Demand
1994-1998	4.2%	4.3%
1998-2003	4.5%	5.9%
1998-2018	3.0%	3.3%

[1] Coincident peak demand.
[2] Base case System Energy Requirements.
[3] Forecasted demand is the sum of the forecasted peak demands for the individual cooperatives.

Table III-8

PESSIMISTIC MACROECONOMIC ASSUMPTIONS SCENARIO
PEAK DEMAND AND LOAD FACTOR

Big Rivers Electric Corporation

		System Energy Requirements		System Peak Demand [1]		System Load Factor
	Year	(MWh)	Percent Increase	(kW)	Percent Increase	Percent
	1994	1,571,485	--	359,832	--	49.9
	1995	1,666,327	6.0%	387,914	7.8%	49.0
	1996	1,728,680	3.7%	382,214	-1.5%	51.6
	1997	1,755,841	1.6%	409,524	7.1%	48.9
Historical	1998	1,849,759	5.3%	425,035	3.8%	49.7
Projected	1999	1,932,180	4.5%	443,080	4.2%	49.8
	2000	1,981,423	2.5%	452,075	2.0%	50.0
	2001	2,007,429	1.3%	456,876	1.1%	50.2
	2002	2,022,853	0.8%	460,559	0.8%	50.1
	2003	2,045,767	1.1%	465,991	1.2%	50.1
	2004	2,059,817	0.7%	469,343	0.7%	50.1
	2005	2,078,073	0.9%	473,675	0.9%	50.1
	2006	2,096,126	0.9%	477,965	0.9%	50.1
	2007	2,113,482	0.8%	482,069	0.9%	50.0
	2008	2,127,525	0.7%	485,415	0.7%	50.0
	2009	2,148,586	1.0%	490,403	1.0%	50.0
	2010	2,161,015	0.6%	493,367	0.6%	50.0
	2011	2,178,130	0.8%	497,422	0.8%	50.0
	2012	2,195,620	0.8%	501,576	0.8%	50.0
	2013	2,211,998	0.7%	505,455	0.8%	50.0
	2014	2,225,196	0.6%	508,595	0.6%	49.9
	2015	2,245,689	0.9%	513,437	1.0%	49.9
	2016	2,258,346	0.6%	516,446	0.6%	49.9
	2017	2,273,955	0.7%	520,139	0.7%	49.9
	2018	2,289,689	0.7%	523,869	0.7%	49.9

Average Annual Compound Growth Rates:

	Energy	Peak Demand
1994-1998	4.2%	4.3%
1998-2002	2.3%	2.0%
1998-2018	1.1%	1.1%

[1] Coincident peak demand.

[2] Pessimistic Economic Scenario Rural System Energy Requirements.

SUMMARY OF WEATHER AND ECONOMIC UNCERTAINTY ANALYSES

The summary of the weather and economic uncertainty analyses for rural-system energy requirements is shown in Figure III-1. The figure indicates that rural system electricity sales are expected to be much more dependent on future economic conditions than year-to-year weather variation. The optimistic economic assumptions scenario calls for growth of 4.2 percent per year, with total energy requirements reaching 4,210,797 MWh by 2018. The pessimistic economic assumptions scenario calls for growth of 2.1 percent per year, with total energy requirements of approximately 2,808,213 MWh by 2018.

Figure III-2 summarizes the weather and economic uncertainty analyses for rural-system, non-coincident peak demand. The figure indicates the high level of possible year-to-year variations in peak demand as a result of weather conditions although economic conditions still show greater year-to-year variation. The optimistic economic assumption scenario shows peak demand reaching 966.4 MW by 2018, while the pessimistic economic assumptions scenario shows peak demand at approximately 523.9 MW by 2018.

* * * *

Table III-6

OPTIMISTIC MACROECONOMIC ASSUMPTIONS SCENARIO
PEAK DEMAND AND LOAD FACTOR

Big Rivers Electric Corporation

		System Energy Requirements		System Peak Demand [1]		System Load Factor
	Year	(MWh)	Percent Increase	(kW)	Percent Increase	Percent
	1994	1,571,485	--	359,832	--	49.9
	1995	1,666,327	6.0%	387,914	7.8%	49.0
	1996	1,728,680	3.7%	382,214	-1.5%	51.6
	1997	1,755,841	1.6%	409,524	7.1%	48.9
Historical	1998	1,849,759	5.3%	425,035	3.8%	49.7
Projected	1999	2,001,567 [2]	8.2%	459,134 [3]	8.0%	49.8
	2000	2,109,364	5.4%	481,558	4.9%	50.0
	2001	2,204,516	4.5%	502,090	4.3%	50.1
	2002	2,295,610	4.1%	523,144	4.2%	50.1
	2003	2,393,468	4.3%	545,790	4.3%	50.1
	2004	2,489,335	4.0%	567,949	4.1%	50.0
	2005	2,588,531	4.0%	590,894	4.0%	50.0
	2006	2,694,723	4.1%	615,465	4.2%	50.0
	2007	2,799,599	3.9%	639,713	3.9%	50.0
	2008	2,908,325	3.9%	664,865	3.9%	49.9
	2009	3,022,952	3.9%	691,407	4.0%	49.9
	2010	3,136,540	3.8%	717,683	3.8%	49.9
	2011	3,254,676	3.8%	745,026	3.8%	49.9
	2012	3,380,937	3.9%	774,265	3.9%	49.8
	2013	3,506,455	3.7%	803,321	3.8%	49.8
	2014	3,636,989	3.7%	833,532	3.8%	49.8
	2015	3,775,564	3.8%	865,627	3.9%	49.8
	2016	3,914,881	3.7%	897,872	3.7%	49.8
	2017	4,058,290	3.7%	931,074	3.7%	49.8
	2018	4,210,797	3.8%	966,390	3.8%	49.7

Average Annual Compound Growth Rates:

	Energy	Peak Demand
1994-1998	4.2%	4.3%
1998-2002	5.5%	5.3%
1998-2018	4.2%	4.2%

[1] Coincident peak demand.
[2] Optimistic Economic Scenario Rural System Energy Requirements.

Table III-7

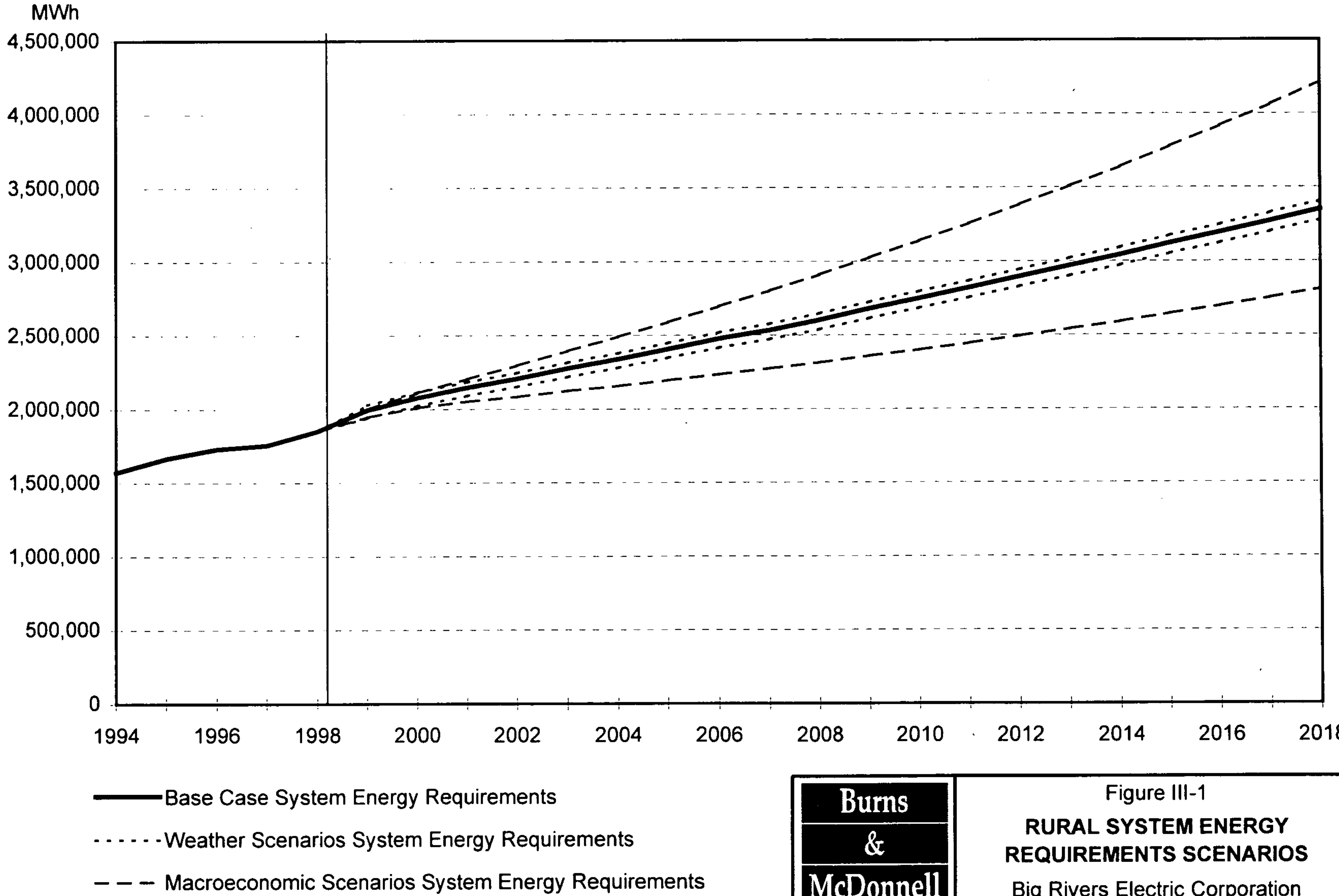
PESSIMISTIC MACROECONOMIC ASSUMPTIONS SCENARIO
ENERGY SALES BY CONSUMER CLASS
Big Rivers Electric Corporation

	Year	Residential	Small Commercial	Total Large Commercial	Public Street & Highway	Total Sales	Own Use	Losses	Total Rural Energy Requirements
	1994	1,040,652	360,612	70,298	2,509	1,474,072	3,226	94,186	1,571,485
	1995	1,101,490	381,680	69,478	2,641	1,555,288	3,334	107,704	1,666,327
	1996	1,144,623	389,824	78,668	2,661	1,615,776	3,599	109,305	1,728,680
	1997	1,137,995	411,100	92,414	2,802	1,644,311	3,305	108,225	1,755,841
Historical	1998	1,199,476	427,835	111,516	2,846	1,741,673	3,439	104,647	1,849,759
Projected	1999	1,225,113 [1]	447,917 [2]	151,050	2,904	1,826,985	3,656 [3]	114,878 [4]	1,945,519
	2000	1,253,596	460,248	170,557	2,964	1,887,366	3,739	118,100	2,009,205
	2001	1,271,533	475,527	176,814	3,027	1,926,902	3,775	119,821	2,050,498
	2002	1,290,108	487,490	176,814	3,091	1,957,503	3,782	121,070	2,082,355
	2003	1,308,817	503,472	181,064	3,157	1,996,510	3,800	122,694	2,123,003
	2004	1,327,901	516,216	181,064	3,217	2,028,398	3,806	123,856	2,156,060
	2005	1,347,985	532,991	181,064	3,278	2,065,319	3,823	125,243	2,194,385
	2006	1,368,289	546,539	185,314	3,342	2,103,484	3,830	126,629	2,233,943
	2007	1,389,509	564,151	185,314	3,407	2,142,380	3,847	127,842	2,274,069
	2008	1,411,901	578,564	185,314	3,474	2,179,252	3,854	129,056	2,312,162
	2009	1,434,431	597,087	189,563	3,543	2,224,624	3,869	130,160	2,358,653
	2010	1,457,393	612,466	189,563	3,614	2,263,037	3,873	131,271	2,398,181
	2011	1,482,107	631,995	189,563	3,686	2,307,351	3,888	132,614	2,443,854
	2012	1,507,822	648,346	193,813	3,761	2,353,742	3,895	134,021	2,491,658
	2013	1,534,326	668,933	193,813	3,838	2,400,911	3,911	135,347	2,540,169
	2014	1,562,693	686,440	193,813	3,918	2,446,864	3,917	136,507	2,587,288
	2015	1,591,539	708,199	198,063	3,999	2,501,800	3,934	138,000	2,643,734
	2016	1,622,234	726,931	198,063	4,083	2,551,310	3,939	139,114	2,694,364
	2017	1,653,615	749,924	198,063	4,169	2,605,771	3,956	140,388	2,750,115
	2018	1,686,102	769,945	202,312	4,257	2,662,618	3,963	141,632	2,808,213

Average Annual Compound Growth Rates:

	Residential	Small Commercial	Total Large Commercial	Public Street & Highway	Total Sales	Own Use	Losses	Total Rural Energy Requirements
1994-1998	3.6%	4.4%	12.2%	3.2%	4.3%	1.6%	2.7%	4.2%
1998-2002	1.8%	3.3%	12.2%	2.1%	3.0%	2.4%	3.7%	3.0%
1998-2018	1.7%	3.0%	3.0%	2.0%	2.1%	0.7%	1.5%	2.1%

[1] Residential energy requirements forecast based on average annual compound growth in population of -0.4 percent, average annual compound growth in per capita income of 0.2 percent, and average annual compound growth in residential electricity prices of 3.2 percent.
[2] Small commercial energy requirements forecast based on average annual compound growth in total employment of 0.3 percent and average annual compound growth of small commercial electricity price of 2.8 percent.
[3] Borrower's Own Use is projected to be 0.29 percent of Total Rural System Energy Sales based on the weighted average of Borrower's Own Use for the period 1993 to 1998.
[4] Borrower's Losses are projected to be 5.17 percent of Total Rural System Energy Sales based on the weighted average of Borrower's Losses for the period 1993 to 1998.

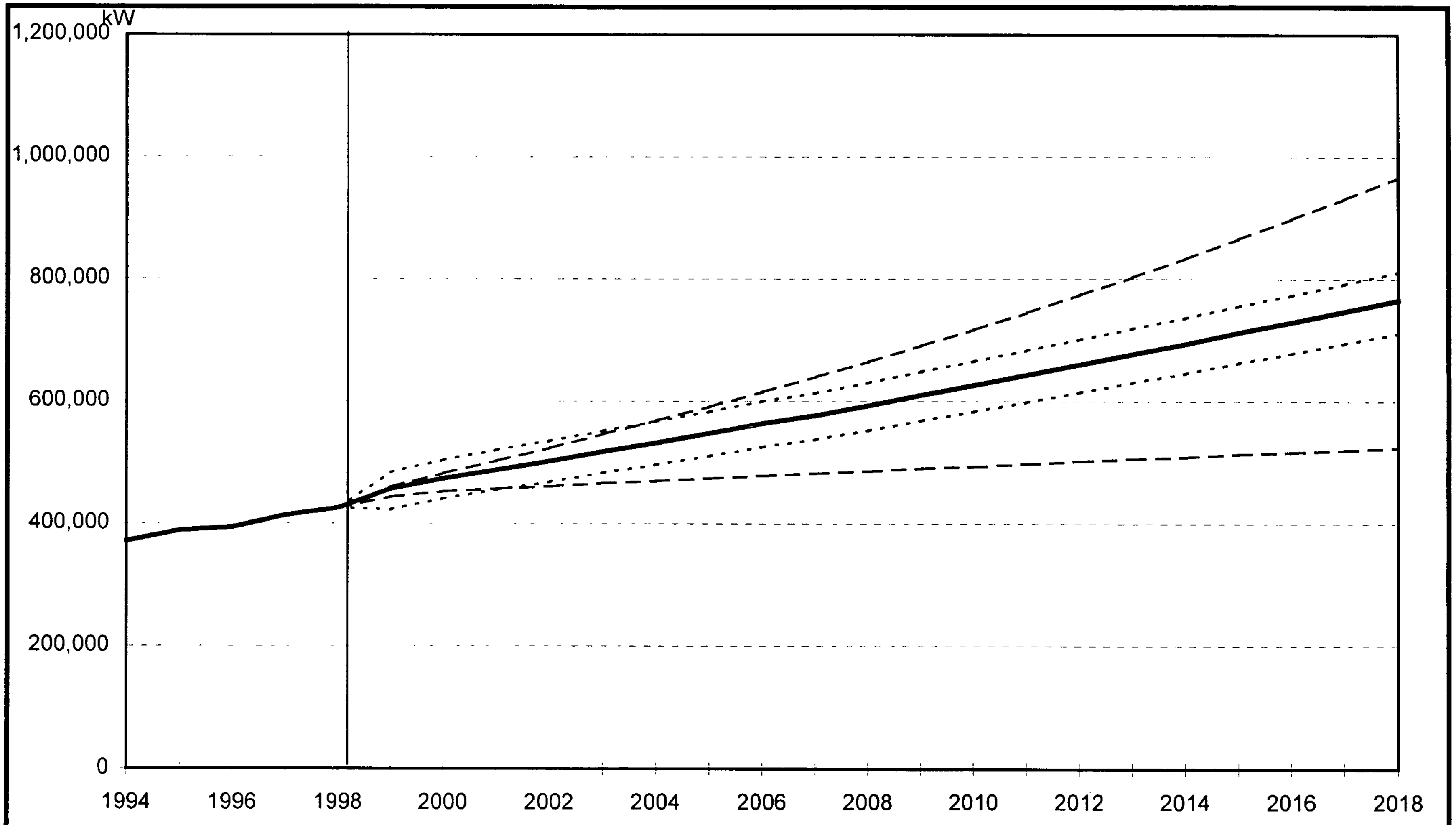


Burns & McDonnell

Figure III-1

RURAL SYSTEM ENERGY REQUIREMENTS SCENARIOS

Big Rivers Electric Corporation



Base Case Non-Coincident Peak Demand

Weather Scenarios Non-Coincident Peak Demand

Macroeconomic Scenarios Non-Coincident Peak Demand

Burns & McDonnell

Figure III-2
RURAL SYSTEM DEMAND SCENARIOS
Big Rivers Electric Corporation

APPENDIX A – DATA SOURCES

Appendix B

Screening Analysis

7FA

7FA Simple Cycle Combustion Turbine [1]

Big Rivers Electric Corporation

Unit:	7FA [1]	
Size:	169	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	3.71	($/kW-Yr.)
VO&M:	3.88	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	10,500	(Btu/kWh)
Installed Cost:	316	($/kW)
Discount Rate:	6.0%	
Losses:	0.0%	
Yearly Cost:	27.34	($/kW)
Amortization Period	20	Years
Inflation	3.5%	

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	27.34	30.30	3.71	3.88	0.00	31.05	34.18
3.11	2000	27.34	32.65	3.84	4.02	0.00	31.18	36.66
3.14	2001	27.34	32.93	3.98	4.16	0.00	31.32	37.08
3.20	2002	27.34	33.60	4.12	4.30	0.00	31.46	37.90
3.28	2003	27.34	34.47	4.26	4.45	0.00	31.60	38.92
3.36	2004	27.34	35.26	4.41	4.61	0.00	31.75	39.87
3.44	2005	27.34	36.15	4.56	4.77	0.00	31.91	40.92
3.53	2006	27.34	37.03	4.72	4.94	0.00	32.06	41.97
3.60	2007	27.34	37.85	4.89	5.11	0.00	32.23	42.95
3.64	2008	27.34	38.23	5.06	5.29	0.00	32.40	43.52
3.67	2009	27.34	38.52	5.24	5.47	0.00	32.58	43.99
3.69	2010	27.34	38.70	5.42	5.66	0.00	32.76	44.36
3.72	2011	27.34	39.07	5.61	5.86	0.00	32.95	44.93
3.75	2012	27.34	39.34	5.81	6.07	0.00	33.15	45.41
3.74	2013	27.34	39.32	6.01	6.28	0.00	33.35	45.60
3.76	2014	27.34	39.46	6.22	6.50	0.00	33.56	45.96
3.79	2015	27.34	39.83	6.44	6.73	0.00	33.78	46.56
3.83	2016	27.34	40.20	6.66	6.96	0.00	34.00	47.16
3.86	2017	27.34	40.56	6.90	7.21	0.00	34.24	47.77
3.88	2018	27.34	40.70	7.14	7.46	0.00	34.48	48.16
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.55%	1.82%
						NPV [8]	369.97	474.60
						20 Yr. Levelized Cost	32.26	41.38

[1] All costs based on the 7FA simple cycle combustion turbine. Installed cost of $316/kW.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

7FA Combined Cycle Combustion Turbine [1]

Big Rivers Electric Corporation

Unit:	7FA [1]
Size:	520 (MW)
Unit Life:	30 Years
Base Fuel Cost:	2.89 ($/mmBtu)
Site Fuel Adder:	0.00%
Fuel Btu/Unit	1,022 (Btu/cu. ft.)
FO&M:	5.50 ($/kW-Yr.)
VO&M:	3.52 ($/MWh)
SO2	0 (lb/mmBtu)
SO2 Allowance Cost	200 ($/Ton)
NOx	0.032 (lb/mmBtu)
CO2	120 (lb/mmBtu)
CO2 Tax:	0 ($/Ton)
Particulate	0 (lb/mmBtu)
Heat Rate:	7,000 (Btu/kWh)
Construction Cost:	425 ($/kW)
Discount Rate:	6.00%
Transmission Cost:	0.00 ($/kW-Yr.)
Losses:	0.0%
Yearly Cost:	30.71 ($/kW)
Amortization Period	20 Years
Inflation	3.5%

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	30.71	20.20	5.50	3.52	0.00	36.21	23.72
3.11	2000	30.71	21.76	5.69	3.64	0.00	36.41	25.41
3.14	2001	30.71	21.95	5.89	3.77	0.00	36.60	25.72
3.20	2002	30.71	22.40	6.10	3.90	0.00	36.81	26.30
3.28	2003	30.71	22.98	6.31	4.04	0.00	37.02	27.02
3.36	2004	30.71	23.51	6.53	4.18	0.00	37.25	27.69
3.44	2005	30.71	24.10	6.76	4.33	0.00	37.47	28.42
3.53	2006	30.71	24.69	7.00	4.48	0.00	37.71	29.17
3.60	2007	30.71	25.23	7.24	4.64	0.00	37.96	29.87
3.64	2008	30.71	25.49	7.50	4.80	0.00	38.21	30.28
3.67	2009	30.71	25.68	7.76	4.97	0.00	38.47	30.64
3.69	2010	30.71	25.80	8.03	5.14	0.00	38.74	30.94
3.72	2011	30.71	26.05	8.31	5.32	0.00	39.02	31.37
3.75	2012	30.71	26.23	8.60	5.51	0.00	39.31	31.73
3.74	2013	30.71	26.21	8.90	5.70	0.00	39.62	31.91
3.76	2014	30.71	26.31	9.21	5.90	0.00	39.93	32.21
3.79	2015	30.71	26.55	9.54	6.10	0.00	40.25	32.66
3.83	2016	30.71	26.80	9.87	6.32	0.00	40.58	33.12
3.86	2017	30.71	27.04	10.22	6.54	0.00	40.93	33.58
3.88	2018	30.71	34.13	10.57	6.77	0.00	41.29	40.90
	Average Annual Escalation:		2.80%	3.50%	3.50%	#DIV/0!	0.69%	2.91%
						NPV [8]	435.78	332.75
						20 Yr. Levelized Cost	37.99	29.01

[1] All costs based on the 7FA combined cycle combustion turbine. Installed cost of $425/kW including IDC
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Table III-3

MILD WEATHER SCENARIO
ENERGY SALES BY CONSUMER CLASS

Big Rivers Electric Corporation

	Year	Residential	Small Commercial	Total Large Commercial	Public Street & Highway	Total Sales	Own Use	Losses	Total Rural Energy Requirements
	1994	1,040,652	360,612	70,298	2,509	1,474,072	3,226	94,186	1,571,485
	1995	1,101,490	381,680	69,478	2,641	1,555,288	3,334	107,704	1,666,327
	1996	1,144,623	389,824	78,668	2,661	1,615,776	3,599	109,305	1,728,680
	1997	1,137,995	411,100	92,414	2,802	1,644,311	3,305	108,225	1,755,841
Historical	1998	1,199,476	427,835	111,516	2,846	1,741,673	3,439	104,647	1,849,759
Projected	1999	1,212,724 [1]	453,983	151,330	2,919	1,820,956	3,720 [2]	116,100 [3]	1,940,776
	2000	1,257,200	467,495	171,126	2,994	1,898,815	3,839	120,774	2,023,428
	2001	1,297,482	484,181	177,682	3,071	1,962,415	3,939	124,323	2,090,676
	2002	1,340,543	497,050	177,990	3,150	2,018,734	4,013	127,500	2,150,247
	2003	1,384,046	513,549	182,558	3,231	2,083,384	4,099	131,110	2,218,594
	2004	1,428,498	526,460	182,887	3,307	2,141,152	4,175	134,337	2,279,664
	2005	1,474,541	543,310	183,227	3,384	2,204,463	4,264	137,847	2,346,574
	2006	1,521,461	556,416	187,827	3,464	2,269,169	4,344	141,427	2,414,940
	2007	1,560,687	569,730	188,190	3,546	2,322,153	4,417	144,306	2,470,875
	2008	1,611,088	583,208	188,564	3,629	2,386,489	4,500	147,850	2,538,839
	2009	1,661,092	600,739	193,200	3,715	2,458,746	4,592	151,310	2,614,648
	2010	1,711,608	614,364	193,599	3,803	2,523,374	4,674	154,825	2,682,873
	2011	1,760,581	632,098	194,012	3,894	2,590,585	4,767	158,380	2,753,732
	2012	1,812,038	645,678	198,687	3,986	2,660,390	4,854	162,050	2,827,294
	2013	1,863,399	662,817	199,127	4,081	2,729,424	4,951	165,658	2,900,033
	2014	1,915,801	676,987	199,582	4,179	2,796,549	5,038	169,145	2,970,732
	2015	1,968,495	694,433	204,301	4,279	2,871,508	5,138	172,994	3,049,639
	2016	2,022,323	708,526	204,785	4,382	2,940,016	5,226	176,499	3,121,742
	2017	2,076,880	725,893	205,286	4,487	3,012,546	5,328	180,196	3,198,070
	2018	2,132,248	739,515	210,052	4,596	3,086,411	5,420	183,909	3,275,741

Average Annual Compound Growth Rates:

	Residential	Small Commercial	Total Large Commercial	Public Street & Highway	Total Sales	Own Use	Losses	Total Rural Energy Requirements
1994-1998	3.6%	4.4%	12.2%	3.2%	4.3%	1.6%	2.7%	4.2%
1998-2002	2.8%	3.8%	12.4%	2.6%	3.8%	3.9%	5.1%	3.8%
1998-2018	2.9%	2.8%	3.2%	2.4%	2.9%	2.3%	2.9%	2.9%

[1] Forecast based on maximum annual cooling degree days for the period 1979 to 1998.

[2] Borrower's Own Use is projected to be 0.29 percent of Total Rural System Energy Sales based on the weighted average of Borrower's Own Use for the period 1993 to 1998.

[3] Borrower's Losses are projected to be 5.17 percent of Total Rural System Energy Sales based on the weighted average of Borrower's Losses for the period 1993 to 1998.

Table III-4

MILD WEATHER SCENARIO
PEAK DEMAND AND LOAD FACTOR
Big Rivers Electric Corporation

		System Energy Requirements		System Peak Demand [1]		System Load Factor
	Year	(MWh)	Percent Increase	(kW)	Percent Increase	Percent
	1994	1,571,485	--	359,832	--	49.9
	1995	1,666,327	6.0%	387,914	7.8%	49.0
	1996	1,728,680	3.7%	382,214	-1.5%	51.6
	1997	1,755,841	1.6%	409,524	7.1%	48.9
Historical	1998	1,849,759	5.3%	425,035	3.8%	49.7
Projected	1999	1,978,431 [2]	7.0%	422,710 [3]	-0.5%	53.4
	2000	2,061,844	4.2%	440,565	4.2%	53.4
	2001	2,129,822	3.3%	455,113	3.3%	53.4
	2002	2,190,099	2.8%	468,054	2.8%	53.4
	2003	2,259,132	3.2%	482,843	3.2%	53.4
	2004	2,320,868	2.7%	496,111	2.7%	53.4
	2005	2,388,462	2.9%	510,618	2.9%	53.4
	2006	2,457,488	2.9%	525,434	2.9%	53.4
	2007	2,514,092	2.3%	537,587	2.3%	53.4
	2008	2,582,734	2.7%	552,343	2.7%	53.4
	2009	2,659,197	3.0%	568,749	3.0%	53.4
	2010	2,728,055	2.6%	583,565	2.6%	53.4
	2011	2,799,581	2.6%	598,887	2.6%	53.4
	2012	2,873,788	2.7%	614,775	2.7%	53.4
	2013	2,947,153	2.6%	630,489	2.6%	53.4
	2014	3,018,511	2.4%	645,788	2.4%	53.4
	2015	3,098,044	2.6%	662,808	2.6%	53.4
	2016	3,170,789	2.3%	678,405	2.4%	53.4
	2017	3,247,734	2.4%	694,889	2.4%	53.4
	2018	3,326,005	2.4%	711,654	2.4%	53.4

Average Annual Compound Growth Rates:

	Energy	Peak Demand
1994-1998	4.2%	4.3%
1998-2002	4.3%	2.4%
1998-2018	3.0%	2.6%

[1] Coincident peak demand.
[2] Base case System Energy Requirements.
[3] Forecasted demand is the sum of the forecasted peak demands for the individual cooperatives.

expected growth rates. Using the output describing this distribution, the growth rate that marks the top 5 percent of possible growth rates and the growth rate that marks the bottom 5 percent of possible growth rates were ascertained for each independent variable. These projected high and low growth rates were used to replace the independent variables in the original econometric models, and thus generate appropriate confidence intervals.

Optimistic Macroeconomic Assumptions

The results of the rural system optimistic economic scenario for energy requirements is shown in Table III-5. This forecast indicates Big Rivers' system energy requirements would reach 4,210,797 MWh by 2018 given the assumptions discussed in the member reports. This equates to average annual growth of 4.2 percent.

To develop the corresponding peak demand scenario, the base case system load factor forecast for each of the cooperatives was applied to the optimistic macroeconomics energy requirements forecast. These coincident peaks were then totaled to arrive at Big Rivers' coincident peak. This forecast indicates that Big Rivers' coincident peak demand would reach 966.4 MW by 2018 given the assumptions mentioned herein. This would correlate to a 4.2 percent average annual increase over 1998. The severe weather peak demand scenario is shown in Table III-6.

Pessimistic Macroeconomic Assumptions

The results of the rural system pessimistic economic scenario for energy requirements is shown in Table III-7. This forecast indicates Big Rivers' system energy requirements would be approximately 2,808,213 MWh by 2018 given the assumptions discussed in the member reports. This equates to average annual growth of 2.1 percent.

To develop the corresponding peak demand scenario, the base case system load factor forecast for each of the cooperatives was applied to the pessimistic macroeconomics energy requirements forecast. These coincident peaks were then totaled to arrive at Big Rivers' coincident peak. This forecast indicates that Big Rivers' coincident peak demand would reach 523.9 MW by 2018 given the assumptions mentioned herein. This would correlate to a 1.1 percent average annual increase over 1998. The severe weather peak demand scenario is shown in Table III-8.

Table III-5

OPTIMISTIC MACROECONOMIC ASSUMPTIONS SCENARIO
ENERGY SALES BY CONSUMER CLASS

Big Rivers Electric Corporation

	Year	Residential	Small Commercial	Total Large Commercial	Public Street & Highway	Total Sales	Own Use	Losses	Total Rural Energy Requirements
	1994	1,040,652	360,612	70,298	2,509	1,474,072	3,226	94,186	1,571,485
	1995	1,101,490	381,680	69,478	2,641	1,555,288	3,334	107,704	1,666,327
	1996	1,144,623	389,824	78,668	2,661	1,615,776	3,599	109,305	1,728,680
	1997	1,137,995	411,100	92,414	2,802	1,644,311	3,305	108,225	1,755,841
Historical	1998	1,199,476	427,835	111,516	2,846	1,741,673	3,439	104,647	1,849,759
Projected	1999	1,269,932 [1]	455,638 [2]	151,596	2,922	1,880,088	3,754 [3]	117,724 [4]	2,001,567
	2000	1,328,968	478,595	171,683	3,000	1,982,247	3,896	123,221	2,109,364
	2001	1,390,009	501,217	178,558	3,081	2,072,865	4,012	127,639	2,204,516
	2002	1,452,712	524,536	179,215	3,164	2,159,627	4,112	131,871	2,295,610
	2003	1,516,879	548,573	184,164	3,249	2,252,865	4,214	136,389	2,393,468
	2004	1,582,694	573,350	184,907	3,328	2,344,280	4,316	140,739	2,489,335
	2005	1,650,880	598,891	185,699	3,410	2,438,880	4,421	145,230	2,588,531
	2006	1,720,671	625,222	190,791	3,494	2,540,177	4,528	150,019	2,694,723
	2007	1,792,773	652,366	191,687	3,580	2,640,405	4,636	154,558	2,799,599
	2008	1,867,513	680,352	192,640	3,668	2,744,174	4,747	159,404	2,908,325
	2009	1,943,196	709,208	197,904	3,758	2,854,067	4,855	164,031	3,022,952
	2010	2,020,807	738,963	198,983	3,851	2,962,604	4,963	168,972	3,136,540
	2011	2,101,794	769,647	200,132	3,946	3,075,519	5,074	174,083	3,254,676
	2012	2,185,232	801,293	205,603	4,044	3,196,172	5,189	179,575	3,380,937
	2013	2,271,235	833,933	206,903	4,145	3,316,216	5,304	184,934	3,506,455
	2014	2,360,973	867,603	208,287	4,248	3,441,110	5,421	190,458	3,636,989
	2015	2,453,050	902,338	214,008	4,353	3,573,749	5,541	196,274	3,775,564
	2016	2,548,952	938,177	215,574	4,462	3,707,164	5,661	202,055	3,914,881
	2017	2,647,566	975,157	217,240	4,573	3,844,537	5,784	207,969	4,058,290
	2018	2,749,406	1,013,320	223,263	4,688	3,990,677	5,910	214,211	4,210,797

Average Annual Compound Growth Rates:

	Residential	Small Commercial	Total Large Commercial	Public Street & Highway	Total Sales	Own Use	Losses	Total Rural Energy Requirements
1994-1998	3.6%	4.4%	12.2%	3.2%	4.3%	1.6%	2.7%	4.2%
1998-2002	4.9%	5.2%	12.6%	2.7%	5.5%	4.6%	6.0%	5.5%
1998-2018	4.2%	4.4%	3.5%	2.5%	4.2%	2.7%	3.6%	4.2%

[1] Residential energy requirements forecast based on average annual compound growth in population of 0.9 percent, average annual compound growth in per capita income of 1.8 percent, and average annual compound growth in residential electricity prices of -5.2 percent.

[2] Small commercial energy requirements forecast based on average annual compound growth in total employment of 1.9 percent and average annual compound growth of small commercial electricity price of -5.2 percent.

[3] Borrower's Own Use is projected to be 0.29 percent of Total Rural System Energy Sales based on the weighted average of Borrower's Own Use for the period 1993 to 1998.

[4] Borrower's Losses are projected to be 5.17 percent of Total Rural System Energy Sales based on the weighted average of Borrower's Losses for the period 1993 to 1998.

Allison 5.025 MW Combustion Turbine

Unit:	Allison 5.025 MW CT [1]
Size:	5.025 (MW)
Unit Life:	30 Years
Base Fuel Cost:	2.89 ($/mmBtu)
Site Fuel Adder:	0.00%
Fuel Btu/Unit	1,022 (Btu/cu. ft.)
FO&M:	8.37 ($/kW-Yr.)
VO&M:	4.50 ($/MWh)
SO2	0 (lb/mmBtu)
SO2 Allowance Cost:	200 ($/Ton)
NOx	0.032 (lb/mmBtu)
CO2	120 (lb/mmBtu)
CO2 Tax:	0 ($/Ton)
Particulate	0 (lb/mmBtu)
Heat Rate:	12,533 (Btu/kWh)
Installed Cost:	616 ($/kW)
Discount Rate:	6.0%
Transmission Cost:	0.00 ($/kW-Yr.)
Losses:	0.0%
Yearly Cost:	53.29 ($/kW)
Amortization Period	20 Years
Inflation	3.5%
MMBtu/Day @ 30% CF	453

Allison 5.025 MW Combustion Turbine [1]

Big Rivers Electric Corporation

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	53.29	36.17	8.66	4.66	0.00	61.95	40.83
3.11	2000	53.29	38.97	8.97	4.82	0.00	62.26	43.79
3.14	2001	53.29	39.30	9.28	4.99	0.00	62.57	44.29
3.20	2002	53.29	40.11	9.60	5.16	0.00	62.89	45.27
3.28	2003	53.29	41.14	9.94	5.34	0.00	63.23	46.48
3.36	2004	53.29	42.09	10.29	5.53	0.00	63.58	47.62
3.44	2005	53.29	43.15	10.65	5.73	0.00	63.94	48.87
3.53	2006	53.29	44.20	11.02	5.93	0.00	64.31	50.13
3.60	2007	53.29	45.17	11.41	6.13	0.00	64.70	51.31
3.64	2008	53.29	45.63	11.81	6.35	0.00	65.10	51.98
3.67	2009	53.29	45.97	12.22	6.57	0.00	65.51	52.54
3.69	2010	53.29	46.19	12.65	6.80	0.00	65.94	52.99
3.72	2011	53.29	46.64	13.09	7.04	0.00	66.38	53.67
3.75	2012	53.29	46.96	13.55	7.28	0.00	66.84	54.24
3.74	2013	53.29	46.93	14.02	7.54	0.00	67.31	54.47
3.76	2014	53.29	47.10	14.51	7.80	0.00	67.80	54.91
3.79	2015	53.29	47.54	15.02	8.08	0.00	68.31	55.62
3.83	2016	53.29	47.98	15.55	8.36	0.00	68.84	56.34
3.86	2017	53.29	48.42	16.09	8.65	0.00	69.38	57.07
3.88	2018	53.29	48.58	16.65	8.95	0.00	69.94	57.53
		Average Annual Escala	1.56%	3.50%	3.50%		0.64%	1.82%
						NPV [8]	742.76	566.89
						20 Yr. Levelized Cost	64.76	49.42

[1] All costs based on the Allison 501-KB7 combustion turbine genset. Installed cost of $616/kW including IDC.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Allison 7.814 MW Combustion Turbine

Unit:	Allison 7.814 MW CT [1]	
Size:	7.814	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	8.37	($/kW-Yr.)
VO&M:	4.50	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	9,625	(Btu/kWh)
Installed Cost:	582	($/kW)
Discount Rate:	6.0%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	50.35	($/kW)
Amortization Period	20	Years
Inflation	3.5%	
MMBtu/Day @ 30% CF	542	

Allison 7.814 MW Combustion Turbine [1]

Big Rivers Electric Corporation

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	50.35	27.78	8.66	4.66	0.00	59.01	32.44
3.11	2000	50.35	29.93	8.97	4.82	0.00	59.32	34.75
3.14	2001	50.35	30.18	9.28	4.99	0.00	59.63	35.17
3.20	2002	50.35	30.80	9.60	5.16	0.00	59.95	35.96
3.28	2003	50.35	31.59	9.94	5.34	0.00	60.29	36.94
3.36	2004	50.35	32.32	10.29	5.53	0.00	60.64	37.85
3.44	2005	50.35	33.13	10.65	5.73	0.00	61.00	38.86
3.53	2006	50.35	33.95	11.02	5.93	0.00	61.37	39.87
3.60	2007	50.35	34.69	11.41	6.13	0.00	61.76	40.82
3.64	2008	50.35	35.04	11.81	6.35	0.00	62.16	41.39
3.67	2009	50.35	35.31	12.22	6.57	0.00	62.57	41.88
3.69	2010	50.35	35.47	12.65	6.80	0.00	63.00	42.27
3.72	2011	50.35	35.81	13.09	7.04	0.00	63.44	42.85
3.75	2012	50.35	36.06	13.55	7.28	0.00	63.90	43.35
3.74	2013	50.35	36.04	14.02	7.54	0.00	64.37	43.58
3.76	2014	50.35	36.17	14.51	7.80	0.00	64.86	43.98
3.79	2015	50.35	36.51	15.02	8.08	0.00	65.37	44.59
3.83	2016	50.35	36.85	15.55	8.36	0.00	65.90	45.21
3.86	2017	50.35	37.18	16.09	8.65	0.00	66.44	45.83
3.88	2018	50.35	37.31	16.65	8.95	0.00	67.00	46.26
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.67%	1.89%
						NPV [8]	709.04	451.76
						20 Yr. Levelized Cost	61.82	39.39

[1] All costs based on the Allison 501-KH7 combustion turbine genset. Installed cost of $582/kW including IDC.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Solar 10 MW

10.4 MW Combustion Turbine [1]

Big Rivers Electric Corporation

Unit:	Solar 10 MW [1]	
Size:	10.439	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	5.23	($/kW-Yr.)
VO&M:	13.00	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	10,515	(Btu/kWh)
Installed Cost:	746	($/kW)
Discount Rate:	6.0%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	64.57	($/kW)
Amortization Period	20	Years
Inflation	3.5%	
MMBtu/Day @ 30% CF	790	

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	64.57	30.35	5.41	13.46	0.00	69.99	43.80
3.11	2000	64.57	32.69	5.60	13.93	0.00	70.18	46.62
3.14	2001	64.57	32.97	5.80	14.41	0.00	70.37	47.39
3.20	2002	64.57	33.65	6.00	14.92	0.00	70.57	48.57
3.28	2003	64.57	34.51	6.21	15.44	0.00	70.79	49.95
3.36	2004	64.57	35.31	6.43	15.98	0.00	71.00	51.29
3.44	2005	64.57	36.20	6.65	16.54	0.00	71.23	52.74
3.53	2006	64.57	37.09	6.89	17.12	0.00	71.46	54.20
3.60	2007	64.57	37.90	7.13	17.72	0.00	71.70	55.62
3.64	2008	64.57	38.29	7.38	18.34	0.00	71.95	56.62
3.67	2009	64.57	38.57	7.64	18.98	0.00	72.21	57.55
3.69	2010	64.57	38.75	7.90	19.64	0.00	72.48	58.39
3.72	2011	64.57	39.13	8.18	20.33	0.00	72.75	59.46
3.75	2012	64.57	39.40	8.47	21.04	0.00	73.04	60.44
3.74	2013	64.57	39.37	8.76	21.78	0.00	73.34	61.15
3.76	2014	64.57	39.52	9.07	22.54	0.00	73.64	62.06
3.79	2015	64.57	39.89	9.39	23.33	0.00	73.96	63.22
3.83	2016	64.57	40.25	9.71	24.15	0.00	74.29	64.40
3.86	2017	64.57	40.62	10.05	24.99	0.00	74.63	65.61
3.88	2018	64.57	40.76	10.41	25.87	0.00	74.98	66.62
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.36%	2.23%
						NPV [8]	822.84	620.57
						20 Yr. Levelized Cost	71.74	54.10

[1] All costs based on the Solar 10 MW combustion turbine. Installed cost of $746/kW including IDC.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

AlliedSignal

AlliedSignal Microturbines [1]

Big Rivers Electric Corporation

Unit:	AlliedSignal [1]	
Size:	0.075	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	0.00	($/kW-Yr.)
VO&M:	3.00	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0	(lb/mmBtu)
CO2	0	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	13,300	(Btu/kWh)
Installed Cost:	866	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	74.94	($/kW)
Amortization Period	20	Years
Inflation	3.5%	
MMBtu/Day @ 30% CF	7	

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	74.94	38.39	0.00	3.11	0.00	74.94	41.49
3.11	2000	74.94	41.35	0.00	3.21	0.00	74.94	44.56
3.14	2001	74.94	41.71	0.00	3.33	0.00	74.94	45.03
3.20	2002	74.94	42.56	0.00	3.44	0.00	74.94	46.00
3.28	2003	74.94	43.66	0.00	3.56	0.00	74.94	47.22
3.36	2004	74.94	44.66	0.00	3.69	0.00	74.94	48.35
3.44	2005	74.94	45.79	0.00	3.82	0.00	74.94	49.60
3.53	2006	74.94	46.91	0.00	3.95	0.00	74.94	50.86
3.60	2007	74.94	47.94	0.00	4.09	0.00	74.94	52.03
3.64	2008	74.94	48.43	0.00	4.23	0.00	74.94	52.66
3.67	2009	74.94	48.79	0.00	4.38	0.00	74.94	53.17
3.69	2010	74.94	49.01	0.00	4.53	0.00	74.94	53.55
3.72	2011	74.94	49.49	0.00	4.69	0.00	74.94	54.18
3.75	2012	74.94	49.83	0.00	4.86	0.00	74.94	54.69
3.74	2013	74.94	49.80	0.00	5.03	0.00	74.94	54.83
3.76	2014	74.94	49.99	0.00	5.20	0.00	74.94	55.19
3.79	2015	74.94	50.45	0.00	5.38	0.00	74.94	55.84
3.83	2016	74.94	50.92	0.00	5.57	0.00	74.94	56.49
3.86	2017	74.94	51.38	0.00	5.77	0.00	74.94	57.15
3.88	2018	74.94	51.55	0.00	5.97	0.00	74.94	57.52
	Average Annual Escalation:		1.56%		3.50%		0.00%	1.73%
						NPV [8]	859.52	573.68
						20 Yr. Levelized Cost	74.94	50.02

[1] All costs based on a 0.075 MW Allied Signal microturbine. Installed cost of $866/kW based on information from the manufacturer.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Phosphoric Acid Fuel Cells

Unit:	Phosphoric Acid Fuel Cells	
Size:	0.2	(MW)
Unit Life:	30	Years
Base Fuel Cost:	4.25	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	0.00	($/kW-Yr.)
VO&M:	15.00	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0	(lb/mmBtu)
CO2	0	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	9,435	(Btu/kWh)
Installed Cost:	1,500	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	129.79	($/kW)
Inflation	3.5%	
Stack Replacement	61.20	($/kW)
MMBtu/Day @ 30% CF	14	
Amortization Period	20	Years

Phosphoric Acid Fuel Cells [1]

Big Rivers Electric Corporation

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
4.25	1999	190.99	40.10	0.00	15.53	0.00	190.99	55.62
4.43	2000	190.99	41.78	0.00	16.07	0.00	190.99	57.85
4.61	2001	190.99	43.54	0.00	16.63	0.00	190.99	60.17
4.81	2002	190.99	45.37	0.00	17.21	0.00	190.99	62.58
5.01	2003	190.99	47.27	0.00	17.82	0.00	190.99	65.09
5.22	2004	190.99	49.26	0.00	18.44	0.00	190.99	67.70
5.44	2005	190.99	51.33	0.00	19.08	0.00	190.99	70.41
5.67	2006	190.99	53.48	0.00	19.75	0.00	190.99	73.23
5.91	2007	190.99	55.73	0.00	20.44	0.00	190.99	76.17
6.15	2008	190.99	58.07	0.00	21.16	0.00	190.99	79.23
6.41	2009	190.99	60.51	0.00	21.90	0.00	190.99	82.41
6.68	2010	190.99	63.05	0.00	22.67	0.00	190.99	85.71
6.96	2011	190.99	65.70	0.00	23.46	0.00	190.99	89.16
7.26	2012	190.99	68.46	0.00	24.28	0.00	190.99	92.74
7.56	2013	190.99	71.33	0.00	25.13	0.00	190.99	96.46
7.88	2014	190.99	74.33	0.00	26.01	0.00	190.99	100.34
8.21	2015	190.99	77.45	0.00	26.92	0.00	190.99	104.37
8.55	2016	190.99	80.70	0.00	27.86	0.00	190.99	108.56
8.91	2017	190.99	84.09	0.00	28.84	0.00	190.99	112.93
9.29	2018	190.99	87.62	0.00	29.85	0.00	190.99	117.47
	Average Annual Escalation:		4.20%		3.50%		0.00%	4.01%
						NPV [8]	2,190.63	881.83
						20 Yr. Levelized Cost	190.99	76.88

[1] All costs based on a 0.2 MW phosphoric acid fuel cell. Installed cost of $1,500/kW.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Cat 820 kW Engine

Unit:	Cat 820 kW Engine [1]	
Size:	820	(kW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/gal)
FO&M:	6.70	($/kW-Yr.)
VO&M:	11.00	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.31	(lb/mmBtu)
CO2	0.40	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	9,868	(Btu/kWh)
Installed Cost:	758	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	65.57	($/kW)
Amortization Period	20	Years
Inflation	3.5%	
MMBtu/Day @ 30% C	58	

Cat 820 kW Engine [1]

Big Rivers Electric Corporation

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	65.57	28.48	6.70	11.00	0.00	72.27	39.48
3.11	2000	65.57	30.68	6.93	11.39	0.00	72.50	42.07
3.14	2001	65.57	30.94	7.18	11.78	0.00	72.75	42.73
3.20	2002	65.57	31.58	7.43	12.20	0.00	73.00	43.77
3.28	2003	65.57	32.39	7.69	12.62	0.00	73.26	45.01
3.36	2004	65.57	33.14	7.96	13.06	0.00	73.53	46.20
3.44	2005	65.57	33.97	8.24	13.52	0.00	73.81	47.49
3.53	2006	65.57	34.80	8.52	14.00	0.00	74.09	48.80
3.60	2007	65.57	35.57	8.82	14.48	0.00	74.39	50.05
3.64	2008	65.57	35.93	9.13	14.99	0.00	74.70	50.92
3.67	2009	65.57	36.20	9.45	15.52	0.00	75.02	51.71
3.69	2010	65.57	36.37	9.78	16.06	0.00	75.35	52.43
3.72	2011	65.57	36.72	10.12	16.62	0.00	75.69	53.34
3.75	2012	65.57	36.97	10.48	17.20	0.00	76.05	54.18
3.74	2013	65.57	36.95	10.85	17.81	0.00	76.41	54.76
3.76	2014	65.57	37.09	11.22	18.43	0.00	76.79	55.52
3.79	2015	65.57	37.43	11.62	19.07	0.00	77.19	56.51
3.83	2016	65.57	37.78	12.02	19.74	0.00	77.59	57.52
3.86	2017	65.57	38.12	12.45	20.43	0.00	78.01	58.55
3.88	2018	65.57	38.25	12.88	21.15	0.00	78.45	59.40
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.43%	2.17%
						NPV [8]	853.80	557.68
						20 Yr. Levelized Cost	74.44	48.62

[1] All costs based on the Cat 820 kW engine. Installed cost of $758/kW.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Wartsila 1.7 MW Engine

Unit:	Wartsila 1.7 MW Engine [1]	
Size:	1700	(kW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/gal)
FO&M:	0.00	($/kW-Yr.)
VO&M:	4.00	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.32	(lb/mmBtu)
CO2	0.41	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	9,669	(Btu/kWh)
Installed Cost:	547	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	47.32	($/kW)
Amortization Period	20	Years
Inflation	3.5%	
MMBtu/Day @ 30% C	118	

Wartsila 1.7 MW Engine [1]

Big Rivers Electric Corporation

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	47.32	27.91	0.00	4.14	0.00	47.32	32.05
3.11	2000	47.32	30.06	0.00	4.28	0.00	47.32	34.35
3.14	2001	47.32	30.32	0.00	4.43	0.00	47.32	34.76
3.20	2002	47.32	30.94	0.00	4.59	0.00	47.32	35.53
3.28	2003	47.32	31.74	0.00	4.75	0.00	47.32	36.49
3.36	2004	47.32	32.47	0.00	4.92	0.00	47.32	37.39
3.44	2005	47.32	33.29	0.00	5.09	0.00	47.32	38.38
3.53	2006	47.32	34.10	0.00	5.27	0.00	47.32	39.37
3.60	2007	47.32	34.85	0.00	5.45	0.00	47.32	40.30
3.64	2008	47.32	35.21	0.00	5.64	0.00	47.32	40.85
3.67	2009	47.32	35.47	0.00	5.84	0.00	47.32	41.31
3.69	2010	47.32	35.63	0.00	6.04	0.00	47.32	41.68
3.72	2011	47.32	35.98	0.00	6.26	0.00	47.32	42.23
3.75	2012	47.32	36.23	0.00	6.47	0.00	47.32	42.70
3.74	2013	47.32	36.21	0.00	6.70	0.00	47.32	42.91
3.76	2014	47.32	36.34	0.00	6.94	0.00	47.32	43.28
3.79	2015	47.32	36.68	0.00	7.18	0.00	47.32	43.86
3.83	2016	47.32	37.02	0.00	7.43	0.00	47.32	44.45
3.86	2017	47.32	37.35	0.00	7.69	0.00	47.32	45.04
3.88	2018	47.32	37.48	0.00	7.96	0.00	47.32	45.44
	Average Annual Escalation:		1.56%		3.50%		0.00%	1.85%
						NPV [8]	542.71	445.65
						20 Yr. Levelized Cost	47.32	38.85

[1] All costs based on the Wartsila 1700 kW engine. Installed cost of $547/kW.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Wartsila 4.05 MW Engine

Unit:	Wartsila 4.05 MW Engine [1]		Delivered Real Fuel Cost ($/mmBtu)
			2.89
			3.11
Size:	4050	(kW)	3.14
Unit Life:	30	Years	3.20
Base Fuel Cost:	2.89	($/mmBtu)	3.28
Site Fuel Adder:	0.00%		3.36
Fuel Btu/Unit	1,022	(Btu/gal)	3.44
FO&M:	0.00	($/kW-Yr.)	3.53
VO&M:	3.00	($/MWh)	3.60
SO2	0	(lb/mmBtu)	3.64
SO2 Allowance Cost	200	($/Ton)	3.67
NOx	0.33	(lb/mmBtu)	3.69
CO2	0.43	(lb/mmBtu)	3.72
CO2 Tax:	0	($/Ton)	3.75
Particulate	0	(lb/mmBtu)	3.74
Heat Rate:	9,290	(Btu/kWh)	3.76
Installed Cost:	831	($/kW)	3.79
Discount Rate:	6.00%		3.83
Transmission Cost:	0.00	($/kW-Yr.)	3.86
Losses:	0.0%		3.88
Yearly Cost:	111.67	($/kW)	
Amortization Period	20	Years	
Inflation	3.5%		
MMBtu/Day @ 30%	271		

Wartsila 4.05 MW Engine [1]

Big Rivers Electric Corporation

Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
1999	111.67	26.81	0.00	3.11	0.00	111.67	29.92
2000	111.67	28.88	0.00	3.21	0.00	111.67	32.10
2001	111.67	29.13	0.00	3.33	0.00	111.67	32.46
2002	111.67	29.73	0.00	3.44	0.00	111.67	33.17
2003	111.67	30.49	0.00	3.56	0.00	111.67	34.06
2004	111.67	31.20	0.00	3.69	0.00	111.67	34.88
2005	111.67	31.98	0.00	3.82	0.00	111.67	35.80
2006	111.67	32.77	0.00	3.95	0.00	111.67	36.72
2007	111.67	33.48	0.00	4.09	0.00	111.67	37.57
2008	111.67	33.83	0.00	4.23	0.00	111.67	38.06
2009	111.67	34.08	0.00	4.38	0.00	111.67	38.46
2010	111.67	34.24	0.00	4.53	0.00	111.67	38.77
2011	111.67	34.57	0.00	4.69	0.00	111.67	39.26
2012	111.67	34.81	0.00	4.86	0.00	111.67	39.66
2013	111.67	34.79	0.00	5.03	0.00	111.67	39.81
2014	111.67	34.91	0.00	5.20	0.00	111.67	40.12
2015	111.67	35.24	0.00	5.38	0.00	111.67	40.62
2016	111.67	35.56	0.00	5.57	0.00	111.67	41.14
2017	111.67	35.89	0.00	5.77	0.00	111.67	41.66
2018	111.67	36.01	0.00	5.97	0.00	111.67	41.98
Average Annual Escalation:		1.56%		3.50%		0.00%	1.80%
					NPV [8]	1,280.85	414.93
					20 Yr. Levelized Cost	111.67	36.18

[1] All costs based on the Wartsila 4050 kW engine. Installed cost of $831/kW.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Fairbanks 8.4 MW Engine

Unit:	Fairbanks 8.4 MW Engine [1]
Size:	8400 (kW)
Unit Life:	30 Years
Base Fuel Cost:	2.89 ($/mmBtu)
Site Fuel Adder:	0.00%
Fuel Btu/Unit	1,022 (Btu/gal)
FO&M:	0.00 ($/kW-Yr.)
VO&M:	3.00 ($/MWh)
SO2	0.00 (lb/mmBtu)
SO2 Allowance Cost:	200 ($/Ton)
NOx	0.34 (lb/mmBtu)
CO2	0.54 (lb/mmBtu)
CO2 Tax:	0 ($/Ton)
Particulate	0.05 (lb/mmBtu)
Heat Rate:	9,122 (Btu/kWh)
Installed Cost:	914 ($/kW)
Discount Rate:	6.00%
Transmission Cost:	0.00 ($/kW-Yr.)
Losses:	0.0%
Yearly Cost:	79.08 ($/kW)
Amortization Period	20 Years
Inflation	3.5%
MMBtu/Day @ 30% CF	552

Fairbanks 8.4 MW Engine [1]

Big Rivers Electric Corporation

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	79.08	26.33	0.00	3.11	0.00	79.08	29.44
3.11	2000	79.08	28.36	0.00	3.21	0.00	79.08	31.58
3.14	2001	79.08	28.60	0.00	3.33	0.00	79.08	31.94
3.20	2002	79.08	29.19	0.00	3.44	0.01	79.08	32.64
3.28	2003	79.08	29.94	0.00	3.56	0.01	79.08	33.51
3.36	2004	79.08	30.63	0.00	3.69	0.01	79.08	34.32
3.44	2005	79.08	31.40	0.00	3.82	0.01	79.08	35.22
3.53	2006	79.08	32.17	0.00	3.95	0.01	79.08	36.13
3.60	2007	79.08	32.88	0.00	4.09	0.01	79.08	36.97
3.64	2008	79.08	33.21	0.00	4.23	0.01	79.08	37.45
3.67	2009	79.08	33.46	0.00	4.38	0.01	79.08	37.85
3.69	2010	79.08	33.62	0.00	4.53	0.01	79.08	38.16
3.72	2011	79.08	33.94	0.00	4.69	0.01	79.08	38.64
3.75	2012	79.08	34.18	0.00	4.86	0.01	79.08	39.04
3.74	2013	79.08	34.16	0.00	5.03	0.01	79.08	39.19
3.76	2014	79.08	34.28	0.00	5.20	0.01	79.08	39.49
3.79	2015	79.08	34.60	0.00	5.38	0.01	79.08	39.99
3.83	2016	79.08	34.92	0.00	5.57	0.01	79.08	40.50
3.86	2017	79.08	35.24	0.00	5.77	0.01	79.08	41.01
3.88	2018	79.08	35.36	0.00	5.97	0.01	79.08	41.33
	Average Annual Escalation:		1.56%		3.50%	3.50%	0.00%	1.80%
						NPV [8]	907.05	408.34
						20 Yr. Levelized Cost	79.08	35.60

[1] All costs based on the Fairbanks-Morse 18PC2.5V, 8.4 MW engine. Installed cost of $914/kW.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

LM1600 CT

15 MW Combustion Turbine

Big Rivers Electric Corporation

Unit:	LM1600 CT [1]	
Size:	15	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	7.58	($/kW-Yr.)
VO&M:	3.04	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	10,612	(Btu/kWh)
Installed Cost:	449	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	38.88	($/kW)
Inflation	3.5%	
MMBtu/Day @ 30% CF	1,146	
Amortization Period	20	Years

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	38.88	30.63	7.85	3.15	0.00	46.73	33.78
3.11	2000	38.88	32.99	8.12	3.26	0.00	47.00	36.25
3.14	2001	38.88	33.28	8.41	3.37	0.00	47.29	36.65
3.20	2002	38.88	33.96	8.70	3.49	0.00	47.58	37.45
3.28	2003	38.88	34.83	9.01	3.61	0.00	47.88	38.45
3.36	2004	38.88	35.63	9.32	3.74	0.00	48.20	39.37
3.44	2005	38.88	36.53	9.65	3.87	0.00	48.53	40.40
3.53	2006	38.88	37.43	9.99	4.01	0.00	48.86	41.43
3.60	2007	38.88	38.25	10.34	4.15	0.00	49.21	42.40
3.64	2008	38.88	38.64	10.70	4.29	0.00	49.58	42.93
3.67	2009	38.88	38.93	11.07	4.44	0.00	49.95	43.37
3.69	2010	38.88	39.11	11.46	4.60	0.00	50.34	43.70
3.72	2011	38.88	39.49	11.86	4.76	0.00	50.74	44.25
3.75	2012	38.88	39.76	12.28	4.92	0.00	51.15	44.69
3.74	2013	38.88	39.74	12.71	5.10	0.00	51.58	44.83
3.76	2014	38.88	39.88	13.15	5.28	0.00	52.03	45.16
3.79	2015	38.88	40.25	13.61	5.46	0.00	52.49	45.71
3.83	2016	38.88	40.63	14.09	5.65	0.00	52.96	46.28
3.86	2017	38.88	40.99	14.58	5.85	0.00	53.46	46.84
3.88	2018	38.88	41.13	15.09	6.05	0.00	53.97	47.19
	Average Annual Escalation:		1.56%	3.50%	3.50%	#DIV/0!	0.76%	1.78%
						NPV	565.10	467.93
						20 Yr. Levelized Cost	49.27	40.80

[1] *All costs based on the GE-LM1600 combustion turbine.* Installed cost of $449/kW including IDC.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

LM2500+

LM 2500+ 28 MW Combustion Turbine

Big Rivers Electric Corporation

Unit:	LM2500+ [1]	
Size:	28	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	7.58	($/kW-Yr.)
VO&M:	3.04	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	9,250	(Btu/kWh)
Installed Cost:	594	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	51.37	($/kW)
Inflation	3.5%	
Amortization Period	20	Years

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	51.37	26.70	7.85	3.15	0.00	59.22	29.85
3.11	2000	51.37	28.76	8.12	3.26	0.00	59.49	32.02
3.14	2001	51.37	29.01	8.41	3.37	0.00	59.78	32.38
3.20	2002	51.37	29.60	8.70	3.49	0.00	60.07	33.09
3.28	2003	51.37	30.36	9.01	3.61	0.00	60.38	33.98
3.36	2004	51.37	31.06	9.32	3.74	0.00	60.69	34.80
3.44	2005	51.37	31.84	9.65	3.87	0.00	61.02	35.71
3.53	2006	51.37	32.62	9.99	4.01	0.00	61.36	36.63
3.60	2007	51.37	33.34	10.34	4.15	0.00	61.71	37.49
3.64	2008	51.37	33.68	10.70	4.29	0.00	62.07	37.97
3.67	2009	51.37	33.93	11.07	4.44	0.00	62.44	38.37
3.69	2010	51.37	34.09	11.46	4.60	0.00	62.83	38.69
3.72	2011	51.37	34.42	11.86	4.76	0.00	63.23	39.18
3.75	2012	51.37	34.66	12.28	4.92	0.00	63.65	39.58
3.74	2013	51.37	34.64	12.71	5.10	0.00	64.08	39.73
3.76	2014	51.37	34.76	13.15	5.28	0.00	64.52	40.04
3.79	2015	51.37	35.09	13.61	5.46	0.00	64.98	40.55
3.83	2016	51.37	35.41	14.09	5.65	0.00	65.46	41.06
3.86	2017	51.37	35.73	14.58	5.85	0.00	65.95	41.58
3.88	2018	51.37	35.85	15.09	6.05	0.00	66.46	41.91
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.61%	1.80%
						NPV	708.38	414.01
						20 Yr. Levelized Cost	61.76	36.10

[1] All costs based on the GE-LM2500+ combustion turbine. Installed cost of $594/kW including IDC.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

LM6000

LM6000 45 MW Combustion Turbine

Big Rivers Electric Corporation

Unit:	LM6000	
Size:	44.6	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	4.47	($/kW-Yr.)
VO&M:	2.28	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	9,700	(Btu/kWh)
Installed Cost:	477	($/kW)
Discount Rate:	6.0%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	41.28	($/kW)
Inflation	3.5%	
MMBtu/Day @ 30% CF	3,115	
Amortization Period	20	Years

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	41.28	28.00	4.63	2.36	0.00	45.91	30.36
3.11	2000	41.28	30.16	4.79	2.44	0.00	46.07	32.60
3.14	2001	41.28	30.42	4.96	2.53	0.00	46.24	32.95
3.20	2002	41.28	31.04	5.13	2.62	0.00	46.41	33.66
3.28	2003	41.28	31.84	5.31	2.71	0.00	46.59	34.55
3.36	2004	41.28	32.57	5.49	2.80	0.00	46.77	35.38
3.44	2005	41.28	33.39	5.69	2.90	0.00	46.97	36.29
3.53	2006	41.28	34.21	5.89	3.00	0.00	47.17	37.21
3.60	2007	41.28	34.96	6.09	3.11	0.00	47.37	38.07
3.64	2008	41.28	35.32	6.31	3.22	0.00	47.58	38.53
3.67	2009	41.28	35.58	6.53	3.33	0.00	47.81	38.91
3.69	2010	41.28	35.75	6.75	3.45	0.00	48.03	39.19
3.72	2011	41.28	36.09	6.99	3.57	0.00	48.27	39.66
3.75	2012	41.28	36.34	7.24	3.69	0.00	48.51	40.04
3.74	2013	41.28	36.32	7.49	3.82	0.00	48.77	40.14
3.76	2014	41.28	36.46	7.75	3.95	0.00	49.03	40.41
3.79	2015	41.28	36.80	8.02	4.09	0.00	49.30	40.89
3.83	2016	41.28	37.13	8.30	4.24	0.00	49.58	41.37
3.86	2017	41.28	37.47	8.59	4.38	0.00	49.87	41.86
3.88	2018	41.28	37.60	8.89	4.54	0.00	50.17	42.13
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.47%	1.74%
						NPV	543.71	419.84
						20 Yr. Levelized Cost	47.40	36.60

[1] All costs based on the GE LM6000 aircraft derivative combustion turbine. Installed cost of $477/kW

[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.

[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%

[4] O&M escalated at inflation.

[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.

[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.

[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.

[8] NPV equals net present value. Uses a discount rate shown at left.

251B12

46.3 MW Combustion Turbine [1]

Big Rivers Electric Corporation

Unit:	251B12 [1]	
Size:	46.3	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	4.59	($/kW-Yr.)
VO&M:	2.52	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	12,117	(Btu/kWh)
Installed Cost:	599	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	51.84	($/kW)
Inflation	3.5%	
Gas Escalation	4.2%	
Amotization Period	20	Years

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	51.84	34.97	4.59	2.52	0.00	56.43	37.49
3.11	2000	51.84	37.67	4.75	2.61	0.00	56.59	40.28
3.14	2001	51.84	38.00	4.92	2.70	0.00	56.76	40.70
3.20	2002	51.84	38.78	5.09	2.80	0.00	56.93	41.57
3.28	2003	51.84	39.77	5.27	2.89	0.00	57.11	42.67
3.36	2004	51.84	40.69	5.46	3.00	0.00	57.29	43.68
3.44	2005	51.84	41.71	5.65	3.10	0.00	57.48	44.81
3.53	2006	51.84	42.74	5.84	3.21	0.00	57.68	45.94
3.60	2007	51.84	43.67	6.05	3.32	0.00	57.89	46.99
3.64	2008	51.84	44.12	6.26	3.44	0.00	58.10	47.56
3.67	2009	51.84	44.45	6.48	3.56	0.00	58.32	48.00
3.69	2010	51.84	44.65	6.71	3.68	0.00	58.54	48.34
3.72	2011	51.84	45.09	6.94	3.81	0.00	58.78	48.90
3.75	2012	51.84	45.40	7.18	3.94	0.00	59.02	49.35
3.74	2013	51.84	45.37	7.43	4.08	0.00	59.27	49.46
3.76	2014	51.84	45.54	7.69	4.23	0.00	59.53	49.77
3.79	2015	51.84	45.96	7.96	4.37	0.00	59.80	50.34
3.83	2016	51.84	46.39	8.24	4.53	0.00	60.08	50.91
3.86	2017	51.84	46.81	8.53	4.69	0.00	60.37	51.49
3.88	2018	51.84	46.97	8.83	4.85	0.00	60.67	51.81
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.38%	1.72%
						NPV [8]	664.32	518.00
						20 Yr. Levelized Cost	57.92	45.16

[1] All costs based on the 251B12 simple cycle combustion turbine. Installed cost of $599/kW including IDC.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Combined Cycle

53 MW Combined Cycle
Big Rivers Electric Corporation

Unit:	Combined Cycle [1]	
Size:	53	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	13.98	($/kW-Yr.)
VO&M:	2.10	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost:	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	7,334	(Btu/kWh)
Installed Cost:	608	($/kW)
Discount Rate:	6.0%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	52.61	($/kW)
Inflation	3.5%	
MMBtu/Day @ 30% CF	2,799	
Amortization Period	20	Years

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	52.61	21.17	13.98	2.10	0.00	66.59	23.27
3.11	2000	52.61	22.80	14.47	2.17	0.00	67.08	24.98
3.14	2001	52.61	23.00	14.98	2.25	0.00	67.58	25.25
3.20	2002	52.61	23.47	15.50	2.33	0.00	68.11	25.80
3.28	2003	52.61	24.07	16.04	2.41	0.00	68.65	26.48
3.36	2004	52.61	24.63	16.60	2.49	0.00	69.21	27.12
3.44	2005	52.61	25.25	17.18	2.58	0.00	69.79	27.83
3.53	2006	52.61	25.87	17.79	2.67	0.00	70.39	28.54
3.60	2007	52.61	26.43	18.41	2.76	0.00	71.02	29.20
3.64	2008	52.61	26.70	19.05	2.86	0.00	71.66	29.56
3.67	2009	52.61	26.90	19.72	2.96	0.00	72.33	29.86
3.69	2010	52.61	27.03	20.41	3.07	0.00	73.02	30.09
3.72	2011	52.61	27.29	21.12	3.17	0.00	73.73	30.46
3.75	2012	52.61	27.48	21.86	3.28	0.00	74.47	30.76
3.74	2013	52.61	27.46	22.63	3.40	0.00	75.24	30.86
3.76	2014	52.61	27.56	23.42	3.52	0.00	76.03	31.08
3.79	2015	52.61	27.82	24.24	3.64	0.00	76.85	31.46
3.83	2016	52.61	28.08	25.09	3.77	0.00	77.70	31.84
3.86	2017	52.61	28.33	25.97	3.90	0.00	78.57	32.23
3.88	2018	52.61	28.43	26.88	4.04	0.00	79.48	32.46
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.94%	1.77%
						NPV	815.65	322.23
						20 Yr. Levelized Cost	71.11	28.09

[1] All costs based on the GE combustion turbine with a heat recovery steam generator. Installed cost of $608/kW.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

7EA

7EA 82 MW Combustion Turbine [1]

Big Rivers Electric Corporation

Unit:	7EA[1]	
Size:	82	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	7.38	($/kW-Yr.)
VO&M:	2.99	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	11,861	(Btu/kWh)
Installed Cost:	331	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	28.62	($/kW)
Inflation	3.5%	
Gas Escalation	4.2%	
Amortizatoin Period	20	Years

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	28.62	34.23	7.38	2.99	0.00	36.00	37.22
3.11	2000	28.62	36.88	7.64	3.09	0.00	36.26	39.97
3.14	2001	28.62	37.19	7.91	3.20	0.00	36.52	40.40
3.20	2002	28.62	37.96	8.18	3.32	0.00	36.80	41.27
3.28	2003	28.62	38.93	8.47	3.43	0.00	37.09	42.36
3.36	2004	28.62	39.83	8.77	3.55	0.00	37.38	43.38
3.44	2005	28.62	40.83	9.07	3.68	0.00	37.69	44.51
3.53	2006	28.62	41.83	9.39	3.80	0.00	38.01	45.64
3.60	2007	28.62	42.75	9.72	3.94	0.00	38.34	46.69
3.64	2008	28.62	43.19	10.06	4.08	0.00	38.68	47.26
3.67	2009	28.62	43.51	10.41	4.22	0.00	39.03	47.73
3.69	2010	28.62	43.71	10.77	4.37	0.00	39.39	48.08
3.72	2011	28.62	44.13	11.15	4.52	0.00	39.77	48.65
3.75	2012	28.62	44.44	11.54	4.68	0.00	40.16	49.12
3.74	2013	28.62	44.42	11.95	4.84	0.00	40.56	49.26
3.76	2014	28.62	44.58	12.36	5.01	0.00	40.98	49.59
3.79	2015	28.62	44.99	12.80	5.18	0.00	41.42	50.18
3.83	2016	28.62	45.41	13.24	5.37	0.00	41.86	50.77
3.86	2017	28.62	45.82	13.71	5.55	0.00	42.33	51.37
3.88	2018	28.62	45.97	14.19	5.75	0.00	42.81	51.72
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.92%	1.75%
						NPV [8]	440.31	514.97
						20 Yr. Levelized Cost	38.39	44.90

[1] All costs based on the 7EA simple cycle combustion turbine. Installed cost of $331/kW including IDC
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

501D5A 114.8 MW Combustion Turbine [1]

Big Rivers Electric Corporation

Unit:	501D5A [1]	
Size:	114.8	(MW)
Unit Life:	30	Years
Base Fuel Cost:	2.89	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	5.46	($/kW-Yr.)
VO&M:	2.29	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	11,250	(Btu/kWh)
Installed Cost:	338	($/kW)
Discount Rate:	6.00%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	29.24	($/kW)
Inflation	3.5%	
Gas Escalation	4.2%	
Amortizatoi Period	20	Years

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
2.89	1999	29.24	32.47	5.46	2.29	0.00	34.70	34.76
3.11	2000	29.24	34.98	5.65	2.37	0.00	34.89	37.35
3.14	2001	29.24	35.28	5.85	2.45	0.00	35.09	37.73
3.20	2002	29.24	36.00	6.05	2.54	0.00	35.30	38.54
3.28	2003	29.24	36.93	6.27	2.63	0.00	35.51	39.55
3.36	2004	29.24	37.78	6.48	2.72	0.00	35.73	40.50
3.44	2005	29.24	38.73	6.71	2.81	0.00	35.95	41.54
3.53	2006	29.24	39.68	6.95	2.91	0.00	36.19	42.59
3.60	2007	29.24	40.55	7.19	3.02	0.00	36.43	43.56
3.64	2008	29.24	40.96	7.44	3.12	0.00	36.68	44.08
3.67	2009	29.24	41.27	7.70	3.23	0.00	36.94	44.50
3.69	2010	29.24	41.46	7.97	3.34	0.00	37.21	44.80
3.72	2011	29.24	41.86	8.25	3.46	0.00	37.49	45.32
3.75	2012	29.24	42.15	8.54	3.58	0.00	37.78	45.73
3.74	2013	29.24	42.13	8.84	3.71	0.00	38.08	45.83
3.76	2014	29.24	42.28	9.15	3.84	0.00	38.39	46.12
3.79	2015	29.24	42.68	9.47	3.97	0.00	38.71	46.65
3.83	2016	29.24	43.07	9.80	4.11	0.00	39.04	47.18
3.86	2017	29.24	43.46	10.14	4.25	0.00	39.38	47.71
3.88	2018	29.24	43.60	10.50	4.40	0.00	39.74	48.01
	Average Annual Escalation:		1.56%	3.50%	3.50%		0.72%	1.71%
						NPV [8]	418.31	480.15
						20 Yr. Levelized Cost	36.47	41.86

[1] All costs based on the 501D5A simple cycle combustion turbine. Installed cost of $338/kW including IDC

[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.

[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.

[4] O&M escalated at inflation.

[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.

[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.

[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.

[8] NPV equals net present value. Uses a discount rate shown at left.

Solid Oxide Fuel Cells

Unit:	Fuel Cells [1]	
Size:	20	(MW)
Unit Life:	30	Years
Base Fuel Cost:	4.25	($/mmBtu)
Site Fuel Adder:	0.00%	
Fuel Btu/Unit	1,022	(Btu/cu. ft.)
FO&M:	5.60	($/kW-Yr.)
VO&M:	8.00	($/MWh)
SO2	0	(lb/mmBtu)
SO2 Allowance Cost	200	($/Ton)
NOx	0.032	(lb/mmBtu)
CO2	120	(lb/mmBtu)
CO2 Tax:	0	($/Ton)
Particulate	0	(lb/mmBtu)
Heat Rate:	6,793	(Btu/kWh)
Installed Cost:	1,366	($/kW)
Discount Rate:	6.0%	
Transmission Cost:	0.00	($/kW-Yr.)
Losses:	0.0%	
Yearly Cost:	118.21	($/kW)
Amortization Period	20	Years
Inflation	3.5%	
Gas Escalation	4.2%	

Solid Oxide Fuel Cells [1]

Big Rivers Electric Corporation

Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
4.25	1999	118.21	28.87	5.60	8.00	0.00	123.81	36.87
4.43	2000	118.21	30.08	5.80	8.28	0.00	124.01	38.36
4.61	2001	118.21	31.34	6.00	8.57	0.00	124.21	39.91
4.81	2002	118.21	32.65	6.21	8.87	0.00	124.42	41.52
5.01	2003	118.21	34.01	6.43	9.18	0.00	124.64	43.19
5.22	2004	118.21	35.44	6.65	9.50	0.00	124.86	44.94
5.43	2005	118.21	36.92	6.88	9.83	0.00	125.10	46.75
5.66	2006	118.21	38.46	7.12	10.18	0.00	125.34	48.64
5.90	2007	118.21	40.07	7.37	10.53	0.00	125.59	50.61
6.15	2008	118.21	41.75	7.63	10.90	0.00	125.84	52.65
6.40	2009	118.21	43.49	7.90	11.28	0.00	126.11	54.78
6.67	2010	118.21	45.31	8.18	11.68	0.00	126.39	56.99
6.95	2011	118.21	47.21	8.46	12.09	0.00	126.67	59.30
7.24	2012	118.21	49.18	8.76	12.51	0.00	126.97	61.70
7.54	2013	118.21	51.24	9.06	12.95	0.00	127.28	64.19
7.86	2014	118.21	53.39	9.38	13.40	0.00	127.59	66.79
8.19	2015	118.21	55.62	9.71	13.87	0.00	127.92	69.49
8.53	2016	118.21	57.95	10.05	14.36	0.00	128.26	72.30
8.89	2017	118.21	60.37	10.40	14.86	0.00	128.61	75.23
9.26	2018	118.21	69.69	10.77	15.38	0.00	128.98	85.07
	Average Annual Escalation:		4.75%	3.50%	3.50%		0.22%	4.50%
						NPV [8]	1,440.90	588.11
						20 Yr. Levelized Cost	125.62	51.27

[1] All costs based on the solid oxide fuel cell. Installed cost of $1,366/kW.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Wind Turbines

Wind Turbines [1]

Big Rivers Electric Corporation

Unit:	Wind Turbines [1]		Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
Size:	0.08	(MW)	0.00	1999	147.96	0.00	25.00	0.00	0.00	172.96	0.00
Unit Life:	30	Years	0.00	2000	147.96	0.00	25.88	0.00	0.00	173.83	0.00
Base Fuel Cost:	0.00	($/mmBtu)	0.00	2001	147.96	0.00	26.78	0.00	0.00	174.74	0.00
Site Fuel Adder:	0.00%		0.00	2002	147.96	0.00	27.72	0.00	0.00	175.67	0.00
Fuel Btu/Unit	0	(Btu/cu. ft.)	0.00	2003	147.96	0.00	28.69	0.00	0.00	176.64	0.00
FO&M:	25.00	($/kW-Yr.)	0.00	2004	147.96	0.00	29.69	0.00	0.00	177.65	0.00
VO&M:	0	($/MWh)	0.00	2005	147.96	0.00	30.73	0.00	0.00	178.69	0.00
SO2	0	(lb/mmBtu)	0.00	2006	147.96	0.00	31.81	0.00	0.00	179.76	0.00
SO2 Allowance Cost:	200	($/Ton)	0.00	2007	147.96	0.00	32.92	0.00	0.00	180.88	0.00
NOx	0	(lb/mmBtu)	0.00	2008	147.96	0.00	34.07	0.00	0.00	182.03	0.00
CO2	0	(lb/mmBtu)	0.00	2009	147.96	0.00	35.26	0.00	0.00	183.22	0.00
CO2 Tax:	0	($/Ton)	0.00	2010	147.96	0.00	36.50	0.00	0.00	184.46	0.00
Particulate	0	(lb/mmBtu)	0.00	2011	147.96	0.00	37.78	0.00	0.00	185.73	0.00
Heat Rate:	0	(Btu/kWh)	0.00	2012	147.96	0.00	39.10	0.00	0.00	187.05	0.00
Installed Cost:	1,710	($/kW)	0.00	2013	147.96	0.00	40.47	0.00	0.00	188.42	0.00
Discount Rate:	6.0%		0.00	2014	147.96	0.00	41.88	0.00	0.00	189.84	0.00
Transmission Cost:	0.00	($/kW-Yr.)	0.00	2015	147.96	0.00	43.35	0.00	0.00	191.31	0.00
Losses:	0.0%		0.00	2016	147.96	0.00	44.87	0.00	0.00	192.82	0.00
Yearly Cost:	147.96	($/kW)	0.00	2017	147.96	0.00	46.44	0.00	0.00	194.39	0.00
Inflation	3.5%		0.00	2018	147.96	0.00	48.06	0.00	0.00	196.02	0.00
Amortization Period	20	Years									
				Average Annual Escalation:			0.035			0.007	
									NPV [8]	2,076.62	0.00
									20 Yr. Levelized Cost	181.05	0.00

[1] Installed cost of $1710/kW including IDC based on the 80 kW wind turbine installation costs at Waverly, Iowa.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] N/A
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

Biomass

Biomass [1]

Big Rivers Electric Corporation

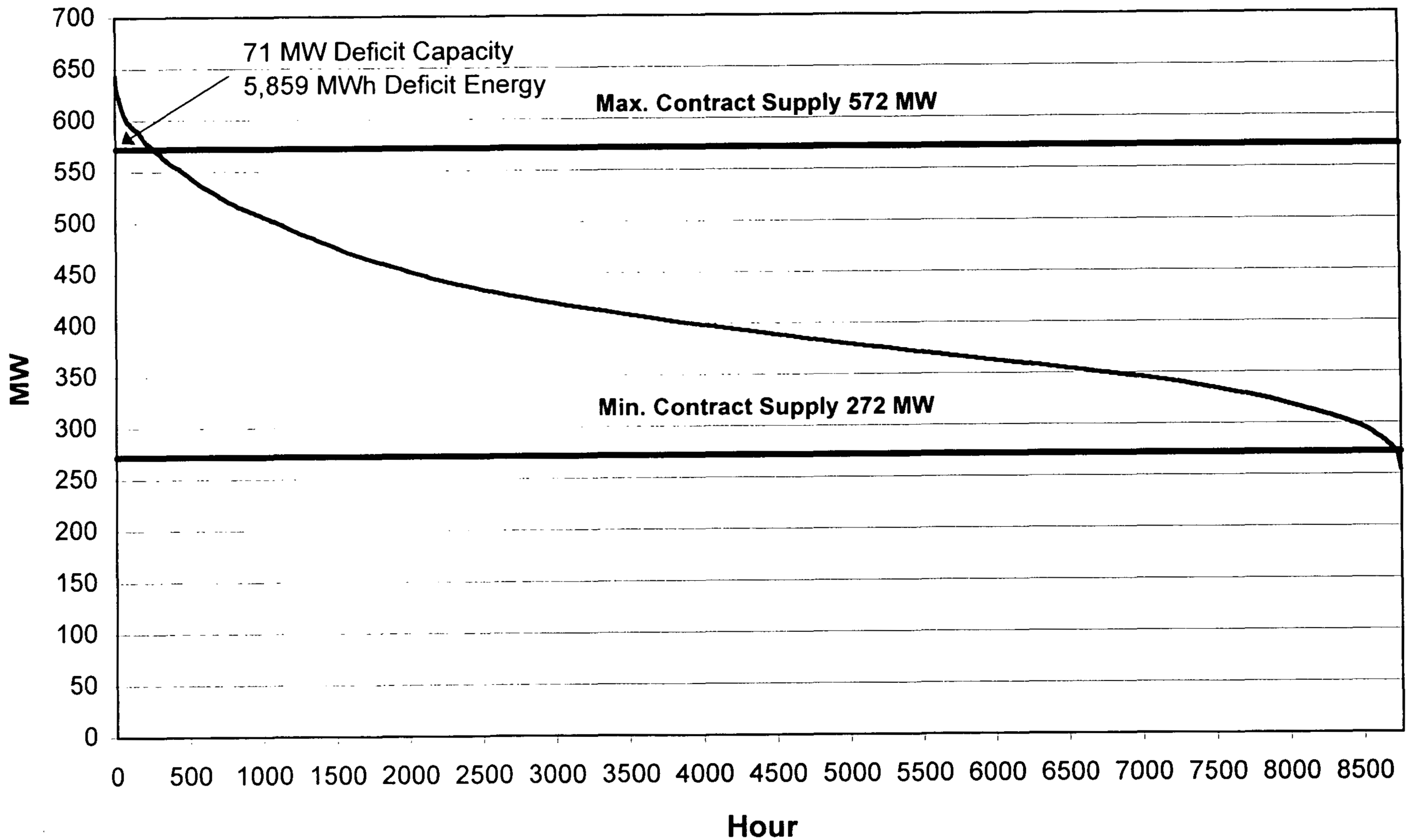
Unit:	Biomass [1]		Delivered Real Fuel Cost ($/mmBtu)	Year	Capital Cost ($/kW-Yr.) [2]	Fuel Cost ($/MWh) [3]	Fixed O&M ($/kW-Yr.) [4]	Variable O&M ($/MWh) [4]	SO_2 Allowances ($/MWh) [5]	Fixed Cost Total ($/kW-Yr.) [6]	Variable Cost Total ($/MWh) [7]
Size:		(MW)	2.48	1999	155.73	34.47	87.70	8.10	0.00	243.43	42.57
Unit Life:	30	Years	2.57	2000	155.73	35.68	90.77	8.38	0.00	246.50	44.06
Base Fuel Cost:	2.48	($/mmBtu)	2.66	2001	155.73	36.93	93.95	8.68	0.00	249.68	45.60
Site Fuel Adder:	0.00%		2.75	2002	155.73	38.22	97.23	8.98	0.00	252.96	47.20
Fuel Btu/Unit	~5550	(Btu/lb)	2.85	2003	155.73	39.56	100.64	9.29	0.00	256.37	48.85
FO&M:	87.70	($/kW-Yr.)	2.95	2004	155.73	40.94	104.16	9.62	0.00	259.89	50.56
VO&M:	8.1	($/MWh)	3.05	2005	155.73	42.38	107.81	9.96	0.00	263.53	52.33
SO2	0	(lb/mmBtu)	3.16	2006	155.73	43.86	111.58	10.31	0.00	267.31	54.16
SO2 Allowance Cost	200	($/Ton)	3.27	2007	155.73	45.39	115.48	10.67	0.00	271.21	56.06
NOx	0	(lb/mmBtu)	3.38	2008	155.73	46.98	119.53	11.04	0.00	275.25	58.02
CO2	0	(lb/mmBtu)	3.50	2009	155.73	48.63	123.71	11.43	0.00	279.44	60.05
CO2 Tax:	0	($/Ton)	3.62	2010	155.73	50.33	128.04	11.83	0.00	283.77	62.15
Particulate	0	(lb/mmBtu)	3.75	2011	155.73	52.09	132.52	12.24	0.00	288.25	64.33
Heat Rate:	13,893	(Btu/kWh)	3.88	2012	155.73	53.91	137.16	12.67	0.00	292.89	66.58
Installed Cost:	1,800	($/kW)	4.02	2013	155.73	55.80	141.96	13.11	0.00	297.69	68.91
Discount Rate:	6.0%		4.16	2014	155.73	57.75	146.93	13.57	0.00	302.66	71.32
Transmission Cost:	0.00	($/kW-Yr.)	4.30	2015	155.73	59.78	152.07	14.05	0.00	307.80	73.82
Losses:	0.0%		4.45	2016	155.73	61.87	157.39	14.54	0.00	313.12	76.40
Yearly Cost:	155.73	($/kW)	4.61	2017	155.73	64.03	162.90	15.05	0.00	318.63	79.08
Inflation	3.5%		4.77	2018	155.73	66.27	168.60	15.57	0.00	324.33	81.85
Amortization Period	20	Years									
				Average Annual Escalation:		3.50%	3.50%	3.50%		1.52%	3.50%
									NPV [8]	3,117.74	646.38
									20 Yr. Levelized Cost	271.82	56.35

[1] Installed cost of $1800/kW including IDC based on a conventional steam-turbine facility.
[2] Annual capital cost calculated based on the amortization period and discount rate shown on the left.
[3] Fuel Cost based on 1998 average natural gas costs for Louisville Gas & Electric. Escalation based on the natural gas price forecast of the Energy Information Administration as included in the 1999 Annual Energy Outlook and an inflation rate of 3.5%.
[4] O&M escalated at inflation.
[5] SO_2 Allowances projected at $200/ton in 1999. Escalated at inflation. Assumes an SO_2 emissions rate of 0 lb/mmBtu.
[6] Fixed Cost Total is the sum of Capital Costs and Fixed O&M.
[7] Variable Cost Total is the sum of Fuel Cost, Variable O&M and SO_2 Allowances.
[8] NPV equals net present value. Uses a discount rate shown at left.

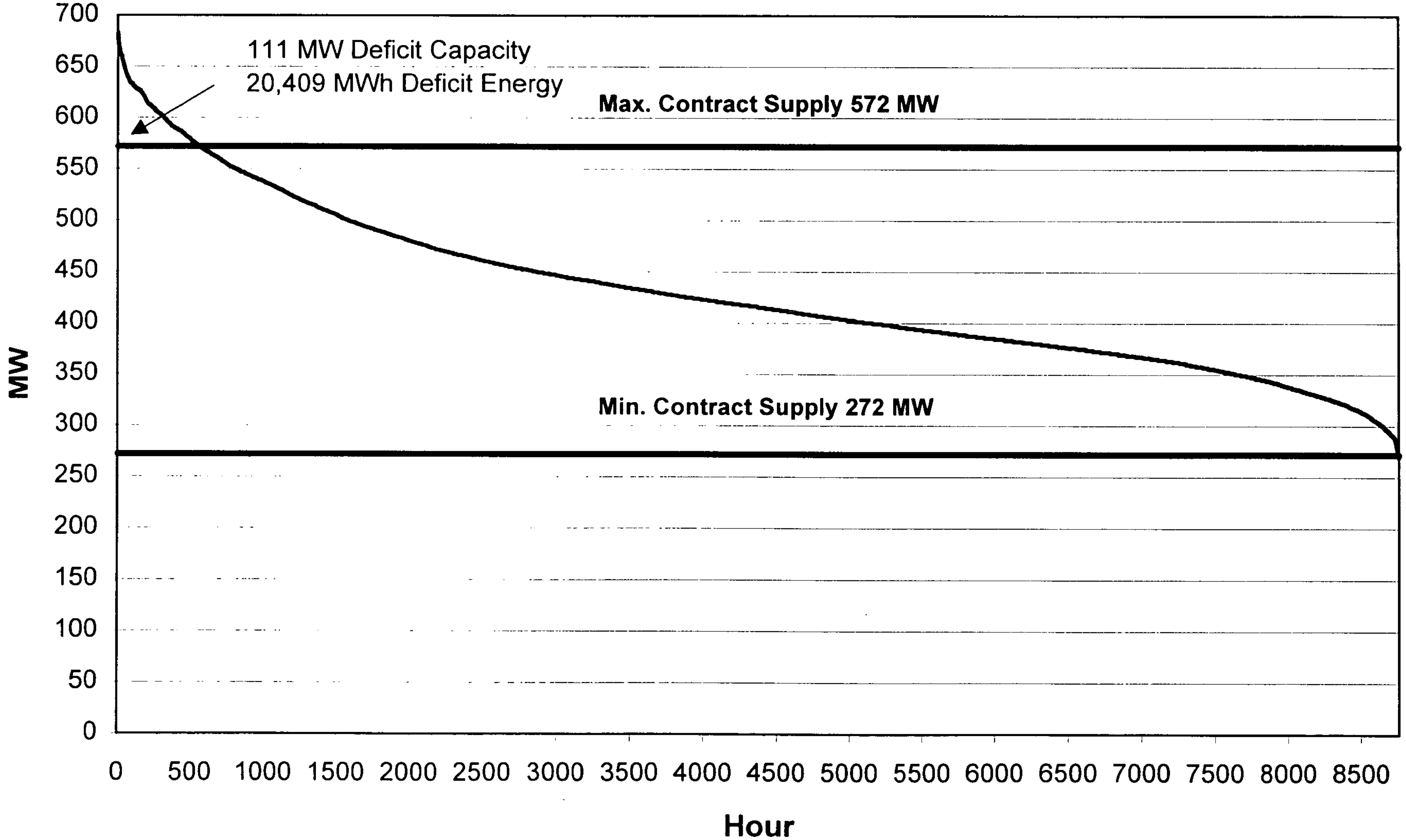
Appendix C

Projected Load Duration Curves

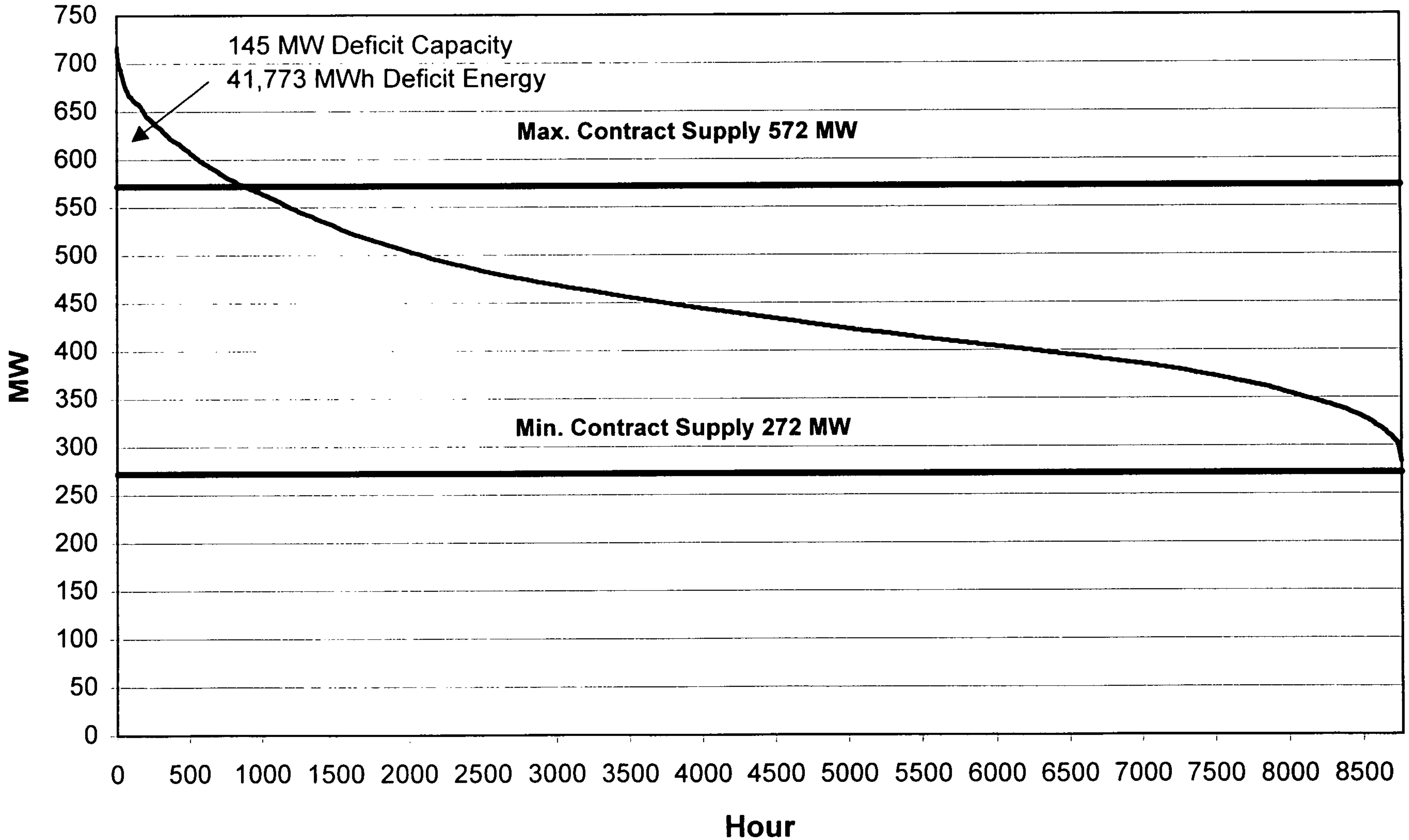
Projected 1998 Load Duration Curve
Big Rivers Electric Corporation



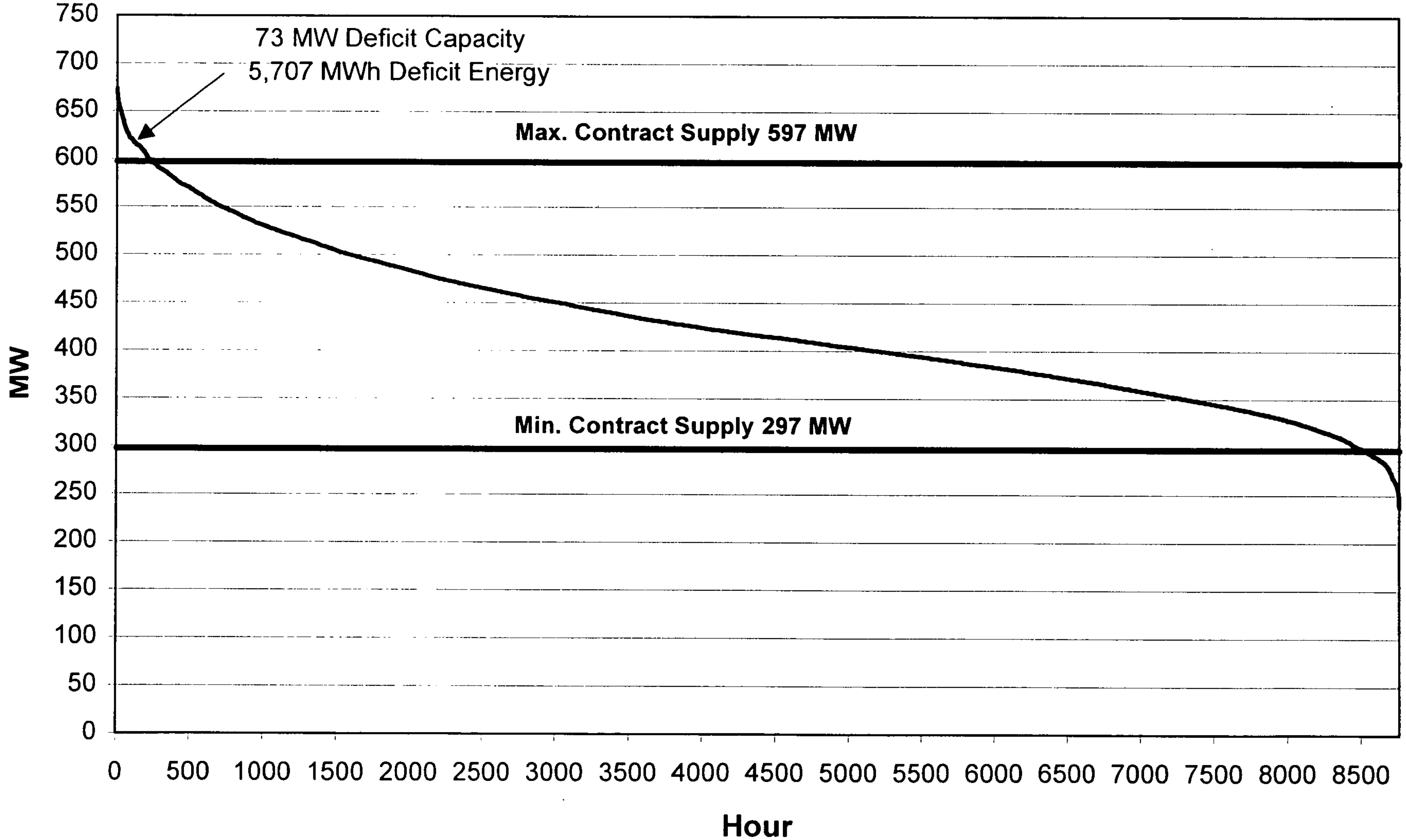
Projected 1999 Load Duration Curve
Big Rivers Electric Corporation



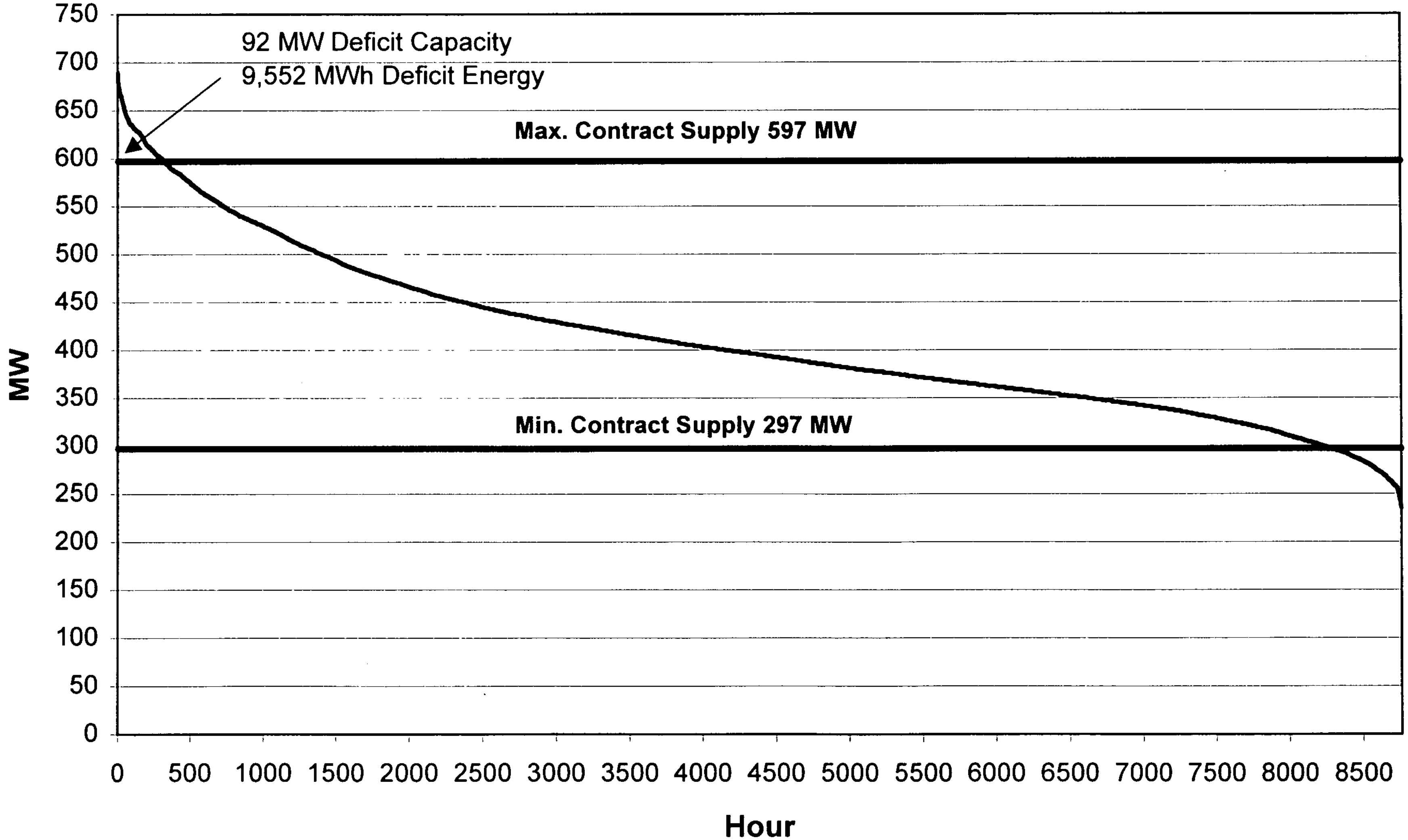
Projected 2000 Load Duration Curve
Big Rivers Electric Corporation



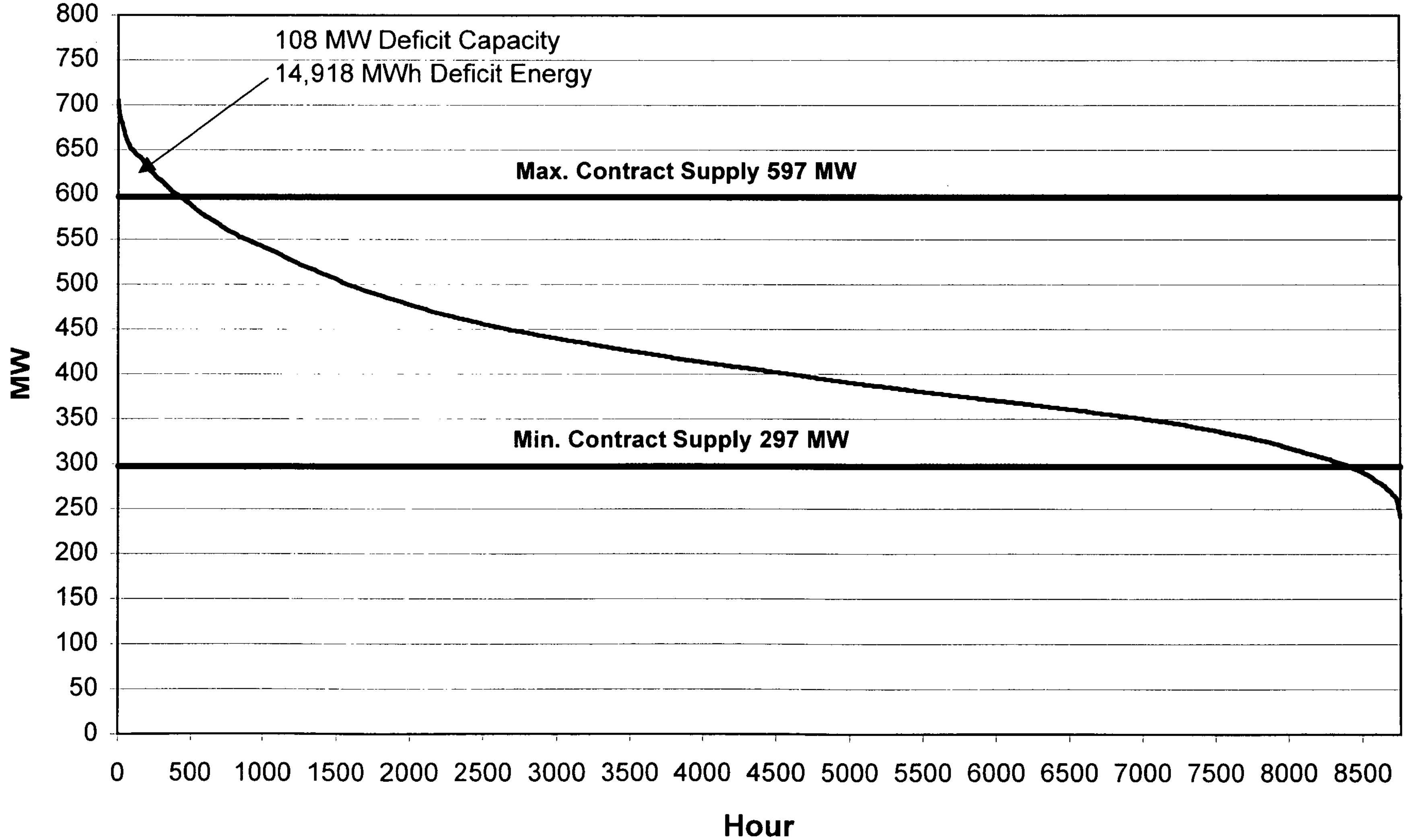
Projected 2001 Load Duration Curve
Big Rivers Electric Corporation

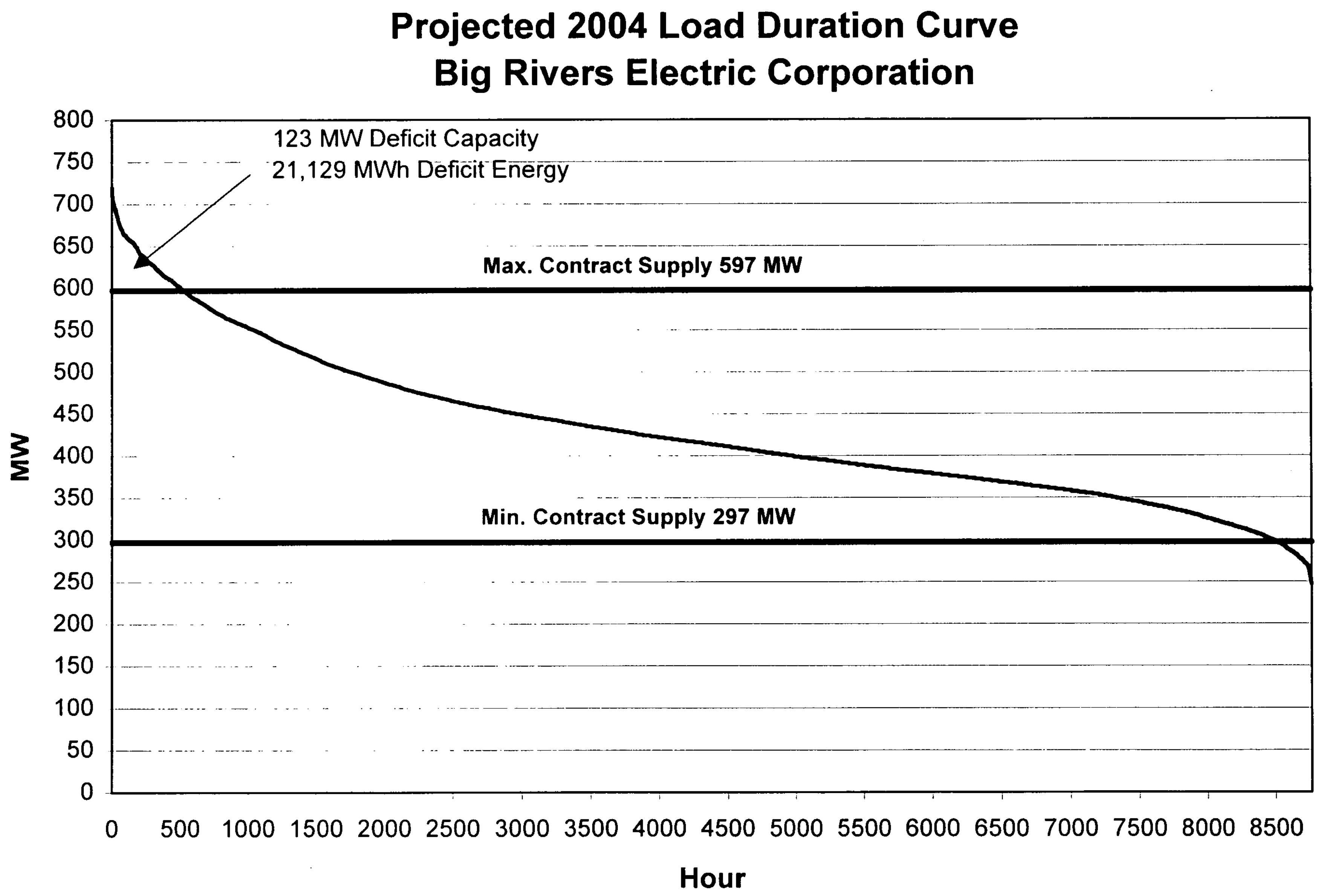


Projected 2002 Load Duration Curve
Big Rivers Electric Corporation



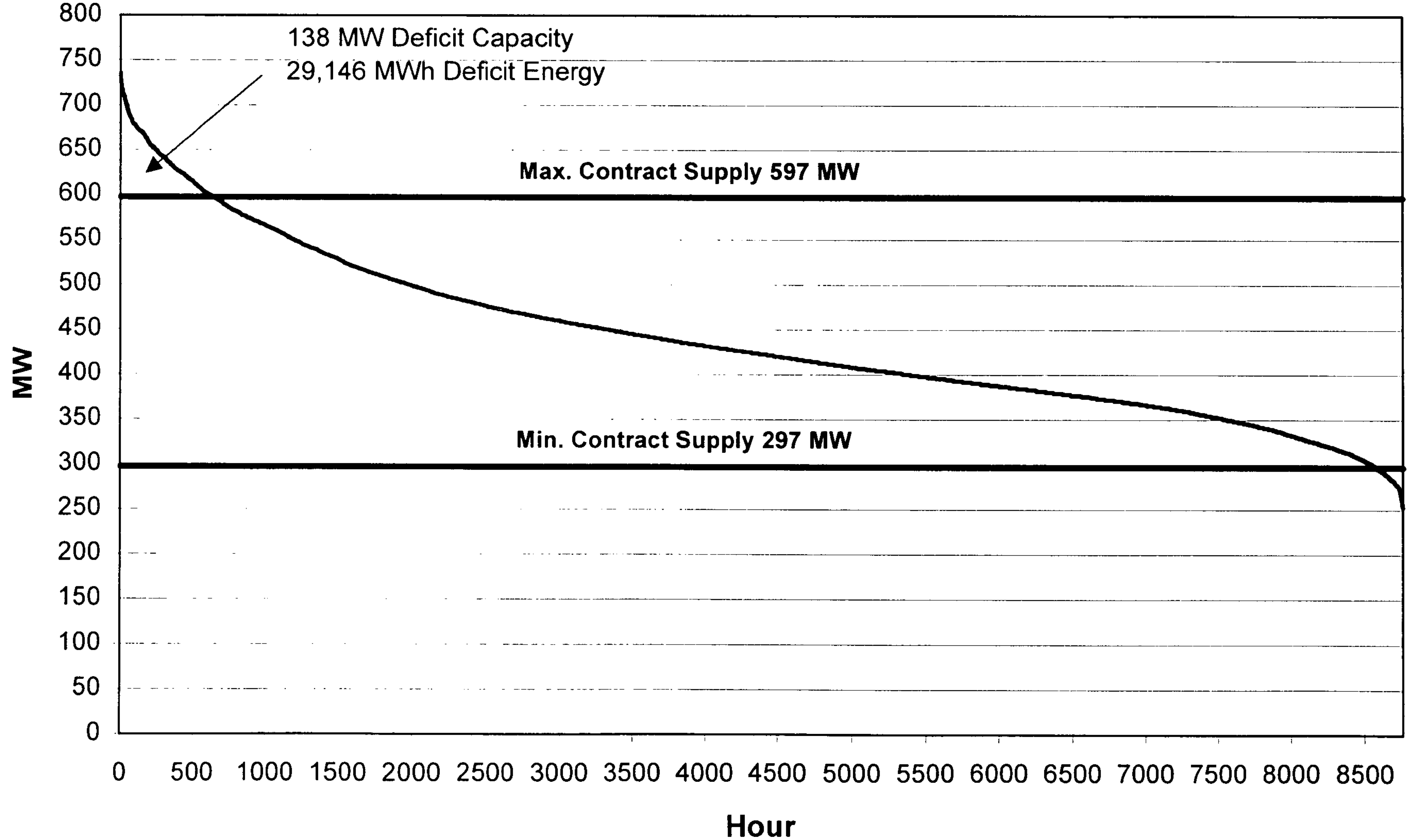
Projected 2003 Load Duration Curve
Big Rivers Electric Corporation



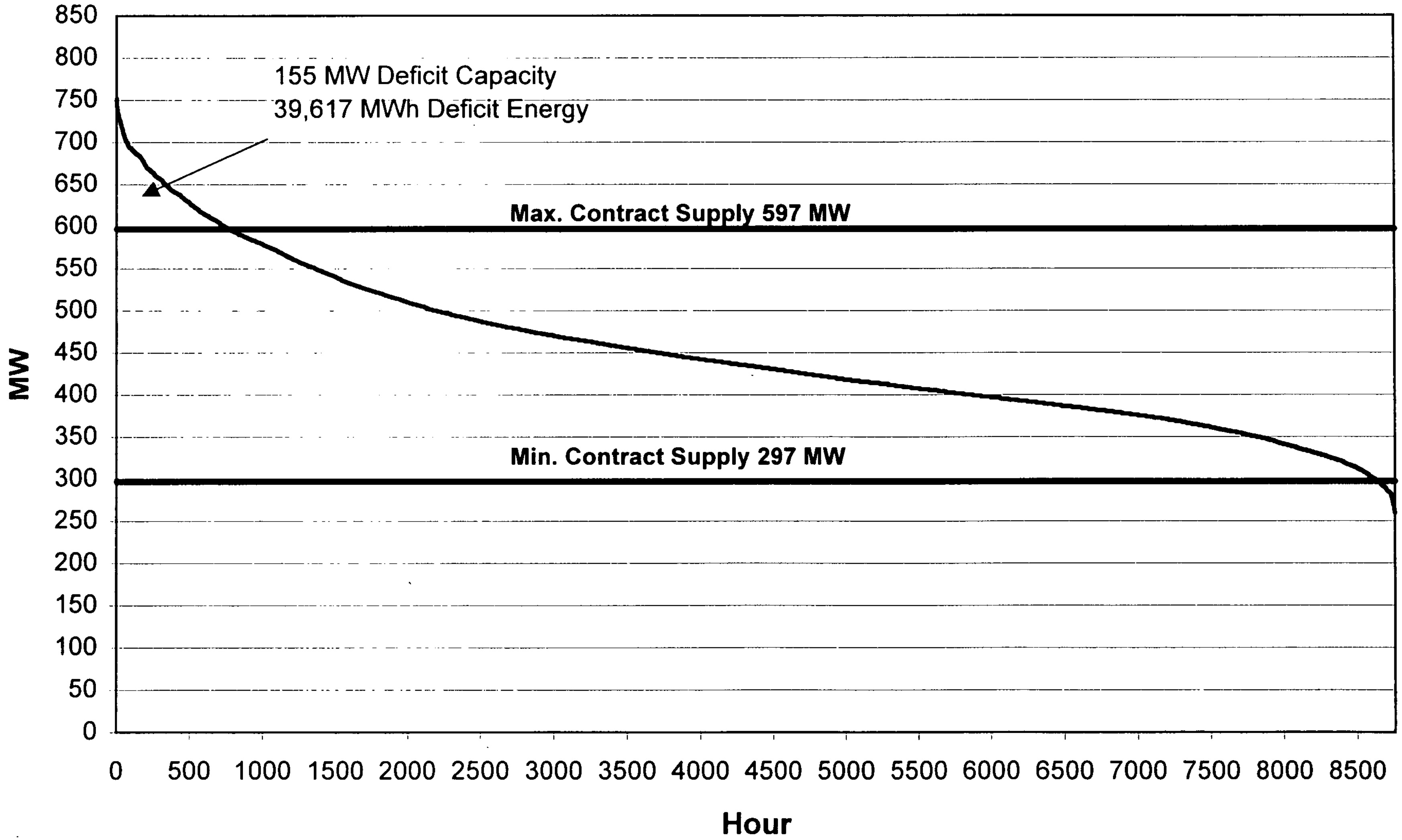


Projected 2004 Load Duration Curve
Big Rivers Electric Corporation
123 MW Deficit Capacity
21,129 MWh Deficit Energy
Max. Contract Supply 597 MW
Min. Contract Supply 297 MW
MW
800
750
700
650
600
550
500
450
400
350
300
250
200
150
100
50
0
0 500 1000 1500 2000 2500 3000 3500 4000 4500 5000 5500 6000 6500 7000 7500 8000 8500
Hour

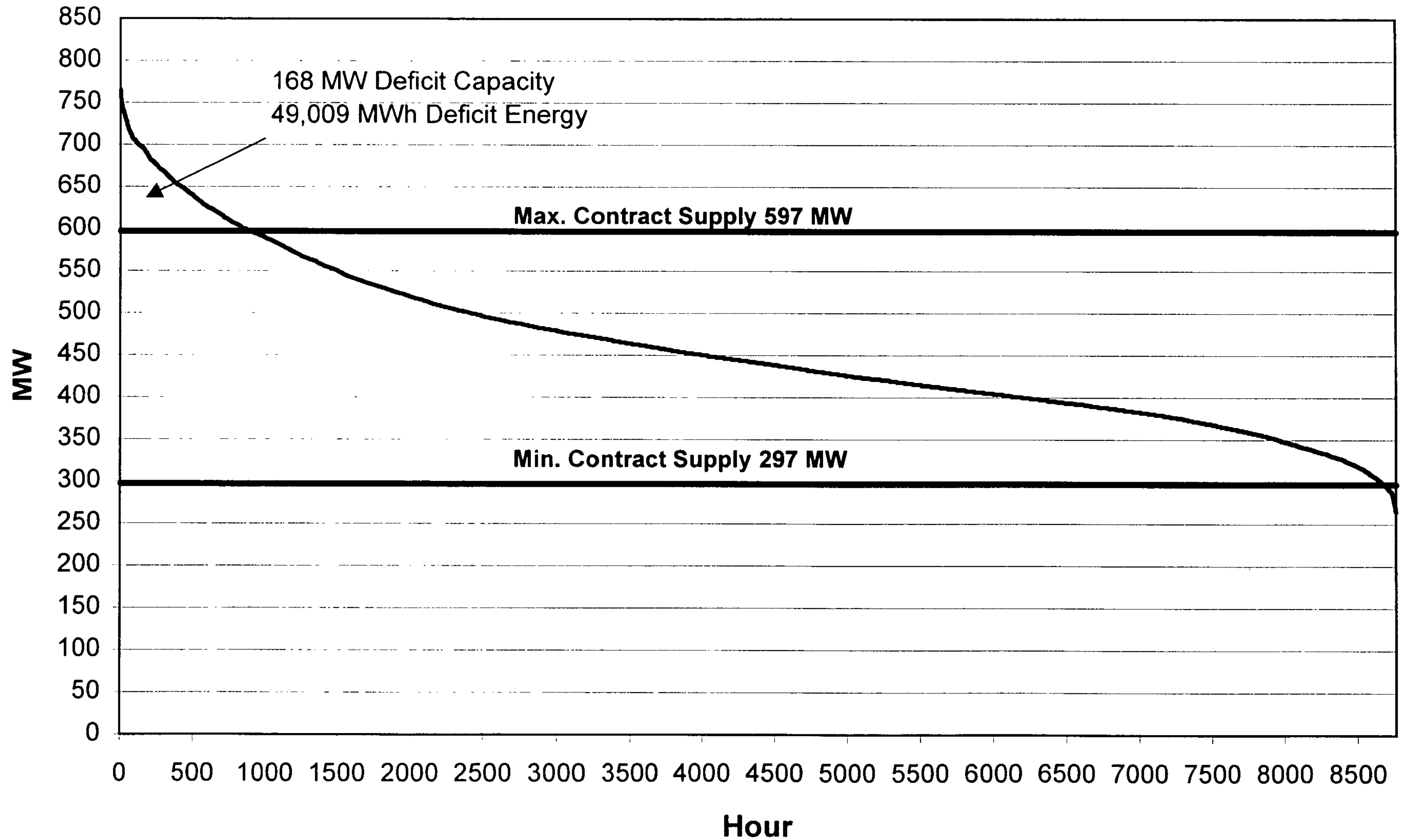
Projected 2005 Load Duration Curve
Big Rivers Electric Corporation



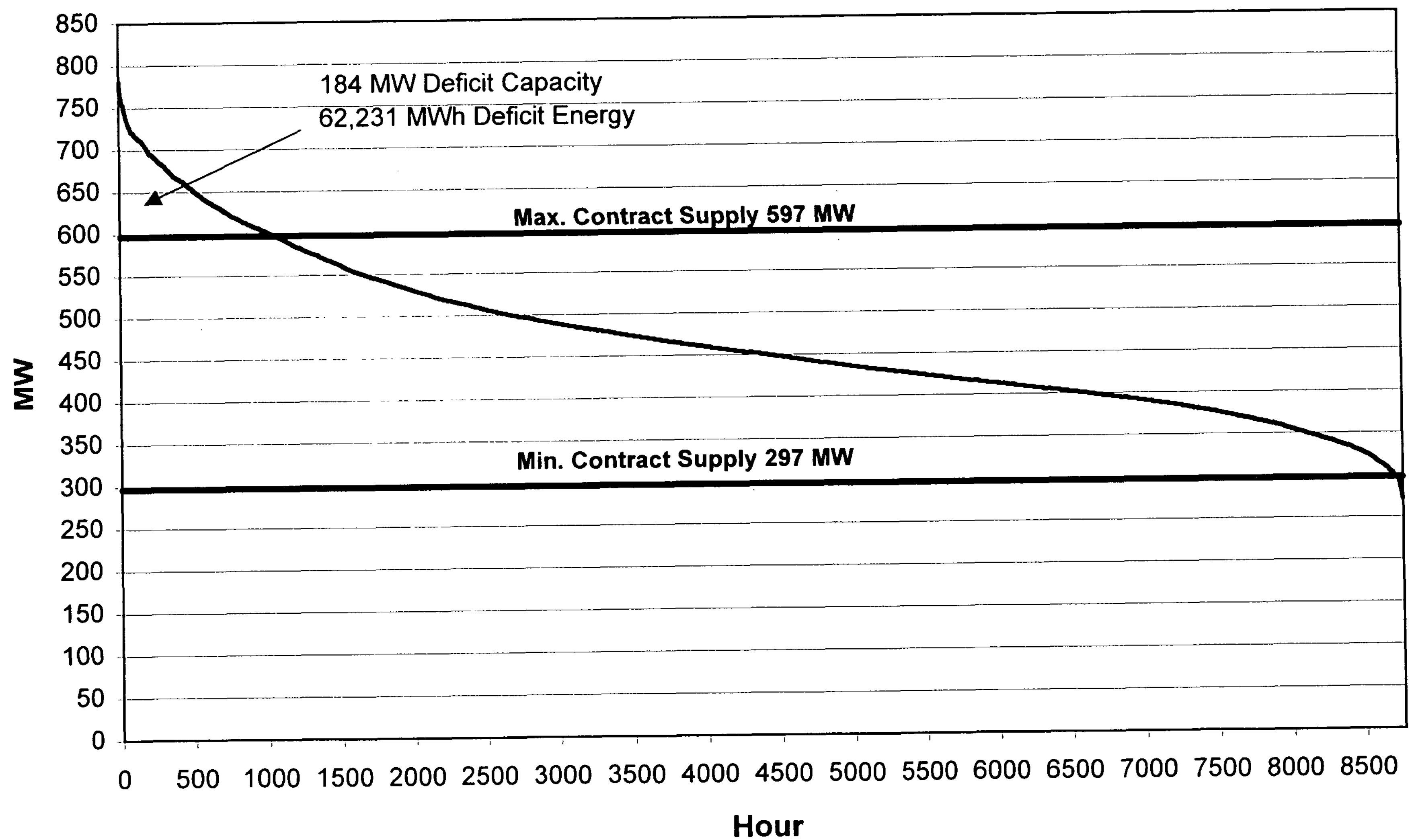
Projected 2006 Load Duration Curve
Big Rivers Electric Corporation



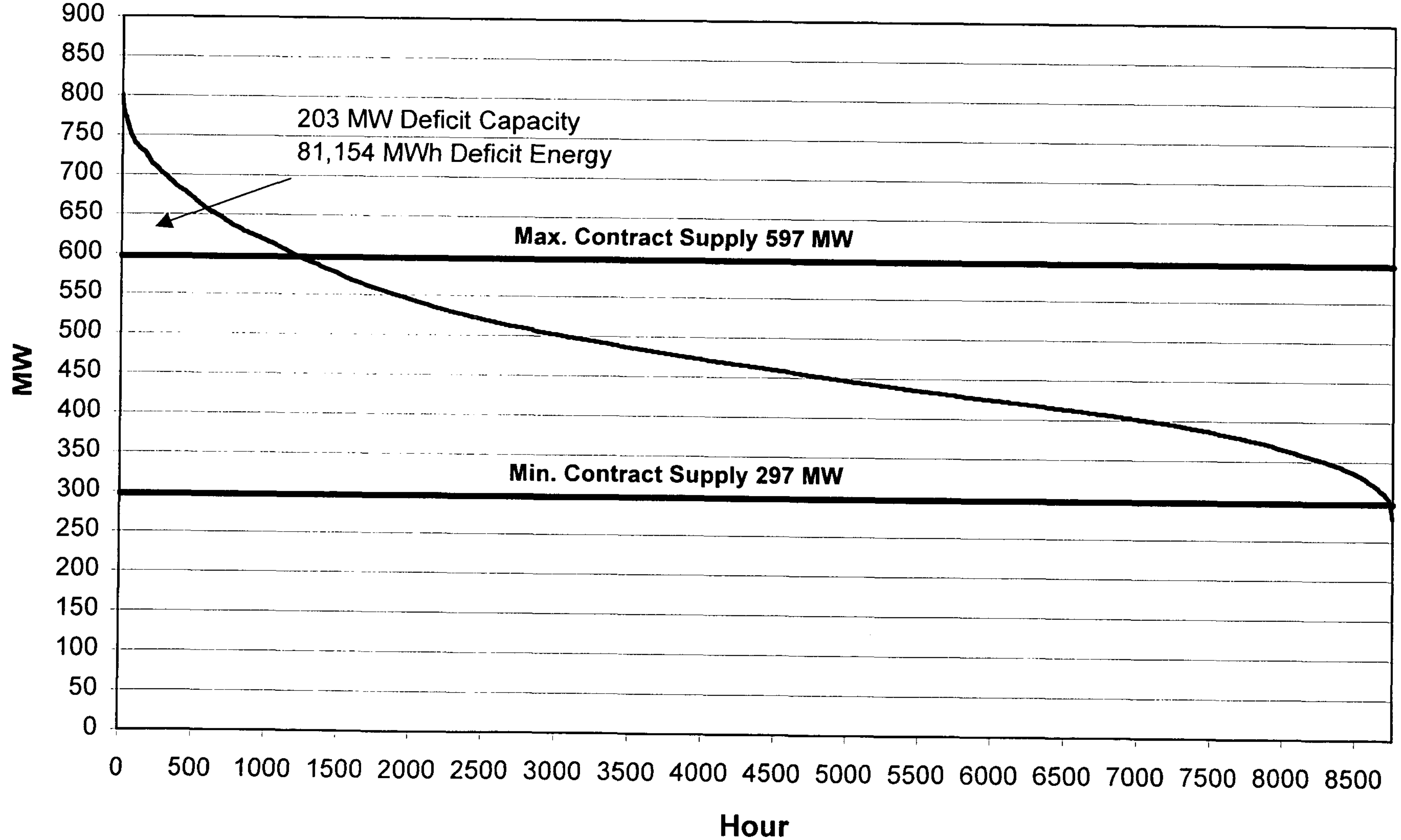
Projected 2007 Load Duration Curve
Big Rivers Electric Corporation



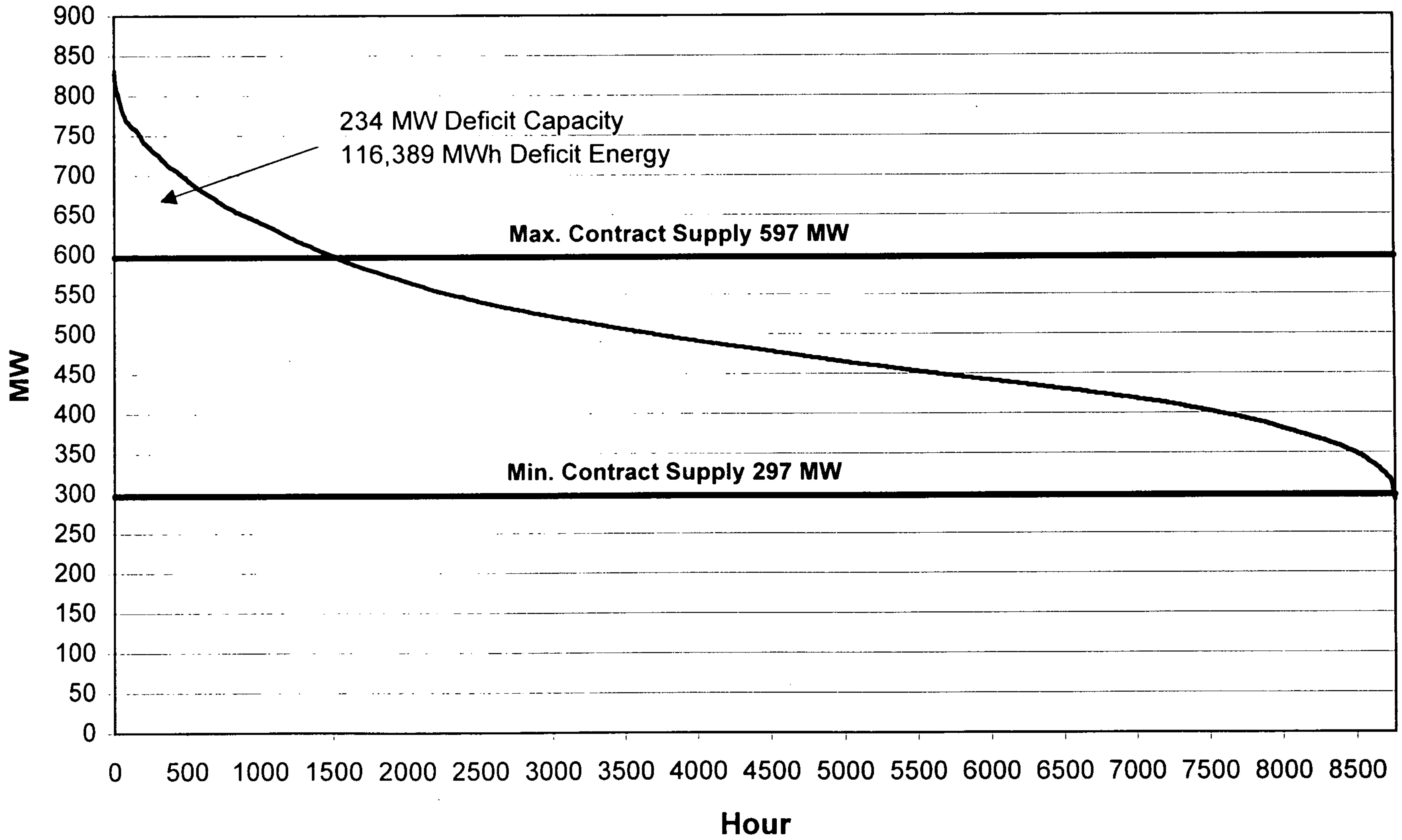
Projected 2008 Load Duration Curve
Big Rivers Electric Corporation



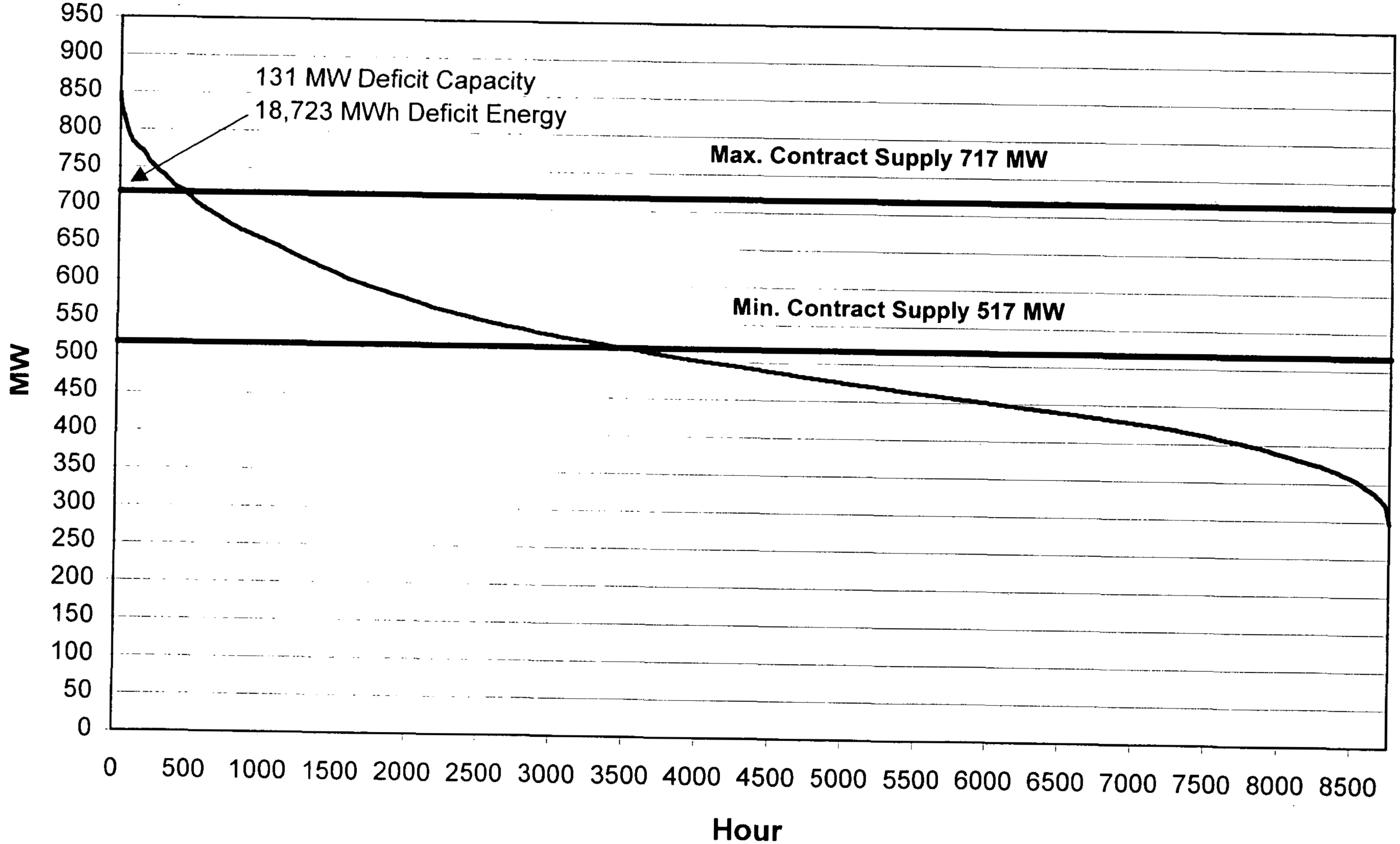
Projected 2009 Load Duration Curve
Big Rivers Electric Corporation

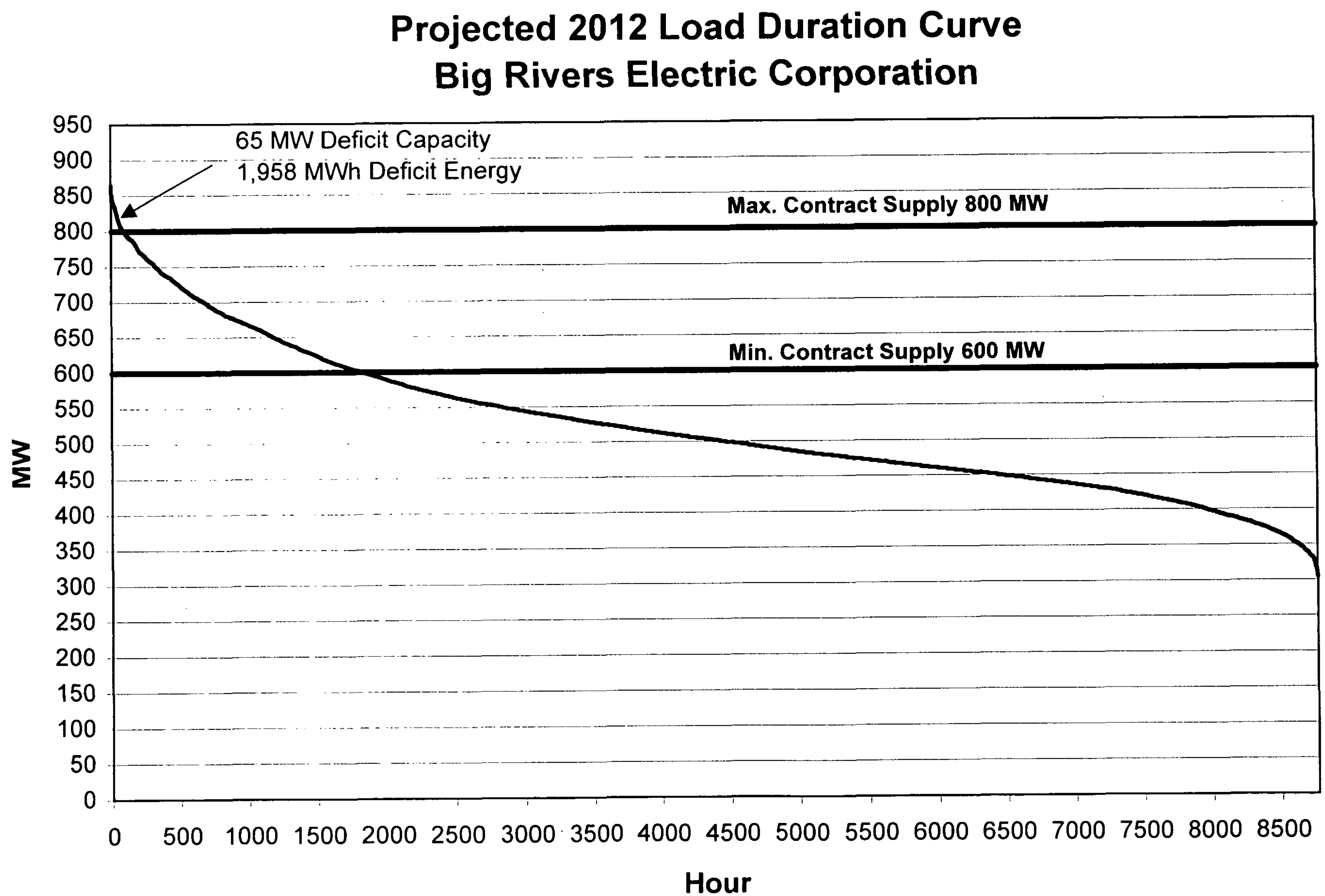


Projected 2010 Load Duration Curve
Big Rivers Electric Corporation



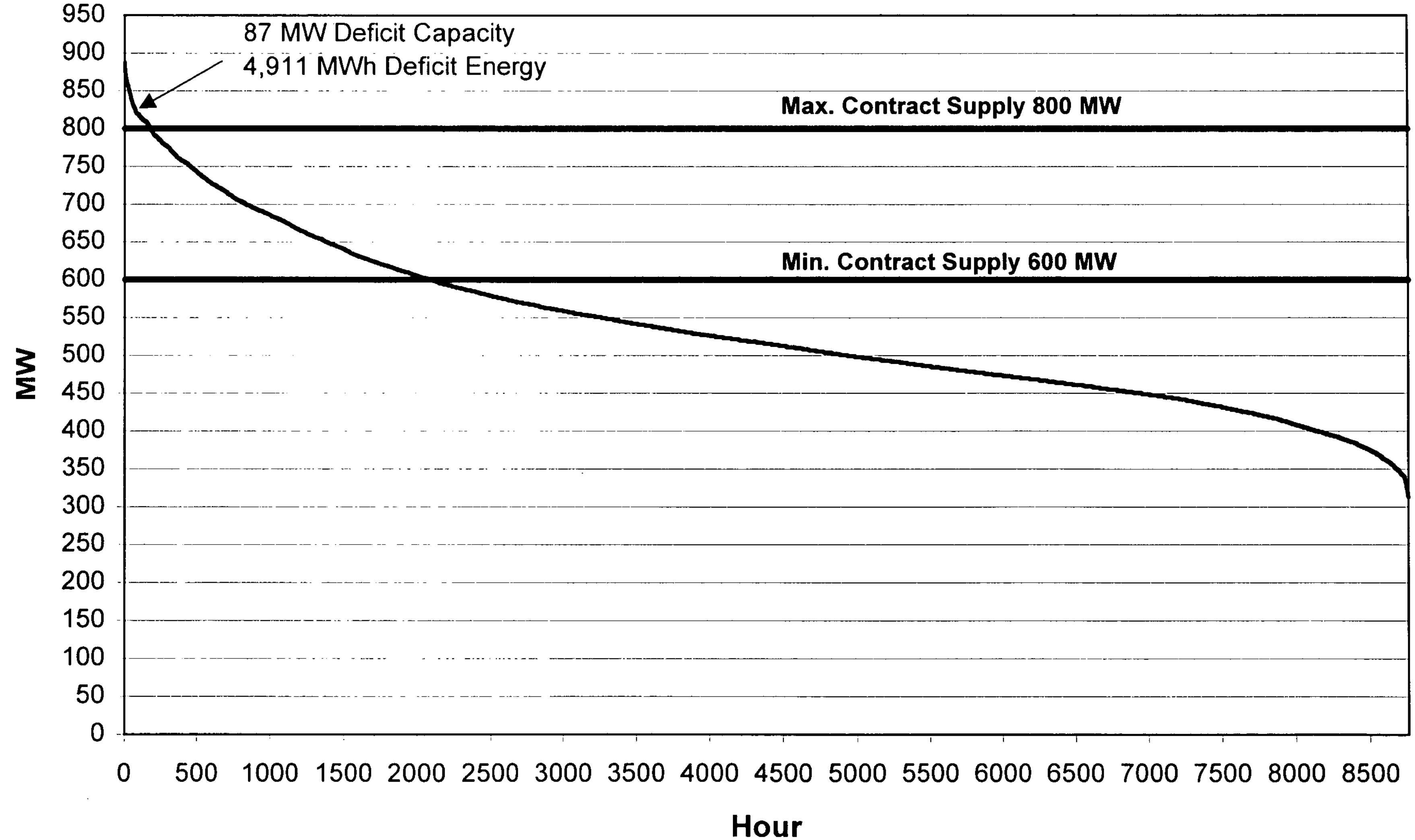
Projected 2011 Load Duration Curve
Big Rivers Electric Corporation





Projected 2012 Load Duration Curve
Big Rivers Electric Corporation
65 MW Deficit Capacity
1,958 MWh Deficit Energy
Max. Contract Supply 800 MW
Min. Contract Supply 600 MW
MW
950
900
850
800
750
700
650
600
550
500
450
400
350
300
250
200
150
100
50
0
0
500
1000
1500
2000
2500
3000
3500
4000
4500
5000
5500
6000
6500
7000
7500
8000
8500
Hour

Projected 2013 Load Duration Curve
Big Rivers Electric Corporation



Appendix D

Production Cost Modeling

Case 0:

Unmet requirements purchased from spot market - no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours
1999	683	0	3,764,310	267,000	3,497,310	0	0
2000	717	0	3,952,672	267,000	3,685,672	0	0
2001	673	0	3,736,992	267,000	3,469,993	0	0
2002	689	0	3,599,696	267,000	3,332,696	0	0
2003	705	0	3,687,188	267,000	3,420,187	0	0
2004	720	0	3,766,563	267,000	3,499,563	0	0
2005	735	0	3,852,240	267,000	3,585,240	0	0
2006	752	0	3,945,241	267,000	3,678,241	0	0
2007	765	0	4,017,067	267,000	3,750,067	0	0
2008	781	6	4,104,079	267,000	3,837,073	6	2
2009	800	25	4,212,008	267,000	3,944,843	164	18
2010	831	56	4,382,024	267,000	4,113,345	1,679	72
2011	848	0	4,472,576	267,000	4,205,576	0	0
2012	865	0	4,566,520	267,000	4,299,521	0	0
2013	887	0	4,692,492	267,000	4,425,492	0	0

Year	Variable Costs/(Revenues)			Fixed Costs/(Revenues)			Total Annual Costs
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of Spot Market Energy Purchases	LEM	SEPA	Capacity Deficits/ (Surplus)	
1999		$0	$0		$6,088,000	$0	
2000		$0	$0		$6,194,000	$0	
2001		$0	$0		$6,194,000	$0	
2002		$0	$0		$6,194,000	$0	
2003		$0	$0		$6,194,000	$0	
2004		$0	$0		$6,264,000	$0	
2005		$0	$0		$6,403,000	$0	
2006		$0	$0		$6,548,000	$0	
2007		$0	$0		$6,695,000	$0	
2008		$0	$720		$6,846,000	$388,800	
2009		$0	$22,192		$7,000,000	$1,650,000	
2010		$0	$166,056		$7,157,000	$3,763,200	
2011		$0	$0		$7,318,000	$0	
2012		$0	$0		$7,483,000	$0	
2013		$0	$0		$7,651,000	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

Case 1:
Installation of 45 MW CT in 2002 - no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Generation from 45 MW CT (MWh)	Energy Requirement Unmet by 45 MW CT (MWh)
1999	683	0	3,764,310	267,000	3,497,310	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	0	0	0	0
2008	781	6	4,104,079	267,000	3,837,073	6	2	6	0
2009	800	25	4,212,008	267,000	3,944,843	164	18	164	0
2010	831	56	4,382,024	267,000	4,113,345	1,679	72	1,574	105
2011	848	0	4,472,576	267,000	4,205,576	0	0	0	0
2012	865	0	4,566,520	267,000	4,299,521	0	0	0	0
2013	887	0	4,692,492	267,000	4,425,492	0	0	0	0

Year	Variable Costs/(Revenues)				Fixed Costs/(Revenues)				Total Annual Costs
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 45 MW CT Generation to Meet Requirements	Cost of Spot Market Energy Purchases	LEM	SEPA	45 MW CT	Capacity Deficits/ (Surplus)	
1999		$0	$0	$0		$6,088,000	$0	$0	
2000		$0	$0	$0		$6,194,000	$0	$0	
2001		$0	$0	$0		$6,194,000	$0	$0	
2002		$0	$0	$0		$6,194,000	$2,069,886	$0	
2003		$0	$0	$0		$6,194,000	$2,077,914	$0	
2004		$0	$0	$0		$6,264,000	$2,085,942	$0	
2005		$0	$0	$0		$6,403,000	$2,094,862	$0	
2006		$0	$0	$0		$6,548,000	$2,103,782	$0	
2007		$0	$0	$0		$6,695,000	$2,112,702	$0	
2008		$0	$227	$0		$6,846,000	$2,122,068	$0	
2009		$0	$6,058	$0		$7,000,000	$2,132,326	$0	
2010		$0	$58,395	$7,269		$7,157,000	$2,142,138	$739,200	
2011		$0	$0	$0		$7,318,000	$2,152,842	$0	
2012		$0	$0	$0		$7,483,000	$2,163,546	$0	
2013		$0	$0	$0		$7,651,000	$2,175,142	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

Case 1:
Installation of 45 MW CT in 2009 - no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Generation from 45 MW CT (MWh)	Energy Requirement Unmet by 45 MW CT (MWh)
1999	683	0	3,764,310	267,000	3,497,310	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	0	0	0	0
2008	781	6	4,104,079	267,000	3,837,073	6	2	0	6
2009	800	25	4,212,008	267,000	3,944,843	164	18	164	0
2010	831	56	4,382,024	267,000	4,113,345	1,679	72	1,574	105
2011	848	0	4,472,576	267,000	4,205,576	0	0	0	0
2012	865	0	4,566,520	267,000	4,299,521	0	0	0	0
2013	887	0	4,692,492	267,000	4,425,492	0	0	0	0

Year	Variable Costs/(Revenues)				Fixed Costs/(Revenues)				Total Annual Costs
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 45 MW CT Generation to Meet Requirements	Cost of Spot Market Energy Purchases	LEM	SEPA	45 MW CT	Capacity Deficits/ (Surplus)	
1999		$0	$0	$0		$6,088,000	$0	$0	
2000		$0	$0	$0		$6,194,000	$0	$0	
2001		$0	$0	$0		$6,194,000	$0	$0	
2002		$0	$0	$0		$6,194,000	$0	$0	
2003		$0	$0	$0		$6,194,000	$0	$0	
2004		$0	$0	$0		$6,264,000	$0	$0	
2005		$0	$0	$0		$6,403,000	$0	$0	
2006		$0	$0	$0		$6,548,000	$0	$0	
2007		$0	$0	$0		$6,695,000	$0	$0	
2008		$0	$0	$720		$6,846,000	$0	$0	
2009		$0	$6,058	$0		$7,000,000	$2,132,326	$388,800	
2010		$0	$58,395	$7,269		$7,157,000	$2,142,138	$0	
2011		$0	$0	$0		$7,318,000	$2,152,842	$739,200	
2012		$0	$0	$0		$7,483,000	$2,163,546	$0	
2013		$0	$0	$0		$7,651,000	$2,175,142	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

Case 2:
Installation of 53 MW CCT in 2002 - no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Generation from 53 MW CC (MWh)	Energy Requirement Unmet by 53 MW CC (MWh)
1999	683	0	3,764,310	267,000	3,497,310	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	0	0	0	0
2008	781	6	4,104,079	267,000	3,837,073	6	2	6	0
2009	800	25	4,212,008	267,000	3,944,843	164	18	164	0
2010	831	56	4,382,024	267,000	4,113,345	1,679	72	1,613	65
2011	848	0	4,472,576	267,000	4,205,576	0	0	0	0
2012	865	0	4,566,520	267,000	4,299,521	0	0	0	0
2013	887	0	4,692,492	267,000	4,425,492	0	0	0	0

Year	Variable Costs/(Revenues)				Fixed Costs/(Revenues)				Total Annual Costs
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 53 MW CC Generation to Meet Requirements	Cost of Spot Market Energy Purchases	LEM	SEPA	53 MW CC	Capacity Deficits/ (Surplus)	
1999		$0	$0	$0		$6,088,000	$0	$0	
2000		$0	$0	$0		$6,194,000	$0	$0	
2001		$0	$0	$0		$6,194,000	$0	$0	
2002		$0	$0	$0		$6,194,000	$3,609,830	$0	
2003		$0	$0	$0		$6,194,000	$3,638,450	$0	
2004		$0	$0	$0		$6,264,000	$3,668,130	$0	
2005		$0	$0	$0		$6,403,000	$3,698,870	$0	
2006		$0	$0	$0		$6,548,000	$3,730,670	$0	
2007		$0	$0	$0		$6,695,000	$3,764,060	$0	
2008		$0	$184	$0		$6,846,000	$3,797,980	$0	
2009		$0	$4,911	$0		$7,000,000	$3,833,490	$0	
2010		$0	$48,539	$3,122		$7,157,000	$3,870,060	$201,600	
2011		$0	$0	$0		$7,318,000	$3,907,690	$0	
2012		$0	$0	$0		$7,483,000	$3,946,910	$0	
2013		$0	$0	$0		$7,651,000	$3,987,720	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

Case 2:
Installation of 53 MW CCT in 2009 - no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Generation from 53 MW CC (MWh)	Energy Requirement Unmet by 53 MW CC (MWh)
1999	683	0	3,764,310	267,000	3,497,310	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	0	0	0	0
2006	752	0	3,945,241	267 000	3,678,241	0	0	0	0
2007	765	0	4 017 067	267 000	3 750,067	0	0	0	0
2008	781	6	4,104 079	267 000	3,837,073	6	2	0	6
2009	800	25	4 212 008	267,000	3,944,843	164	18	164	0
2010	831	56	4 382 024	267 000	4,113,345	1,679	72	1,613	65
2011	848	0	4 472 576	267 000	4,205,576	0	0	0	0
2012	865	0	4 566 520	267,000	4 299,521	0	0	0	0
2013	887	0	4 692 492	267 000	4,425,492	0	0	0	0

Year	Variable Costs/(Revenues)				Fixed Costs/(Revenues)				Total Annual Costs
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 53 MW CC Generation to Meet Requirements	Cost of Spot Market Energy Purchases	LEM	SEPA	53 MW CC	Capacity Deficits/ (Surplus)	
1999		$0	$0	$0		$6,088,000	$0	$0	
2000		$0	$0	$0		$6,194,000	$0	$0	
2001		$0	$0	$0		$6,194,000	$0	$0	
2002		$0	$0	$0		$6,194,000	$0	$0	
2003		$0	$0	$0		$6,194,000	$0	$0	
2004		$0	$0	$0		$6,264,000	$0	$0	
2005		$0	$0	$0		$6,403,000	$0	$0	
2006		$0	$0	$0		$6,548,000	$0	$0	
2007		$0	$0	$0		$6,695,000	$0	$0	
2008		$0	$0	$720		$6,846,000	$0	$388,800	
2009		$0	$4,911	$0		$7,000,000	$3,833,490	$0	
2010		$0	$48,539	$3,122		$7,157,000	$3,870,060	$201,600	
2011		$0	$0	$0		$7,318,000	$3,907,690	$0	
2012		$0	$0	$0		$7,483,000	$3,946,910	$0	
2013		$0	$0	$0		$7,651,000	$3,987,720	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

Case 3:

50 MW purchases from CC unit beginning in 2002- no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Purchases from 50 MW CC (MWh)	Energy Requirement Unmet by 50 MW CC Purchases
1999	683	0	3,784,310	287,000	3,497,310	0	0	0	0
2000	717	0	3,952,672	287,000	3,685,672	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	0	0	0	0
2008	781	6	4 104,079	267,000	3,837,073	6	2	6	0
2009	800	25	4,212 008	267,000	3 944 843	184	18	184	0
2010	831	56	4 382 024	267,000	4 113 345	1,679	72	1,601	77
2011	848	0	4 472,576	267 000	4 205 576	0	0	0	0
2012	865	0	4,566 520	267 000	4 299 521	0	0	0	0
2013	887	0	4 692 492	267 000	4 425 492	0	0	0	0

Year	Variable Costs/(Revenues)				Fixed Costs/(Revenues)				
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 50 MW CC Purchases to Meet Requirements	Cost of Spot Market Energy Purchases	LEM	SEPA	50 MW CC Purchase	Capacity Deficits/ (Surplus)	Total Annual Costs
1999		$0	$0	$0		$6,088,000	$0	$0	
2000		$0	$0	$0		$6,194,000	$0	$0	
2001		$0	$0	$0		$6,194,000	$0	$0	
2002		$0	$0	$0		$6,194,000	$3,991,384	$0	
2003		$0	$0	$0		$6,194,000	$4,131,083	$0	
2004		$0	$0	$0		$6,264,000	$4,275,671	$0	
2005		$0	$0	$0		$6,403,000	$4,425,319	$0	
2006		$0	$0	$0		$6,548,000	$4,580,205	$0	
2007		$0	$0	$0		$6,695,000	$4,740,513	$0	
2008		$0	$202	$0		$6,846,000	$4,906,430	$0	
2009		$0	$5,556	$0		$7,000,000	$5,078,156	$0	
2010		$0	$56,337	$3,984		$7,157,000	$5,255,891	$403,200	
2011		$0	$0	$0		$7,318,000	$5,439,847	$0	
2012		$0	$0	$0		$7,483,000	$5,630,242	$0	
2013		$0	$0	$0		$7,651,000	$5,827,300	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions

Case 3:
50 MW purchases from CC unit beginning in 2009- no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Purchases from 50 MW CC (MWh)	Energy Requirement Unmet by 50 MW CC Purchases
1999	683	0	3,764,310	267,000	3,497,310	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	0	0	0	0
2008	781	6	4,104,079	267,000	3,837,073	6	2	0	6
2009	800	25	4,212,008	267,000	3,944,843	164	18	164	0
2010	831	56	4,382,024	267,000	4,113,345	1,679	72	1,601	77
2011	848	0	4,472,576	267,000	4,205,576	0	0	0	0
2012	865	0	4,566,520	267,000	4,299,521	0	0	0	0
2013	887	0	4,692,492	267,000	4,425,492	0	0	0	0

	Variable Costs/(Revenues)				Fixed Costs/(Revenues)				
Year	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 50 MW CC Purchases to Meet Requirements	Cost of Spot Market Energy Purchases	LEM	SEPA	50 MW CC Purchase	Capacity Deficits/ (Surplus)	Total Annual Costs
1999		$0	$0	$0		$6,088,000	$0	$0	
2000		$0	$0	$0		$6,194,000	$0	$0	
2001		$0	$0	$0		$6,194,000	$0	$0	
2002		$0	$0	$0		$6,194,000	$0	$0	
2003		$0	$0	$0		$6,194,000	$0	$0	
2004		$0	$0	$0		$6,264,000	$0	$0	
2005		$0	$0	$0		$6,403,000	$0	$0	
2006		$0	$0	$0		$6,548,000	$0	$0	
2007		$0	$0	$0		$6,695,000	$0	$0	
2008		$0	$0	$720		$6,846,000	$0	$388,800	
2009		$0	$5,556	$0		$7,000,000	$5,078,156	$0	
2010		$0	$56,337	$3,984		$7,157,000	$5,255,891	$403,200	
2011		$0	$0	$0		$7,318,000	$5,439,847	$0	
2012		$0	$0	$0		$7,483,000	$5,630,242	$0	
2013		$0	$0	$0		$7,651,000	$5,827,300	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

Case 4:
Peaking purchases - no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Peaking Purchases (MWh)	Energy Requirement Unmet by Peaking Purchases (MWh)
1999	683	0	3,764,310	267,000	3,497,310	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	0	0	0	0
2008	781	6	4,104,079	267,000	3,837,073	6	2	0	0
2009	800	25	4,212,008	267,000	3,944,843	164	18	63	0
2010	831	56	4,382,024	267,000	4,113,345	1,679	72	347	0
2011	848	0	4,472,576	267,000	4,205,576	0	0	0	0
2012	865	0	4,566,520	267,000	4,299,521	0	0	0	0
2013	887	0	4,692,492	267,000	4,425,492	0	0	0	0

Year	Variable Costs/(Revenues)				Fixed Costs/(Revenues)			Total Annual Costs
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of Peaking Purchases to Meet Requirements	Cost of Spot Market Energy Purchases	LEM	SEPA	Peaking Purchases	
1999		$0	$0	$0		$6,088,000	$0	
2000		$0	$0	$0		$6,194,000	$0	
2001		$0	$0	$0		$6,194,000	$0	
2002		$0	$0	$0		$6,194,000	$0	
2003		$0	$0	$0		$6,194,000	$0	
2004		$0	$0	$0		$6,264,000	$0	
2005		$0	$0	$0		$6,403,000	$0	
2006		$0	$0	$0		$6,548,000	$0	
2007		$0	$0	$0		$6,695,000	$0	
2008		$0	$62	$653		$6,846,000	$388,800	
2009		$0	$8,361	$8,621		$7,000,000	$1,650,000	
2010		$0	$47,400	$91,608		$7,157,000	$3,763,200	
2011		$0	$0	$0		$7,318,000	$0	
2012		$0	$0	$0		$7,483,000	$0	
2013		$0	$0	$0		$7,651,000	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions

Case 5:
Commercial/Industrial Interruptible Rate Program - no sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Excess Available From LEM Contract (MWh)	Sales of Available Excess LEM (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	736,953	0	0
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,386	0	0
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	656,103	0	0
2008	781	6	4,104,079	267,000	3,837,073	1,392,647	612,855	6	2
2009	800	25	4,212,008	267,000	3,944,843	1,284,877	554,029	164	18
2010	831	56	4,382,024	267,000	4,113,345	1,116,375	460,798	1,679	72
2011	848	0	4,472,576	267,000	4,205,576	2,075,344	927,857	0	0
2012	865	0	4,566,520	267,000	4,299,521	2,708,479	1,222,121	0	0
2013	887	0	4,692,492	267,000	4,425,492	2,582,508	1,158,703	0	0

Year	Variable Costs/(Revenues)				Fixed Costs/(Revenues)			Total Annual Costs
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of Spot Market Energy Purchases	Cost of Load Management	LEM	SEPA	Capacity Deficits/ (Surplus)	
1999		$0	$0	$0		$6,088,000	$0	
2000		$0	$0	$0		$6,194,000	$0	
2001		$0	$0	$0		$6,194,000	$0	
2002		$0	$0	$0		$6,194,000	$0	
2003		$0	$0	$0		$6,264,000	$0	
2004		$0	$0	$0		$6,403,000	$0	
2005		$0	$0	$0		$6,548,000	$0	
2006		$0	$0	$0		$6,695,000	$0	
2007		$0	$0	$0		$6,846,000	$0	
2008		$0	$0	$360		$7,000,000	$0	
2009		$0	$0	$11,096		$7,157,000	$0	
2010		$0	$675	$82,690		$7,318,000	$1,023,765	
2011		$0	$0	$0		$7,483,000	$0	
2012		$0	$0	$0		$7,651,000	$0	
2013		$0	$0	$0			$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

Case 0:

Unmet requirements purchased from spot market with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available Surplus LEM (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	738,953	0	0
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	783,386	0	0
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	656,103	0	0
2008	781	6	4,104,079	267,000	3,837,073	1,392,647	612,855	6	2
2009	800	25	4,212,008	267,000	3,944,843	1,284,877	554,029	164	18
2010	831	56	4,382,024	267,000	4,113,345	1,116,375	460,798	1,679	72
2011	848	0	4,472,576	267,000	4,205,576	2,075,344	927,857	0	0
2012	865	0	4,566,520	267,000	4,299,521	2,708,479	1,222,121	0	0
2013	887	0	4,692,492	267,000	4,425,492	2,582,508	1,158,703	0	0

	Variable Costs/(Revenues)					Fixed Costs/(Revenues)			
Year	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of Spot Market Energy Purchases	Cost of LEM Energy Purchases for Resale	Potential Revenue from Sales of LEM Surplus	LEM	SEPA	Capacity Deficits (Surplus)	Total Annual Costs
1999		$0	$0			$0	$6,088,000	$0	
2000		$0	$0			($1,068,000)	$6,194,000	$0	
2001		$0	$0			($1,068,000)	$6,194,000	$0	
2002		$0	$0			($1,068,000)	$6,194,000	$0	
2003		$0	$0			($1,068,000)	$6,194,000	$0	
2004		$0	$0			($623,000)	$6,264,000	$0	
2005		$0	$0			$0	$6,403,000	$0	
2006		$0	$0			$0	$6,548,000	$0	
2007		$0	$0			$0	$6,695,000	$0	
2008		$0	$720			$0	$6,846,000	$0	
2009		$0	$22,192			$0	$7,000,000	$388,800	
2010		$0	$166,056			$0	$7,157,000	$1,650,000	
2011		$0	$0			($2,610,557)	$7,318,000	$3,763,200	
2012		$0	$0			($4,110,750)	$7,483,000	$0	
2013		$0	$0			($4,110,750)	$7,651,000	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Case 1:
Installation of 45 MW CT in 2002 with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available Surplus LEM (MWh)	Energy Requirements Unmet by LEM and SEPA	Number of Deficit Hours	Generation from 45 MW CT (MWh)	Energy Requirement Unmet by 45 MW CT (MWh)	Potential Energy Sales from 45 MW CT (MWh)
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	681,173	0	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	736,953	0	0	0	0	41,760
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,386	0	0	0	0	44,640
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0	0	0	49,680
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0	0	0	52,560
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0	0	0	56,160
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	658,103	0	0	0	0	59,760
2008	781	6	4,104,079	267 000	3 837,073	1,392,647	612,855	6	2	6	0	65,514
2009	800	25	4 212 008	267 000	3 944,843	1,284,877	554,029	164	18	164	0	75,436
2010	831	56	4,382 024	267 000	4,113,345	1,116,375	460,798	1,679	72	1,574	105	80,806
2011	848	0	4 472 576	267 000	4 205,576	2,075,344	927,857	0	0	0	0	82,080
2012	865	0	4 566 520	267 000	4 299 521	2,708,479	1,222,121	0	0	0	0	82,080
2013	887	0	4 692 492	267 000	4,425,492	2,582,508	1,158,703	0	0	0	0	83,520

	Variable Costs/(Revenues)								Fixed Costs/(Revenues)				
Year	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 45 MW CT Generation to Meet Requirements	Cost of Spot Market Energy Purchases	Cost of 45 MW CT Generation for Sales	Cost of LEM Energy Purchases for Resale	Potential Revenue from Sales of Surplus Generation	Potential Revenue from Sales of Available LEM Surplus *	LEM	SEPA	45 MW CT	Capacity Deficits/ (Surplus)	Total Annual Costs
1999		$0	$0	$0	$0		$0		$0	$8,088,000	$0	$0	
2000		$0	$0	$0	$0		$0		($1,068,000)	$8,194,000	$0	$0	
2001		$0	$0	$0	$0		$0		($1,068,000)	$8,194,000	$0	$0	
2002		$0	$0	$0	$1,330,056		($7,079,205)		($1,068,000)	$8,194,000	$2,069,886	($2,052,000)	
2003		$0	$0	$0	$1,459,282		($7,518,379)		($1,068,000)	$8,194,000	$2,077,914	($2,106,000)	
2004		$0	$0	$0	$1,662,790		($8,050,581)		($623,000)	$8,264,000	$2,085,942	($2,160,000)	
2005		$0	$0	$0	$1,804,910		($8,539,183)		$0	$8,403,000	$2,094,862	($2,214,000)	
2006		$0	$0	$0	$1,977,955		($9,086,560)		$0	$8,548,000	$2,103,782	($2,268,000)	
2007		$0	$0	$0	$2,153,153		($9,664,153)		$0	$8,695,000	$2,112,702	($2,322,000)	
2008		$0	$227	$0	$2,389,287		($10,353,136)		$0	$8,846,000	$2,122,068	($2,059,200)	
2009		$0	$8,058	$0	$2,778,290		($11,219,696)		$0	$7,000,000	$2,132,326	($1,080,000)	
2010		$0	$58,395	$7,269	$2,991,292		($11,886,763)		$0	$7,157,000	$2,142,138	$739,200	
2011		$0	$0	$0	$3,082,104		($12,187,583)		($2,610,557)	$7,318,000	$2,152,842	($2,538,000)	
2012		$0	$0	$0	$3,111,653		($12,338,465)		($4,110,750)	$7,483,000	$2,163,546	($2,592,000)	
2013		$0	$0	$0	$3,175,430		($12,546,121)		($4,110,750)	$7,651,000	$2,175,142	($2,646,000)	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999 The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Case 1:
Installation of 45 MW CT in 2009 with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available Surplus LEM (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Generation from 45 MW CT (MWh)	Energy Requirement Unmet by 45 MW CT (MWh)	Potential Energy Sales from 45 MW CT (MWh)
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	736,953	0	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,388	0	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,618	0	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0	0	0	0
2007	765	0	4 017,067	267 000	3 750,067	1,479,653	656,103	0	0	0	0	0
2008	781	6	4 104,079	267 000	3.837,073	1,392,647	612,855	6	2	0	0	0
2009	800	25	4 212 008	267 000	3 944,843	1,284,877	554,029	164	18	164	0	75,436
2010	831	56	4 382,024	267 000	4.113 345	1,118,375	460,798	1,679	72	1,574	105	80,606
2011	848	0	4 472 576	267 000	4 205 576	2,075,344	927,857	0	0	0	0	82,080
2012	865	0	4 566 520	267 000	4 299,521	2,708,479	1,222,121	0	0	0	0	82,080
2013	887	0	4 692 492	267 000	4 425,492	2,582,508	1,158,703	0	0	0	0	83,520

	Variable Costs/(Revenues)								Fixed Costs/(Revenues)				
Year	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 45 MW CT Generation to Meet Requirements	Cost of Spot Market Energy Purchases	Cost of 45 MW CT Generation for Sales	Cost of LEM Energy Purchases for Resale	Potential Revenue from Sales of Surplus Generation	Potential Revenue from Sales of Available LEM Surplus	LEM	SEPA	45 MW CT	Capacity Deficits/(Surplus)	Total Annual Costs
1999		$0	$0	$0	$0		$0		$0	$6,088,000	$0	$0	
2000		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2001		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2002		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2003		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2004		$0	$0	$0	$0		$0		($623,000)	$6,264,000	$0	$0	
2005		$0	$0	$0	$0		$0		$0	$6,403,000	$0	$0	
2006		$0	$0	$0	$0		$0		$0	$6,548,000	$0	$0	
2007		$0	$0	$0	$0		$0		$0	$6,695,000	$0	$0	
2008		$0	$0	$720	$0		$0		$0	$6,846,000	$0	$388,800	
2009		$0	$6,058	$0	$2,778,290		($11,219,696)		$0	$7,000,000	$2,132,326	($1,080,000)	
2010		$0	$58,395	$7,269	$2,991,292		($11,886,763)		$0	$7,157,000	$2,142,138	$739,200	
2011		$0	$0	$0	$3,082,104		($12,187,583)		($2,610,557)	$7,318,000	$2,152,842	($2,538,000)	
2012		$0	$0	$0	$3,111,653		($12,338,465)		($4,110,750)	$7,483,000	$2,163,546	($2,592,000)	
2013		$0	$0	$0	$3,175,430		($12,546,121)		($4,110,750)	$7,651,000	$2,175,142	($2,848,000)	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Case 2:
Installation of 53 MW CC in 2002 with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available Surplus LEM (MWh)	Energy Requirements Unmet by LEM and SEPA	Number of Deficit Hours	Generation from 53 MW CC (MWh)	Energy Requirement Unmet by 53 MW CC (MWh)	Potential Energy Sales from 53 MW CC (MWh)
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	738,953	0	0	0	0	93,280
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,386	0	0	0	0	96,672
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0	0	0	99,216
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0	0	0	101,760
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0	0	0	105,841
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	656,103	0	0	0	0	111,777
2008	781	6	4,104,079	267,000	3,837,073	1,392,647	612,855	6	2	6	0	121,947
2009	800	25	4,212,008	267,000	3,944,843	1,284,877	554,029	164	18	164	0	137,053
2010	831	56	4,382,024	267,000	4,113,345	1,116,375	460,788	1,679	72	1,613	65	149,265
2011	848	0	4,472,576	267,000	4,205,576	2,075,344	927,857	0	0	0	0	150,785
2012	865	0	4,566,520	267,000	4,299,521	2,708,479	1,222,121	0	0	0	0	150,785
2013	887	0	4,692,492	267,000	4,425,492	2,582,508	1,158,703	0	0	0	0	151,833

Year	Variable Costs/(Revenues)								Fixed Costs/(Revenues)				Total Annual Costs
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 53 MW CC Generation to Meet Requirements	Cost of Spot Market Energy Purchases	Cost of 53 MW CC Generation for Sales	Cost of LEM Energy Purchases for Resale	Potential Revenue from Sales of Surplus Generation	Potential Revenue from Sales of Available LEM Surplus	LEM	SEPA	53 MW CC	Capacity Deficits/ (Surplus)	
1999		$0	$0	$0	$0		$0		$0	$6,088,000	$0	$0	
2000		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2001		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2002		$0	$0	$0	$2,406,624		($9,598,258)		($1,068,000)	$6,194,000	$3,609,830	($2,416,800)	
2003		$0	$0	$0	$2,559,875		($10,152,565)		($1,068,000)	$6,194,000	$3,638,450	($2,480,400)	
2004		$0	$0	$0	$2,690,738		($10,712,438)		($823,000)	$6,264,000	$3,668,130	($2,544,000)	
2005		$0	$0	$0	$2,831,981		($11,301,544)		$0	$6,403,000	$3,698,870	($2,607,600)	
2006		$0	$0	$0	$3,020,702		($11,974,225)		$0	$6,548,000	$3,730,670	($2,671,200)	
2007		$0	$0	$0	$3,263,888		($12,737,365)		$0	$6,695,000	$3,764,060	($2,734,800)	
2008		$0	$184	$0	$3,604,747		($13,668,447)		$0	$6,846,000	$3,797,980	($2,481,600)	
2009		$0	$4,911	$0	$4,092,388		($14,780,346)		$0	$7,000,000	$3,833,490	($1,512,000)	
2010		$0	$48,539	$3,122	$4,491,395		($15,789,225)		$0	$7,157,000	$3,870,060	$201,600	
2011		$0	$0	$0	$4,592,911		($16,142,765)		($2,610,557)	$7,318,000	$3,907,690	($2,989,200)	
2012		$0	$0	$0	$4,638,147		($16,342,612)		($4,110,750)	$7,483,000	$3,946,910	($3,052,800)	
2013		$0	$0	$0	$4,679,394		($16,571,115)		($4,110,750)	$7,651,000	$3,987,720	($3,116,400)	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Case 2:
Installation of 53 MW CC in 2009 with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available Surplus LEM (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Generation from 45 MW CT (MWh)	Energy Requirement Unmet by 53 MW CC (MWh)	Potential Energy Sales from 53 MW CC (MWh)
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,981	0	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	736,953	0	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,386	0	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	656,103	0	0	0	0	0
2008	781	6	4,104,079	267,000	3,837,073	1,392,647	612,655	6	2	0	0	0
2009	800	25	4,212,008	267,000	3,944,843	1,284,877	554,029	164	18	164	0	137,053
2010	831	56	4,382,024	267,000	4,113,345	1,116,375	460,798	1,679	72	1,613	65	149,265
2011	848	0	4,472,576	267,000	4,205,576	2,075,344	927,857	0	0	0	0	150,785
2012	865	0	4,566,520	267,000	4,299,521	2,708,479	1,222,121	0	0	0	0	150,785
2013	887	0	4,692,492	267,000	4,425,492	2,582,508	1,158,703	0	0	0	0	151,633

	Variable Costs/(Revenues)								Fixed Costs/(Revenues)				
Year	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 53 MW CC Generation to Meet Requirements	Cost of Spot Market Energy Purchases	Cost of 53 MW CC Generation for Sales	Cost of LEM Energy Purchases for Resale	Potential Revenue from Sales of Surplus Generation	Potential Revenue from Sales of Available LEM Surplus	LEM	SEPA	53 MW CC	Capacity Deficits/ (Surplus)	Total Annual Costs
1999		$0	$0	$0	$0		$0		$0	$6,088,000	$0	$0	
2000		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2001		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2002		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2003		$0	$0	$0	$0		$0		($1,068,000)	$6,194,000	$0	$0	
2004		$0	$0	$0	$0		$0		($623,000)	$6,264,000	$0	$0	
2005		$0	$0	$0	$0		$0		$0	$6,403,000	$0	$0	
2006		$0	$0	$0	$0		$0		$0	$6,548,000	$0	$0	
2007		$0	$0	$0	$0		$0		$0	$6,695,000	$0	$0	
2008		$0	$0	$720	$0		$0		$0	$6,846,000	$0	$388,800	
2009		$0	$4,911	$0	$4,092,388		($14,780,346)		$0	$7,000,000	$3,833,490	($1,512,000)	
2010		$0	$48,539	$3,122	$4,491,395		($15,789,225)		$0	$7,157,000	$3,870,060	$201,800	
2011		$0	$0	$0	$4,592,911		($16,142,765)		($2,610,557)	$7,318,000	$3,907,690	($2,989,200)	
2012		$0	$0	$0	$4,638,147		($16,342,612)		($4,110,750)	$7,483,000	$3,946,910	($3,052,800)	
2013		$0	$0	$0	$4,879,394		($16,571,115)		($4,110,750)	$7,651,000	$3,987,720	($3,116,400)	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful

CASE NUMBER:

99-429

Case 3:
50 MW purchases from CC unit beginning in 2002 with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available Surplus LEM (MWh)	Energy Requirements Unmet by LEM and SEPA	Number of Deficit Hours	Purchases from 50 MW CC (MWh)	Energy Requirement Unmet by 50 MW CC	Potential Energy Sales from Excess 50 MW CC Purchase (MWh)
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	736,953	0	0	0	0	90,400
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,386	0	0	0	0	91,200
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0	0	0	92,000
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0	0	0	92,800
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0	0	0	92,800
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	656,103	0	0	0	0	95,200
2008	781	6	4,104,079	267,000	3,837,073	1,392,647	612,855	6	2	6	0	95,994
2009	800	25	4,212,008	267,000	3,944,843	1,284,877	554,029	164	18	164	0	95,836
2010	831	56	4,382,024	267,000	4,113,345	1,116,375	460,798	1,679	72	1,601	77	94,498
2011	848	0	4,472,576	267,000	4,205,576	2,075,344	927,857	0	0	0	0	92,800
2012	865	0	4,566,520	267,000	4,299,521	2,708,479	1,222,121	0	0	0	0	90,400
2013	887	0	4,692,492	267,000	4,425,492	2,582,508	1,158,703	0	0	0	0	84,000

	Variable Costs/(Revenues)								Fixed Costs/(Revenues)				
Year	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 50 MW CC Purchases to Meet Requirements	Cost of Spot Market Energy Purchases	Cost of 50 MW CC Purchases for Sales	Cost of LEM Energy Purchases for Resale	Potential Revenue from Sales of Surplus Purchases	Potential Revenue from Sales of Available LEM Surplus	LEM	SEPA	50 MW CC Purchases	Capacity Deficits/(Surplus)	Total Annual Costs
1999		$0	$0	$0	$0		$0			$6,088,000	$0	$0	
2000		$0	$0	$0	$0		$0			$6,194,000	$0	$0	
2001		$0	$0	$0	$0		$0			$6,194,000	$0	$0	
2002		$0	$0	$0	$2,298,872		($9,116,557)			$6,194,000	$3,991,384	($2,280,000)	
2003		$0	$0	$0	$2,414,976		($9,577,891)			$6,194,000	$4,131,083	($2,340,000)	
2004		$0	$0	$0	$2,537,360		($10,062,293)			$6,264,000	$4,275,671	($2,400,000)	
2005		$0	$0	$0	$2,665,216		($10,571,132)			$6,403,000	$4,425,319	($2,460,000)	
2006		$0	$0	$0	$2,775,648		($11,090,330)			$6,548,000	$4,580,205	($2,520,000)	
2007		$0	$0	$0	$2,965,480		($11,710,107)			$6,695,000	$4,740,513	($2,580,000)	
2008		$0	$202	$0	$3,114,038		($12,310,493)			$6,848,000	$4,906,430	($2,323,200)	
2009		$0	$5,556	$0	$3,237,324		($12,893,681)			$7,000,000	$5,078,156	($1,350,000)	
2010		$0	$56,337	$3,984	$3,324,449		($13,395,164)			$7,157,000	$5,255,891	$403,200	
2011		$0	$0	$0	$3,400,192		($13,601,283)			$7,318,000	$5,439,847	($2,820,000)	
2012		$0	$0	$0	$3,449,664		($13,678,957)			$7,483,000	$5,630,242	($2,880,000)	
2013		$0	$0	$0	$3,338,160		($13,597,228)			$7,651,000	$5,827,300	($2,940,000)	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Case 3:
50 MW purchases from CC unit beginning in 2009 with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available Surplus LEM (MWh)	Energy Requirements Unmet by LEM and SEPA	Number of Deficit Hours	Purchases from 50 MW CC (MWh)	Energy Requirement Unmet by 50 MW CC	Potential Energy Sales from Excess 50 MW CC Purchase (MWh)
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	736,953	0	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,386	0	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,189	0	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	656,103	0	0	0	0	0
2008	781	6	4,104,079	267,000	3,837,073	1,392,647	612,855	0	0	0	0	0
2009	800	25	4,212,008	267,000	3,944,843	1,284,877	554,029	8	2	0	0	95,836
2010	831	56	4,382,024	267,000	4,113,345	1,116,375	460,798	164	18	164	0	94,498
2011	848	0	4,472,576	267,000	4,205,576	2,075,344	927,857	1,679	72	1,601	77	92,800
2012	865	0	4,566,520	267,000	4,299,521	2,708,479	1,222,121	0	0	0	0	90,400
2013	887	0	4,692,492	267,000	4,425,492	2,582,508	1,158,703	0	0	0	0	84,000

	Variable Costs/(Revenues)								Fixed Costs/(Revenues)				
Year	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of 50 MW CC Purchases to Meet Requirements	Cost of Spot Market Energy Purchases	Cost of 50 MW CC Purchases for Sales	Cost of LEM Energy Purchases for Resale	Potential Revenue from Sales of Surplus Purchases	Potential Revenue from Sales of Available LEM Surplus	LEM	SEPA	50 MW CC Purchases	Capacity Deficits/ (Surplus)	Total Annual Costs
1999		$0	$0	$0	$0		$0			$8,088,000	$0	$0	
2000		$0	$0	$0	$0		$0			$8,194,000	$0	$0	
2001		$0	$0	$0	$0		$0			$8,194,000	$0	$0	
2002		$0	$0	$0	$0		$0			$8,194,000	$0	$0	
2003		$0	$0	$0	$0		$0			$8,194,000	$0	$0	
2004		$0	$0	$0	$0		$0			$8,264,000	$0	$0	
2005		$0	$0	$0	$0		$0			$8,403,000	$0	$0	
2006		$0	$0	$0	$0		$0			$8,548,000	$0	$0	
2007		$0	$0	$0	$0		$0			$8,695,000	$0	$0	
2008		$0	$0	$720	$0		$0			$8,846,000	$0	$388,800	
2009		$0	$5,556	$0	$3,237,324		($12,893,681)			$7,000,000	$5,078,156	($1,350,000)	
2010		$0	$56,337	$3,984	$3,324,449		($13,395,164)			$7,157,000	$5,255,891	$403,200	
2011		$0	$0	$0	$3,400,192		($13,601,283)			$7,318,000	$5,439,847	($2,820,000)	
2012		$0	$0	$0	$3,449,664		($13,678,957)			$7,483,000	$5,630,242	($2,880,000)	
2013		$0	$0	$0	$3,338,160		($13,597,228)			$7,651,000	$5,827,300	($2,940,000)	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have *summer peak prices similar to those realized* in 1998 and 1999. The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels. The revenues shown in this table reflect the sale of *all excess energy* available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful.

Case 4:
Peaking purchases with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available Surplus LEM (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours	Peaking Purchases (MWh)	Energy Requirement Unmet by Peaking Purchases (MWh)	Potential Energy Sales from Excess Peaking Purchases (MWh)
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0	0	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0	0	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0	0	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	736,953	0	0	0	0	0
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,386	0	0	0	0	0
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0	0	0	0
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0	0	0	0
2006	752	0	3,945,241	267,000	3,678,241	1,551,479	692,089	0	0	0	0	0
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	656,103	0	0	0	0	0
2008	781	6	4,104 079	267,000	3 837 073	1,392,647	612,855	6	2	0	0	12,800
2009	800	25	4,212 008	267 000	3 944 843	1,284,877	554,029	164	18	63	0	12,737
2010	831	56	4 382 024	267 000	4,113,345	1,116,375	460,798	1,679	72	347	1	12,453
2011	848	0	4 472 576	267 000	4 205 576	2,075,344	927,857	0	0	0	0	0
2012	865	0	4 566 520	267 000	4 299 521	2,708,479	1,222,121	0	0	0	0	0
2013	887	0	4 692 492	267 000	4 425 492	2,582,508	1,158,703	0	0	0	0	0

	Variable Costs/(Revenues)								Fixed Costs/(Revenues)			
Year	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of Peaking Purchases to Meet Requirements	Cost of Spot Market Energy Purchases	Cost of Peaking Purchases for Sales	Cost of LEM Energy Purchases for Resale	Potential Revenue from Sales of Surplus Peaking Purchases	Potential Revenue from Sales of Available LEM Surplus	LEM	SEPA	Peaking Purchases	Total Annual Costs
1999		$0	$0	$0	$0		$0			$6,088,000	$0	
2000		$0	$0	$0	$0		$0			$6,194,000	$0	
2001		$0	$0	$0	$0		$0			$6,194,000	$0	
2002		$0	$0	$0	$0		$0			$6,194,000	$0	
2003		$0	$0	$0	$0		$0			$6,194,000	$0	
2004		$0	$0	$0	$0		$0			$6,264,000	$0	
2005		$0	$0	$0	$0		$0			$6,403,000	$0	
2006		$0	$0	$0	$0		$0			$6,548,000	$0	
2007		$0	$0	$0	$0		$0			$6,695,000	$0	
2008		$0	$62	$653	$1,628,482		($8,418,621)			$6,846,000	$388,800	
2009		$0	$8,361	$8,621	$1,677,143		($8,818,600)			$7,000,000	$1,650,000	
2010		$0	$47,400	$91,608	$1,697,191		($9,191,667)			$7,157,000	$3,763,200	
2011		$0	$0	$0	$0		$0			$7,318,000	$0	
2012		$0	$0	[illegible]	$0		$0			$7,483,000	$0	
2013		$0	$0	$0	$0		$0			$7,651,000	$0	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999 The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful

Case 5:

Commercial/Industrial Interruptible Rate Program with sales of available surplus

Year	Projected Big Rivers Load (MW)	Capacity Deficit (MW)	Projected Big Rivers Energy Requirements (MWh)	Energy From SEPA Contract (MWh)	Energy From LEM Contract (MWh)	Total Surplus Available From LEM Contract (MWh)	Sales of Available SurplusLEM (MWh)	Energy Requirements Unmet by LEM and SEPA (MWh)	Number of Deficit Hours
1999	683	0	3,764,310	267,000	3,497,310	1,513,410	559,534	0	0
2000	717	0	3,952,672	267,000	3,685,672	1,325,048	475,961	0	0
2001	673	0	3,736,992	267,000	3,469,993	1,759,727	661,173	0	0
2002	689	0	3,599,696	267,000	3,332,696	1,897,024	738,953	0	0
2003	705	0	3,687,188	267,000	3,420,187	1,809,533	763,386	0	0
2004	720	0	3,766,563	267,000	3,499,563	1,730,157	764,616	0	0
2005	735	0	3,852,240	267,000	3,585,240	1,644,480	730,169	0	0
2006	752	0	3 945,241	267,000	3,678,241	1,551,479	692,089	0	0
2007	765	0	4,017,067	267,000	3,750,067	1,479,653	656,103	0	0
2008	781	.6	4 104,079	267 000	3 837,073	1,392,647	612,855	6	2
2009	800	25	4 212,008	267 000	3 944 843	1,284,877	554,029	164	18
2010	831	56	4 382,024	267 000	4 113,345	1,118,375	460,798	1,679	72
2011	848	0	4 472 576	267 000	4 205 576	2,075,344	927,857	0	0
2012	865	0	4 566 520	267 000	4,299,521	2,708,479	1,222,121	0	0
2013	887	0	4 692 492	267 000	4 425 492	2,582,508	1,158,703	0	0

Year	Variable Costs/(Revenues)						Fixed Costs/(Revenues)		
	LEM Cost of Energy Purchases [1]	SEPA Cost of Energy Purchases	Cost of Spot Market Energy Purchases	Cost of LEM Energy Purchases for Resale	Benefit of Interruptible Contract	Potential Revenue from Sales of LEM Surplus	LEM	SEPA	Total Annual Costs
1999		$0	$0		$0			$6,088,000	
2000		$0	$0		($723,622)			$6,194,000	
2001		$0	$0		($1,011,402)			$6,194,000	
2002		$0	$0		($1,325,279)			$6,194,000	
2003		$0	$0		($1,667,101)			$6,194,000	
2004		$0	$0		($2,038,835)			$6,264,000	
2005		$0	$0		($2,442,572)			$6,403,000	
2006		$0	$0		($2,562,538)			$6,548,000	
2007		$0	$0		($2,688,396)			$6,695,000	
2008		$0	$720		($2,820,436)			$6,846,000	
2009		$0	$22,192		($2,958,961)			$7,000,000	
2010		$0	$166,056		($3,104,289)			$7,157,000	
2011		$0	$0		($3,142,720)			$7,318,000	
2012		$0	$0		($3,181,627)			$7,483,000	
2013		$0	$0		($3,221,015)			$7,651,000	

[1] Based on rates outlined in LEM contract, subject to change based on contract provisions.

The projected revenues shown in this table are aggressive and depend on the projected spot market pricing for electricity continuing to have summer peak prices similar to those realized in 1998 and 1999 The addition of merchant power plants in the Midwest in the next few years could result in a reduction of spot market energy costs to prices closer to historical levels The revenues shown in this table reflect the sale of all excess energy available to Big Rivers at the spot market prices seen over the past two years. The likelihood of obtaining this level of revenue is doubtful

Appendix E

Sample Interruptible Tariff

INTERIM
INTERRUPTIBLE STANDBY AND SUPPLEMENTAL SERVICE
(OPTIONAL)

RATE SCHEDULE: ISST-1

AVAILABLE:

In all territory served by the Company. Service under this rate schedule is on a customer by customer basis subject to the completion of arrangements necessary for implementation.

LIMITATION OF AVAILABILITY:

The availability of this schedule to Customers who have not yet signed an Interruptible Standby and Supplemental Service Agreement may be restricted from time to time.

This schedule may be modified or withdrawn subject to determinations made under Commission Rule 25-6.0438, F.A.C., Non-Firm Electric Service - Terms and Conditions or any other Commission determination.

APPLICATION:

A Customer who is eligible to receive service under the Standby and Supplemental Service (SST-1) rate schedule may, as an option, take service under this rate schedule.

Customers taking service under this rate schedule shall enter into an Interruptible Standby and Supplemental Service Agreement ("Agreement").

SERVICE:

Three phase, 60 hertz, and at the available standard voltage.

All Customer load served under this schedule, both Standby and Supplemental, is subject to interruption by the Company and shall be separately metered from the non-interruptible, or firm, portion of the Customer's load. Transformation Rider-TR, where applicable, shall only apply to the Customer's Contract Standby Demand for delivery voltage below 69 kv. Resale of service is not permitted hereunder.

MONTHLY RATE:

STANDBY SERVICE

Delivery Voltage:	Distribution Below 69 kv	Transmission 69 kv & Above
Customer Charge:	$ 625.00	$3,225.00
Demand Charge:		
Distribution Demand Charge per kw of Contract Standby Demand	$ 2.43	none
Reservation Demand Charge per kw	$ 0.16	$ 0.15
Daily Demand Charge per kw for each daily maximum On-Peak Standby Demand	$ 0.07	$ 0.07
Energy Charge:		
On-Peak Period Non-fuel charge per kwh	1.166¢	.942¢
Off-Peak Period Non-fuel charge per kwh	1.166¢	.942¢

(Continued on Sheet No. 8.761)

(Continued from Sheet No. 8.760)

The Demand Charge for Standby Service shall be (1) the charge for Distribution Demand plus (2) the greater of the sum of the Daily Demand Charges or the Reservation Demand Charge times the maximum On-Peak Standby Demand actually registered during the month plus (3) the Reservation Demand Charge times the difference between the Contract Standby Demand and the maximum On-Peak Standby Demand actually registered during the month.

Minimum: The Customer Charge plus the Demand Charge.

Fuel Charge	See Sheet No. 8.830
Tax Clause	See Sheet No. 8.840
Conservation Charge	See Sheet No. 8.860
Oil Backout Charge	See Sheet No. 8.880
Franchise Fee	See Sheet No. 8.890

SUPPLEMENTAL SERVICE

Supplemental Service shall be the total power supplied by the Company minus the Standby Service supplied by the Company during the same metering period. The charge for all Supplemental Service shall be calculated by applying the applicable retail interruptible rate schedule, excluding the customer charge.

INTERRUPTION:

The Customer's load served under this rate schedule is subject to interruption without notice when such interruption alleviates any emergency conditions or capacity shortages, either power supply or transmission, or whenever system load, actual or projected, requires the peaking operation of the Company's generators.

The Company may interrupt the Customer's service from time to time for testing purposes. Testing purposes include the testing of the interrupting equipment and the ability of the Customer to perform. There will be at least one interruption each calendar year.

The Customer shall be responsible for providing and maintaining the appropriate equipment required to allow the Company to electrically interrupt the Customer's load, as specified in the Interruptible Standby and Supplemental Service Agreement.

RATING PERIODS:

On-Peak:

November 1 through March 31: Mondays through Fridays during the hours from 6 a.m. to 10 a.m. and 6 p.m. to 10 p.m. excluding Thanksgiving Day, Christmas Day, and New Year's Day.

April 1 through October 31: Mondays through Fridays during the hours from 12 noon to 9 p.m. excluding Memorial Day, Independence Day, and Labor Day.

Off-Peak:

All other hours.

CONTRACT STANDBY DEMAND:

The level of Customer's load requiring Interruptible Standby Service as specified in the Agreement. This Contract Standby Demand will not be less than the maximum interruptible load actually served by the Customer's generation during the current month or prior 23-month period less the amount specified as the Customer's load which would not have to be served by the Company in the event of an outage of the Customer's generating equipment. For a Customer receiving only standby service as identified under Special Provisions, the Contract Standby Demand shall be the maximum load actually served by the Company during the current month or prior 23-month period.

(Continued on Sheet No. 8.762)

(Continued from Sheet No. 8.761)

STANDBY DEMAND:

When the Customer's generation is supplying less than the minimum amount of interruptible load as specified in the Agreement, the Standby Demand is the lesser of (1) the Contract Standby Demand minus the Customer's load being served by the Customer's generation, but not less than zero, or (2) the level of Demand being supplied by the Company.

DEMAND:

Demand is the kw to the nearest whole kw, as determined by the Company's time of use metering equipment for a 30-minute period as adjusted for power factor.

TERM OF SERVICE:

Service under this rate schedule shall be for an initial term of ten (10) years, subject to Limitation of Availability, and shall continue thereafter until terminated by either the Company or the Customer upon written notice given at least five (5) years prior to termination.

Transfers, with less than five years' written notice, to any firm retail rate schedule for which the Customer would qualify may be permitted if it can be shown that such transfer is in the best interests of the Customer, the Company and the Company's other ratepayers.

If the Customer no longer wishes to receive electric service in any form from the Company, the Customer may terminate the Interruptible Standby and Supplemental Service Agreement by giving thirty (30) days' advance written notice to the Company.

The Company may terminate service under this rate schedule at any time for the Customer's failure to comply with the terms and conditions of this rate schedule or the Interruptible Standby and Supplemental Service Agreement. Prior to any such termination, the Company shall notify the Customer at least ninety (90) days in advance and describe the Customer's failure to comply. The Company may then terminate this service under this rate schedule at the end of the 90-day notice period unless the Customer takes measures necessary to eliminate, to the Company's satisfaction, the compliance deficiencies described by the Company. Notwithstanding the foregoing, if, at any time during the 90-day period, the Customer either refuses or fails to initiate and pursue corrective action, the Company shall be entitled to suspend forthwith the monthly billing under this rate schedule and bill the Customer under the otherwise applicable firm service rate schedule.

CHARGES FOR TERMINATING SERVICE OR TRANSFERRING TO FIRM SERVICE:

If service is terminated by the Company or if the Customer terminates service or transfers to a firm service rate schedule during the initial term of ten (10) years or without providing at least five (5) years' written notice, the Customer will be:

1. rebilled under the otherwise applicable firm service rate schedule for (a) the prior sixty (60) months or (b) the number of months the Customer has been billed under this rate schedule, whichever is less, and

2. billed a penalty charge of $1.00 per kw times the number of months rebilled in No. 1 above times the current Maximum Demand.

If the Customer is required to transfer to another retail rate schedule as a result of Commission Rule 25-6.0438, F.A.C., the Customer will not be rebilled.

(Continued on Sheet No. 8.763)

(Continued from Sheet No. 8.762)

SPECIAL PROVISIONS:

The Customer will allow the Company to make all necessary arrangements to meter (1) the amounts of demand and energy supplied by the Company, (2) the gross demand and energy output of the Customer's generation equipment to the interruptible load served by the Customer and, if the Customer is interconnected and operating electric generating equipment in parallel with the Company's system, (3) the capacity and energy supplied to the Company by the Customer's generating equipment. The Company shall provide and the Customer shall be required to pay the installation, operation and maintenance costs incurred by the Company for the metering equipment required in (2) and (3) described above. The Company shall retain ownership of all metering equipment.

Where the Customer and the Company agree that the Customer's interruptible service requirements are totally standby or totally supplemental, the Company shall bill the Customer accordingly and not require Company metering of the gross demand and energy output of the Customer's generating equipment provided that where only standby service is taken, (1) the Customer and the Company agree to the maximum amount of interruptible standby service to be provided by the Company and (2) the Customer agrees to and provides to the Company such data and information from the Customer's generating equipment from its own metering as is necessary to permit analysis and reporting of the load and usage characteristics of Interruptible Standby and Supplemental Sevice.

The Customer shall grant the Company reasonable access for installing, maintaining, inspecting, testing and/or removing Company-owned interrupting equipment.

It shall be the responsibility of the Customer to determine that all electrical equipment to be interrupted is in good repair and working condition. The Company will not be responsible for the repair, maintenance or replacement of the Customer's electrical equipment.

RULES AND REGULATIONS:

Service under this schedule is subject to orders of governmental bodies having jurisdiction and to the currently effective "General Rules and Regulations for Electric Service" on file with the Florida Public Service Commission. In case of conflict between any provision of this schedule and said "General Rules and Regulations for Electric Service," the provision of this schedule shall apply.

Appendix F

Economy Energy Price Forecast

Table A10. Electricity Trade
(Billion Kilowatthours, Unless Otherwise Noted)

Electricity Trade	Reference Case							Annual Growth 1997-2020 (percent)
	1996	1997	2000	2005	2010	2015	2020	
Interregional Electricity Trade								
Gross Domestic Firm Power Sales	173.4	190.3	167.9	152.3	148.6	148.6	148.6	-1.1%
Gross Domestic Economy Sales	65.2	87.6	78.5	78.3	67.2	78.4	83.9	-0.2%
Gross Domestic Trade	**238.6**	**277.9**	**246.4**	**230.7**	**215.8**	**227.0**	**232.5**	**-0.8%**
Gross Domestic Firm Power Sales (million 1997 dollars)	8148.5	8942.1	7890.5	7158.7	6983.5	6983.5	6983.5	-1.1%
Gross Domestic Economy Sales (million 1997 dollars)	1557.6	2186.7	1705.6	1848.6	1730.9	1843.5	1839.1	-0.7%
Gross Domestic Sales (million 1997 dollars)	**9706.1**	**11128.9**	**9596.0**	**9007.3**	**8714.5**	**8827.0**	**8822.6**	**-1.0%**
International Electricity Trade								
Firm Power Imports From Canada and Mexico[1]	26.1	23.9	36.0	19.3	19.3	19.3	19.3	-0.9%
Economy Imports From Canada and Mexico[1]	20.7	18.0	22.2	34.7	32.8	29.9	29.6	2.2%
Gross Imports From Canada and Mexico[1]	**46.8**	**42.0**	**58.1**	**54.0**	**52.2**	**49.2**	**49.0**	**0.7%**
Firm Power Exports To Canada and Mexico	2.8	4.7	8.9	14.1	14.1	14.1	14.1	4.9%
Economy Exports To Canada and Mexico	6.4	5.3	6.4	7.0	7.7	7.7	7.7	1.6%
Gross Exports To Canada and Mexico	**9.3**	**10.0**	**15.3**	**21.1**	**21.8**	**21.8**	**21.8**	**3.4%**

[1]Historically electric imports were primarily from renewable resources, principally hydroelectric.

Note: Totals may not equal sum of components due to independent rounding. Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems. Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

Sources: 1996 and 1997 interregional electricity trade data: Energy Information Administration (EIA), Bulk Power Data System. 1996 and 1997 international electricity trade data: DOE Form FE-718R, "Annual Report of International Electrical Export/Import Data." 1996 and 1997 Firm/economy share: National Energy Board, *Annual Report 1993*. 1996 and 1997 Planned interregional and international firm power sales: DOE Form IE-411, "Coordinated Bulk Power Supply Program Report," April 1995. **Projections:** EIA, AEO99 National Energy Modeling System run AEO99B.D100198A.

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

December 10, 1999

To: All parties of record

RE: Case No. 1999-429

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

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/hv
Enclosure

David A. Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42419 0024

John Stapleton
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

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

Honorable James M. Miller
Counsel for Big Rivers Electric
Sullivan, Mountjoy, Stainback &
Miller, P.S.C.
100 St. Ann Street
P.O. Box 727
Owensboro, KY 42302 0727

Honorable Douglas Beresford
Counsel for Big Rivers Electric
Long, Aldridge & Norman
Suite 600
701 Pennsylvania Avenue
Washington, DC 20004

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE FILING BY BIG RIVERS ELECTRIC CORPORATION OF ITS 1999 INTEGRATED RESOURCE PLAN	)))	CASE NO. 99-429

<u>O R D E R</u>

On November 22, 1999, Big Rivers Electric Corporation ("Big Rivers") submitted a request for an extension of time, from November 22, 1999 to March 22, 2000, in which to file its 1999 Integrated Resource Plan ("IRP") with the Commission. Big Rivers cites continued delays by its outside consultant, Burns & McDonnell, in preparing a satisfactory final IRP. Significant changes in the nature of its operations since its last IRP filing are the primary reasons given by Big Rivers for its request.

Big Rivers cites the fact that it no longer operates its own generating facilities, but purchases a large portion of its energy requirements from LG&E Energy Marketing, Inc. It also points to the fact that it no longer provides wholesale power to serve the loads of the large aluminum smelters that historically have accounted for one-third of its system load. For these reasons, Big Rivers asserts that this IRP filing will be unlike its previous IRP filings and, therefore, requires additional time and effort before it can be completed to the satisfaction of Big Rivers' management, the management of its three member distribution cooperatives, and the Big Rivers Board of Directors, all of which must approve the IRP before it is filed with the Commission.

After consideration of the request, and being otherwise sufficiently advised, the Commission finds compelling reasons to warrant the extension of time requested by Big Rivers.

IT IS THEREFORE ORDERED that Big Rivers' IRP, which had been scheduled to filed by November 22, 1999, shall be filed on or before March 22, 2000.

Done at Frankfort, Kentucky, this 10th day of December, 1999.

By the Commission

ATTEST:

Executive Director

RECEIVED
NOV 24 1999
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF	)	**CASE NO. 99-429**
BIG RIVERS ELECTRIC CORPORATION	)	

ENTRY OF APPEARANCE

Please take notice that Big Rivers Electric Corporation ("Big Rivers") will be represented by the following counsel in this matter, and that all pleadings, orders, and other communications should be served on Big Rivers' counsel at the addresses indicated below: ✓ JH.

James M. Miller
Sullivan, Mountjoy, Stainback & Miller, P.S.C.
100 St. Ann Street, P.O. Box 727
Owensboro, Kentucky 42302-0727
Phone (270) 926-4000
Facsimile (270) 683-6694
E-mail: millerjames@mindspring.com

Douglas Beresford
Long, Aldridge & Norman
Suite 600, 701 Pennsylvania Avenue
Washington, D.C. 20004
Phone (202) 624-1200
Facsimile (202) 624-1298

This 22d day of November, 1999.

James M. Miller

James M. Miller
Sullivan, Mountjoy, Stainback
& Miller, P.S.C.
100 St. Ann Street, P.O. Box 727
Owensboro, KY 42302-0727

Counsel for Big Rivers Electric Corporation

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing Entry of Appearance by regular mail, postage prepaid, to the following on this 22d day of November, 1999.

Iris Skidmore, Esq.
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, Kentucky 40601
Counsel for Natural Resources
and Environmental Protection

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

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

James M. Miller

James M. Miller

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

November 23, 1999

To: All parties of record

RE: Case No. 1999-429

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

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

David Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42420

John Stapleton
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE FILING BY BIG RIVERS ELECTRIC CORPORATION OF ITS 1999 INTEGRATED RESOURCE PLAN	)))	CASE NO. 99-429

ORDER

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

IT IS HEREBY ORDERED that:

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

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

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

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

By the Commission

ATTEST:

Executive Director

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

November 23, 1999

To: All parties of record

RE: Case No. 1999-429

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

Sincerely,

Stephanie J. Bell

Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

David Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY 42420

John Stapleton
663 Teton Trail
Frankfort, KY 40601

Hon. Iris Skidmore
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

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

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE FILING BY BIG RIVERS ELECTRIC CORPORATION OF ITS 1999 INTEGRATED RESOURCE PLAN	)))	CASE NO. 99-429

ORDER

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

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

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

By the Commission

ATTEST:

Helen C. Helton

Executive Director

Big Rivers Electric Corporation

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
502·827·2561
www.bigrivers.com

RECEIVED
NOV 2 2 1999
PUBLIC SERVICE COMMISSION

November 19, 1999

Ms. Helen Helton
Executive Director
Kentucky Public Service Commission
P. O. Box 615
Frankfort, KY 40602

RE: Big Rivers Electric Corporation
Case No. 99-429

Dear Ms. Helton:

On October 22, 1999, the Commission granted Big Rivers a change in its Integrated Resource Plan (IRP) filing schedule from October 21, 1999, to November 22, 1999. Big Rivers is unable to meet the November 22, 1999, filing date.

Due to a continued delay in completing the IRP by our contractor (Burns & McDonnell), Big Rivers is requesting an extension of time in which to file the 1999 IRP with the Commission. As the Commission is aware, Big Rivers no longer operates its generating facilities, but now purchases a portion of its energy requirements from LG&E Energy Marketing, Inc. Additionally, Big Rivers no longer provides wholesale power to Kenergy to service Alcan and NSA. Because of these changed circumstances, this IRP is unlike our previous IRP filings and is unlike any filed by the other utilities in Kentucky.

Big Rivers is not comfortable that the first draft of the IRP provided to Big Rivers properly and fully incorporated these type of provisions. Discussions with Burns & McDonnell and with Big Rivers' management have resulted in this request for the following reasons:

1. It is absolutely necessary that Big Rivers' senior management is comfortable with the IRP. This will take some time, especially in light of the work load at Big Rivers, the cases currently pending before the Commission and the time necessary to ensure completeness.

2. It is important that Big Rivers' three member distribution cooperation have an opportunity to review the final drafts and become comfortable with the IRP. This takes additional time.

3. Once the IRP is complete it must be approved by Big Rivers' Board of Directors prior to filing with the Commission.

4. The Thanksgiving and Christmas holidays are very near with people taking time off to spend with their families.

Big Rivers respectfully requests the Commission to change the schedule for filing its IRP from November 22, 1999, to March 22, 2000. I apologize for any inconvenience this may cause the Commission.

Sincerely,

BIG RIVERS ELECTRIC CORPORATION

David Spainhoward

David A. Spainhoward
Vice President Contract Administration and Regulatory Affairs

pm

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

NOV 1 6 1999

PUBLIC SERVICE COMMISSION

In the Matter of:

THE INTEGRATED RESOURCE PLAN OF)
BIG RIVERS ELECTRIC COPRPORATION) CASE NO. 99-429

MOTION

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

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

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

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

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

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

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

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

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

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

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

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

Respectfully submitted,

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

COUNSEL FOR NATURAL RESOURCES
AND ENVIRONMENTAL PROTECTION

CERTIFICATE OF SERVICE

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

Mr. David Spainhoward
Vice President
Big Rivers Electric Corporation
P.O. Box 24
Henderson, Kentucky 42419-0024

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

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

Iris Skidmore

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION

RECEIVED NOV 1 0 1999 PUBLIC SERVICE COMMISSION

IN RE THE MATTER OF:

THE INTEGRATED RESOURCE	)	
PLAN OF BIG RIVERS	)	Case No. 99-429
ELECTRIC CORPORATION	)	

MOTION TO INTERVENE

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

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

NOTICE OF FILING AND CERTIFICATE OF SERVICE

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

David Spainhoward

Vice President Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY. 42420

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

October 22, 1999

David Spainhoward
Vice President
Big Rivers Electric Corporation
201 Third Street
P. O. Box 24
Henderson, KY. 42420

RE: Case No. 99-429

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

Sincerely,

Stephanie Bell
Stephanie Bell
Secretary of the Commission

SB/sa
Enclosure

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter Of:

THE FILING BY BIG RIVERS ELECTRIC CORPORATION OF ITS 1999 INTEGRATED RESOURCE PLAN	)))	CASE NO. 99-429

<u>O R D E R</u>

Big Rivers Electric Corporation ("Big Rivers") requests that the Commission grant an extension of time, from October 21, 1999 to November 22, 1999, to allow Big Rivers to file its 1999 Integrated Resource Plan ("IRP") with the Commission. Big Rivers' request is pursuant to Commission Regulation 807 KAR 5:058, Section 2(1)(c), which permits the Commission to modify utility IRP filing schedules "for good cause shown."

Big Rivers states that the outside consultant on its IRP has indicated it will not be able to meet the scheduled submission date for a Power Requirements Study (load forecast) and the IRP to Big Rivers for review prior to the scheduled October 21, 1999 filing date with the Commission. Big Rivers enclosed a copy of a letter from its consultant stating the need for additional time to complete its work and asking that Big Rivers file a request for an extension of time with the Commission.

Upon consideration of the request, and being otherwise sufficiently advised, the Commission finds there is sufficient justification to grant the request for an extension of time until November 22, 1999 to allow Big Rivers to file its 1999 IRP.

IT IS THEREFORE ORDERED that Big Rivers' IRP, previously scheduled to be filed by October 21, 1999, shall be filed on or before November 22, 1999.

Done at Frankfort, Kentucky, this 22nd day of October, 1999.

By the Commission

ATTEST:

Executive Director

Big Rivers Electric Corporation

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
502-827-2561
www.bigrivers.com

October 18, 1999

RECEIVED
OCT 20 1999
PUBLIC SERVICE COMMISSION

Ms. Helen Helton
Executive Director
Kentucky Public Service Commission
P. O. Box 615
Frankfort, KY 40602

RE: Big Rivers Electric Corporation
Case No. 97-296 Integrated Resource Plan

Dear Ms. Helton:

CASE 99-429

On September 24, 1998, the Commission granted Big Rivers a change in its IRP filing schedule from April 21, 1999, to October 21, 1999. Due to a delay in completing the Power Requirements Study (PRS), Burns & McDonnell, the contractor for both the PRS and the Integrated Resource Plan, is having difficulty meeting the submission date to Big Rivers. Big Rivers is consequently unable to meet the October 21, 1999, filing date.

We respectfully ask the Commission to change the schedule for Big Rivers to file its IRP from October 21, 1999, to November 22, 1999. I have enclosed a copy of the letter from Burns & McDonnell requesting the extension of time. I apologize for any inconvenience this may cause the Commission.

Sincerely,

BIG RIVERS ELECTRIC CORPORATION

David A. Spainhoward /p.m.

David A. Spainhoward
Vice President
Contract Administration and Regulatory Affairs

pm
Enclosure
c: Mr. Mike Core
James M. Miller, Esq.
Mr. James M. Flucke
Ms. Susan Hutcherson

OCT 18 '99 10:04 FR BIG RIVERS GM 15028274882 TO 15025643460 P.02/03

(FAX)

Big Rivers
Electric Corporation

201 Third Street
P.O. Box 24
Henderson, KY 42419-0024
502-827-2561
www.bigrivers.com

RECEIVED
OCT 19 1999
PUBLIC SERVICE
COMMISSION

October 18, 1999

Ms. Helen Helton
Executive Director
Kentucky Public Service Commission
P. O. Box 615
Frankfort, KY 40602

RE: Big Rivers Electric Corporation
Case No. 97-296 Integrated Resource Plan

Dear Ms. Helton:

Case 99-429

On September 24, 1998, the Commission granted Big Rivers a change in its IRP filing schedule from April 21, 1999, to October 21, 1999. Due to a delay in completing the Power Requirements Study (PRS), Burns & McDonnell, the contractor for both the PRS and the Integrated Resource Plan, is having difficulty meeting the submission date to Big Rivers. Big Rivers is consequently unable to meet the October 21, 1999, filing date.

We respectfully ask the Commission to change the schedule for Big Rivers to file its IRP from October 21, 1999, to November 22, 1999. I have enclosed a copy of the letter from Burns & McDonnell requesting the extension of time. I apologize for any inconvenience this may cause the Commission.

Sincerely,

BIG RIVERS ELECTRIC CORPORATION

David A. Spainhoward /p.m.

David A. Spainhoward
Vice President
Contract Administration and Regulatory Affairs

pm
Enclosure
c: Mr. Mike Core
James M. Miller, Esq.
Mr. James M. Flucke
Ms. Susan Hutcherson

Burns & McDonnell 100 1898 • 1998

RECEIVED OCT 18 1999 BIG RIVERS ELECTRIC CORPORATION

RECEIVED OCT 19 1999 PUBLIC SERVICE COMMISSION

October 15, 1999

Mr. David Spainhoward
Vice President, Contract Administration and Regulatory Affairs
Big Rivers Electric Corporation
P.O. Box 24
Henderson, KY 42419-0024

Big Rivers Electric Corporation
Request for Extension for Submittal of the Integrated Resource Plan

Dear Mr. Spainhoward:

This letter is to petition Big Rivers to request an extension of the deadline for filing the Big Rivers 1999 Integrated Resource Plan with the Kentucky Public Service Commission. Due to delays in the development of the Power Requirements Study, we will not be able to provide Big Rivers with a planning study that both meets the requirements of the Public Service Commission and is a thorough and high quality product for Big Rivers to use in its planning efforts. We believe that a short extension of the deadline will allow us to provide this type of study to Big Rivers and the Public Service Commission. We ask that Big Rivers seek an extension of the deadline until the 22nd of November.

In the event that the request for an extension is not granted, Burns & McDonnell could provide a partial study on the submission deadline with a final and completed report to be submitted by the 22nd of November.

If you require any additional information, please do not hesitate to call me at 816-822-3908.

Sincerely,

James M. Flucke

James M. Flucke, P.E.
Project Manager

Cc: Bill Yeary, Big Rivers Electric Corporation

ENGINEERS • ARCHITECTS • CONSULTANTS
9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816 333-9400
Fax: 816 333-3690
http://www.burnsmcd.com

SULLIVAN, MOUNTJOY, STAINBACK & MILLER PSC

ATTORNEYS AT LAW

Ronald M. Sullivan
Jesse T. Mountjoy
Frank Stainback
James M. Miller
Michael A. Fiorella
William R. Dexter
Allen W. Holbrook
R. Michael Sullivan
P. Marcum Willis
Bryan R. Reynolds
Mark Luckett

RECEIVED
JUN 19 2000
PUBLIC SERVICE COMMISSION

June 16, 2000

Martin J. Huelsmann, Jr.
Executive Director
Public Service Commission of KY
211 Sower Blvd., P.O. Box 615
Frankfort, KY 40602-0615

OVERNIGHT COURIER

Re: The Integrated Resource Plan of Big Rivers Electric Corporation, P.S.C. Case No. 99-429

Dear Mr. Huelsmann:

Enclosed are an original and six (6) copies of the responses of Big Rivers Electric Corporation ("Big Rivers") to the information requests propounded by the Public Service Commission ("Commission") staff, the Attorney General and the Kentucky Division of Energy. Also enclosed is one (1) copy of sheets containing highlighted, confidential information that was redacted from the response of Big Rivers to Item 2 of the information requests of the Attorney General. The redacted information was previously granted confidential treatment in this matter by letter from the Commission dated May 10, 2000.

I certify that a copy of this letter and attachments, other than the confidential information, have been served by mail, postage prepaid, on each of the persons identified on the attached service list.

Sincerely yours,

James M. Miller

James M. Miller

Enclosures
cc: Mr. Michael Core
Mr. David Spainhoward

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

100 St. Ann Building
PO Box 727
Owensboro, Kentucky
42302-0727

SERVICE LIST
CASE NO. 99-429

Mr. John Stapleton
Department of Energy
663 Teton Trail
Frankfort, KY 40601

Ms. Iris Skidmore
Mr. Ronald P. Mills
Counsel for Natural Resources
And Environmental Protection
Office of Legal Services
Fifth Floor, Capital Plaza Tower
Frankfort, KY 40601

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

RECEIVED
JUN 1 9 2000
PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

The Integrated Resource Plan)
Of Big Rivers Electric Corporation) Case No. 99-429

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF
MAY 19, 2000

Items 1-19

June 19, 2000

1

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 1) Describe the progress Big Rivers has made in identifying industrial customers suited for the load management plan described on page 1-5 of the IRP.

Response) Big Rivers has worked with its members to determine the number of customers and the level of their participation for the coming summer. To date, 15 industrial customers have been identified based primarily on size of load. Most of the 15 customers have been sent a letter by their respective member cooperative offering them the opportunity to participate. A "Curtailable Service form" was enclosed with each letter. A generic sample of this form is attached. Big Rivers and its members chose to key on the larger customers first and work with the smaller customers later.

Witness) Bill Yeary

Curtailable Service Form

Month June

The only time that curtailment will be requested is between Hour Ending (H.E.) 0700 and H.E. 2200. It is further likely that the only hours that curtailment will be requested will be between H.E. 1300 and H.E. 1900 which are the hours of highest demand as well as highest market price.

Customer: Company XYZ **Kenergy Corp**

Demand Data:

Curtailable Demand

Maximum: ______ MW

Minimum: ______ MW

Time Data:

Maximum

Hours Per Day: ______ Hrs.

Number of Days: ______ Days

Consecutive Days: ______ Days

Price Data:

Minimum Price

Curtailable ($): ______ /MWH

Contact Persons at each Company:

Company XYZ

Name and Title	Phone Number	Fax Number

Kenergy Corp

Name and Title	Phone Number	Fax Number

Big Rivers Electric Corp

Name and Title	Phone Number	Fax Number

The parties to this agreement shall agree to the terms of the Voluntary Price Curtailable Service Rider. Executionof this agreement indicates the customers willingness to participate. When voluntary curtailment is requested ,the customer has the right, at that time, to accept or reject voluntary curtailment.

Curtailable Service Form

Month June

Signatures of Agreement:

Company XYZ

Name ______________________ Date ____________

Title ______________________

Kenergy Corp

Name ______________________ Date ____________

Title ______________________

Big Rivers Electric Corp.

Name ______________________ Date ____________

Title ______________________

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 2) Discuss how Big Rivers intends to encourage the use of distributed generation among its members, as was mentioned on page 1-16 of the IRP. Has Big Rivers or its member cooperatives performed any case-by-case analysis of the potential benefits of distributed generation additions, and if so, what were the results?

Response) Big Rivers will encourage the use of distributed generation by working in conjunction with its members to identify and assist the development of possible existing distributed generation on the members' system. In addition, Big Rivers will investigate the use of backup generation at hospitals and poultry processing operations to add to its mix of possible new supply side options.

Big Rivers has not performed any formal case-by-case analyses for distributed generation other that the 62 MW of distributed generation from one of the member's customers. The effects of the analysis of this generation are shown in Figure I-1 on page I-5 of the 1999 IRP. Other distributed generation would be expected to show similar results on a smaller scale.

In addition, nationally the electric cooperatives have formed a new organization called Energy Cooportunity which, among other areas, is involved with research and development of fuel cells for residential and commercial loads. Big Rivers is considering membership in this new cooperative so that it can monitor and review this research and further determine the role of fuel cells as a resource in its future.

Witness) Bill Yeary

3

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19, 2000

CASE NO. 99-429

Item 3) Pages IV-8 and 9 of the IRP discuss two voluntary curtailment programs, one by Florida Power and Light and one involving a "shared" savings approach during the period of interruption. Discuss Big Rivers' evaluations and any plans for both of these programs.

Response) Big Rivers successfully used a voluntary curtailment approach to share savings with some of its member customers during the summer of 1999. The Commission has recently approved a voluntary curtailment tariff for Big Rivers and its members in Case 2000-116. This utilizes the same concept as described on pages IV-8 and 9 of the IRP. An evaluation of Big Rivers' current situation indicates that this type of program will be utilized on at least a few occasions when demand is extraordinarily high and sales of firm capacity to other utilities are taking place. Curtailment programs exactly as discussed in the IRP have not been evaluated by Big Rivers at this time.

Witness) C. William Blackburn

4

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 4) According to Page IV-11 of the IRP, "In the best of all worlds, Big Rivers would eliminate residential participation for DSM programs and repackage programs as "Customer Satisfaction' options offered to the customers." Discuss Big Rivers' plans, and those of its member cooperatives, relative to residential DSM programs and whether there are any intentions to reduce or eliminate residential participation.

Response) Big Rivers' participation in residential demand side management programs involving direct cash incentives to install electric equipment has been eliminated. Information on energy efficiency for residential customers is promoted through direct customer contact and is soon to be available on various web sites sponsored by Big Rivers and its member cooperatives.

Witness) Russ Pogue

5

Item 5) For each recommendation made in the May 1995 PSC Staff Report on Big Rivers' 1993 IRP, discuss in detail and reference by section and page number how Big Rivers has addressed the recommendation in its latest IRP. For any recommendation that Big Rivers believes to be inapplicable because of subsequent events, so state and specifically explain why the recommendation is no longer applicable.

Response) __**Load Forecast**__

1. *Big Rivers could improve its forecast of electricity requirements by providing justification and additional support for the use of second methodology to forecast residential and small commercial sales to serve as a benchmark to the primary forecast methodology.* At page 2-10 of the Staff report, the Staff questioned the use of a second methodology since other utilities did not use a secondary methodology. As described at page II-18 of the Power Requirement Study that is attached as Appendix A to the IRP, Big Rivers compared the results of its primary forecast with the Energy Information Administration's "Annual Energy Outlook". This comparison shows that the Big Rivers projections are somewhat higher than national average projections. As indicated in the "Annual Energy Outlook", much of the projected growth in the national averages is due to increased electricity usage. The growth projected in the Big Rivers' system, when adjusted for the growth in consumers, is similar to the national average projections. Therefore, a secondary forecast was not performed.

2. *Big Rivers could improve its forecast of electricity requirements by reporting on efforts to incorporate DSM programs into the load forecast.* At page 2-9 of the Staff report, the recommendation was qualified that DSM should be incorporated if the DSM programs become larger and more established than currently. Since the programs have not become larger and more established and the current study indicates they would not be cost effective to Big Rivers or its members, Big Rivers felt it was not necessary to incorporate DSM programs into its load forecast. In addition, the process Big Rivers uses

to evaluate DSM programs is to consider them as another option to resource options. The load forecast is developed without any DSM aspects to place the evaluation of DSM or supply side options on an equal footing.

3. *Big Rivers could improve its forecast of electricity requirements by providing an intuitive as well as quantitative explanation of forecast results. Big Rivers has moved forward with respect to this recommendation but can continue to improve. Big Rivers should also provide further discussion of why it selects one source of data over another as inputs to its forecasting models.* Page II-5 through II-20 of the Power Requirements Study discuss the inputs and data that Big Rivers used in its load forecast. The data sources are further described in the Appendix to the Power Requirement Study. In addition, pages II-2 through II-5 of the IRP further discuss the forecast results. It is important to note that econometric modeling is a blend of quantitative and intuitive analysis. The use of econometric modeling to forecast sales is a highly quantitative process by its nature. A considerable amount of data is incorporated into the process. However, in order to develop a reasonable forecast, intuitive knowledge of the drivers of electricity sales must be understood. These drivers are then approximated using quantitative variables within the econometric process. In selecting data sources, it is important to review the various sources available, assess their historical accuracy and judge the reasonableness of the projections. This judgment is based on past experiences with various data sources and discussions with Big Rivers' staff members as well as the member cooperative staff members.

4. *Big Rivers could improve its forecast of electricity requirements by continuing to ensure that reasonable forecasts for natural gas are employed in the forecasting process.* Page III-3 of the IRP discusses the natural gas forecasts used in the analysis. The projections are based on the Energy Information Administration's energy price projections which are updated monthly to reflect changes in the market place. Because this is the source of the natural gas price projections employed in the modeling process,

the forecasts reflect the most recent information available at the time of the model development.

5. *Big Rivers could improve its forecast of electricity requirements by considering uncertainty in its ability to make off-system sales as part of the IRP process.* Big Rivers' business structure has changed substantially since the 1993 IRP. Off-system sales are no longer needed to allow Big Rivers to make its revenue requirements and are thus not considered as an energy requirement in the load forecast. The load forecast, since it is used to determine the demand and supply side programs most beneficial in meeting the requirements of the Big Rivers' native load system and not for off system customers, is based solely on the energy requirements of the Big Rivers' system and not the surrounding wholesale merchant market. The uncertainty of off system sales is a matter of incremental revenue as opposed to a resource need issue. Uncertainty of the incremental revenue, or attendant decrease in the cost of system purchases, is considered in the ranking of the alternatives.

6. *Big Rivers could improve its forecast of electricity requirements by reporting on changes to its forecasting methodology due to the DSM strategic study or other load forecast enhancements.* The response to recommendation 2 above explains how Big Rivers accounts for DSM in its planning process. The basic approach to the forecasting process used in the 1992 Power Requirements Study was enhanced as follows:

- The weather data used in the econometric modeling process was altered to more accurately reflect the weather for the Big Rivers member systems.
- Adjustments were made to the forecast to reflect rural and non-rural sales as well as to recognize the fact that two large accounts would no longer receive generation services from Big Rivers but would continue to receive transmission services.

- The forecast was prepared to represent the then-pending consolidation between Henderson-Union Electric Cooperative and Green River Electric Cooperative which occurred on July 1, 1999.

<u>Supply Side Resource Assessment</u>

1. *Big Rivers should continue to study the off-system power market utilizing the advice of expert consultants as appropriate and incorporate lessons from failed competitive bids.* Page III-3 of the IRP describes how the off-system sales market was considered. Burns & McDonnell is very active in the power supply market for new resources and provided information to Big Rivers during the development of its assumptions for the off-system market. In addition, Big Rivers is very active in the short-term market and is exposed daily to market intelligence and pricing information. The market has changed dramatically since the 1993 IRP and Big Rivers and Burns & McDonnell have invested considerable amounts of time working with these changes.

2. *Big Rivers should consider uncertainty in the level of off-system sales in its planning process.* Pages VI-1 through VI-6 of the IRP discuss the uncertainty analysis performed regarding variability in the level of off-system sales. Big Rivers' business structure has changed substantially since the 1993 IRP. Off-system sales are no longer needed to allow Big Rivers to make its revenue requirements. The uncertainty of off-system sales is a matter of incremental revenue as opposed to a resource need issue. Uncertainty of the incremental revenue, or attendant decrease in the cost of system purchases, is considered in the ranking of the alternatives.

The uncertainty in off-system sales was evaluated in a number of future scenarios for Big Rivers. A 20% reduction in spot market sales was made starting in 2001 due to the addition of merchant plants in the region. The reason for the uncertainty analysis was to determine if the ranking of the alternatives was affected by a reduction in sales revenue and a reduction in the cost of purchases as well, not to determine the likely financial impact to Big Rivers. The reduction had no affect on the ranking of the alternatives.

The off-system market that Big Rivers is operating within is changing its pricing dramatically. The high prices seen in the peak summer season and moving into a broader shoulder around this peak are uncoupled from the production cost of the machines. As the wholesale market moves to an energy only pricing scheme, the high prices seen in the summers of 1998 and 1999 will be required for the merchants to recover the cost of peaking and intermediate plants installed. With this movement to an energy only pricing scheme, the merchant plants are forced to recover the fixed and variable costs through the energy price. With the majority of the new merchant plants being gas based and the current high price of gas, the energy price is approaching $32/MWh for just the energy component of the cost for the most efficient plants. Since the merchants also have to recover a portion of their fixed cost in the energy price, they have significant reason to maintain a high price for electricity. Big Rivers, however, is able to sell electricity at a cost based on the LEM contract, which is substantially below the merchant marginal energy cost. Therefore, Big Rivers is in a position to be below the cost of the merchant market and should be able to obtain sales of its excess prior to merchant plant sales. This indicates that the uncertainty of Big Rivers being able to sell off-system is very low. However, the price for which it can sell and hence its margins will be based on the supply/demand conditions of the market at the time.

3. *Big Rivers should continue to study transmission upgrades that will improve its ability to make off-system sales and report back on these studies in subsequent plans.* Pages II-7 through II-8 of the IRP discuss Big Rivers' transmission. Big Rivers is active in the transmission planning process through its ECAR participation. There are no current major transmission projects underway that would provide increased access to the off-system sales market. This is due primarily to the transition of the transmission industry as a result of FERC Orders 888 and 2000. ISO information is moving forward

and it is unlikely that any major transmission projects will be implemented until this transition is complete. Big Rivers continues to participate in this transition and will incorporate any projects announced in its subsequent IRP filings. Also please refer to Big Rivers response to Kentucky Division of Energy's First Request for information Item No. 21.

Demand-Side Management

1. *Big Rivers should provide analysis to support DSM load shape objectives. In particular, it should clarify its support for the objective of load shifting.*

Page IV-3 of the IRP describes viable DSM options for Big Rivers and the objectives it plans to accomplish. In addition, the load duration curves included in Appendix X of the IRP indicates the following:

a) Surplus capacity is available at least 96% of the time during the first five years of this study.

b) Capacity factors for the Big Rivers system remain near 60% (+/-1%) throughout the entire 15 years studied.

c) During several years studied (see the last column), Big Rivers is committed to contractual capacity purchases that it does not use. (see 2001 through 2009 and again starting in 2012).

The table which follows indicates that Big Rivers will benefit most from reducing demand and increasing its energy sales. In this way, the load factor will improve and purchases (to meet excess demand) will be minimized or mitigated. Given the take-or-pay nature of contracts that are in place, other DSM options, namely, strategic conservation, will have a negative impact on Big Rivers' financial situation.

(See Table below)

Year	Cap Def. (MW)	Energy Def (MWh)	Hours Def (hours)	% of Year	Load Factor	Cap. Exc. (min. Purchase)
1998	71	5,859	83	1%	59.80%	marginal
1999	111	20,409	184	2%	61.60%	No
2000	145	41,773	288	4%	62.30%	No
2001	73	5,707	78	1%	62.20%	Yes
2002	92	9,552	104	1%	62.20%	Yes
2003	108	14,918	138	2%	61.90%	Yes
2004	123	21,129	172	2%	61.70%	Yes
2005	138	29,146	211	3%	61.50%	Yes
2006	155	39,617	256	3%	61.40%	Yes
2007	168	49,009	292	4%	61.20%	Yes
2008	184	62,231	338	4%	61.00%	Marginal
2009	203	81,154	400	5%	60.90%	Marginal
2010	234	116,389	497	6%	61.60%	No
2011	131	18,723	143	2%	61.40%	No
2012	65	1,958	30	0%	61.20%	yes
2013	87	4,911	56	1%	61.30%	Yes

2. *Big Rivers should use its consultant study to formulate a research program and action plan for DSM evaluation and implementation.* Pages IV-3 through IV-5 describe the general conclusions of the R. W. Beck study and how those results were incorporated into

the IRP study. The R. W. Beck study has been provided in response to the Division of Energy's First Information Request Item No.12.

In addition, Big Rivers will continue to evaluate new DSM options as these emerge. General trends indicate that traditional DSM (other than load shifting) will become less cost effective with time. This is primarily due to the advent of commodity energy and capacity sales, reduced costs for supply-side options, and marked efficiency improvements in appliances, motors and chillers.

3. Big Rivers should continue to improve its screening methodology including:

- Expanding the analysis to include additional programs as anticipated in the consultant study.
- Developing better sources of data.
- Providing analysis and discussion of DSM selection criteria.
- Developing a clear format for presenting DSM program data and assumptions, possibly utilizing the example provided in this section.

The screening methodology is thoroughly discussed in the R. W. Beck study at pages 3-1 through 3-5.

4. *Big Rivers should use an alternative method to develop the societal test measure.* The Total Resource Cost test is used as a proxy for the societal test in the R. W. Beck study. Most utilities in the United States have applied a similar methodology in evaluating their DSM programs. The Total Resource Cost Test incorporates all of the components in the more traditional societal test. In addition, the Total Resource Cost test allows for a broader use of externalities, their benefits and costs in evaluating DSM programs.

Use of the TRC and its application to this study can be found on pages 2-6 and 3-1 through 3-9 of the R. W Beck study.

5. *Big Rivers should provide a detailed and thorough analysis of all of its existing programs. This review should state why Big Rivers is supporting programs that fail economic cost-benefit tests.* Big Rivers has no existing DSM programs in its resource mix. Proposed programs, including that established by Rate Schedule 11 and two proposed residential programs (which are marginally cost-effective) are detailed in section IV of the IRP filed with the Kentucky Public Service Commission in 1999.

Acid Rain Plan And Option Integration

The 1995 PSC Staff Report at pages 5-11 and 5-12 included 5 recommendations regarding Big Rivers' acid rain plan. However, with the implementation of the Big Rivers/LG&E Energy transaction, Big Rivers no longer administers the acid rain compliance. Consequently, issues associated with the generation units studied in the 1993 IRP and the recommendations provided by the PSC Staff in this area are no longer applicable.

Witness) Armando de Leon
Burns & McDonnell

6

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19, 2000

CASE NO. 99-429

Item 6) Explain whether the recently proposed purchase of LG&E Energy Corporation by PowerGen plc will change any of the plans discussed in the IRP.

Response) Big Rivers is monitoring the proposed purchase of LG&E Energy Corporation by PowerGen plc very closely. Based upon the information LG&E Energy Corp. and PowerGen plc have provided, Big Rivers does not anticipate that the proposed purchase will change any of the plans discussed in the IRP.

Witness) David A. Spainhoward

Item 7) One of the IRP's recommendations is that Big Rivers maintain an ongoing dialogue with other potential power suppliers regarding low cost energy and capacity sources. Are there any new developments in that regard relative to power requirements for the 2004 to 2011 time frame?

Response) Big Rivers continues its ongoing dialogue with potential power suppliers regarding low cost energy and capacity resources with companies like Duke, Williams, Western Kentucky Energy, and Reliant. Big Rivers is presently having very preliminary discussions about an arrangement for a capacity supplier to add additional capacity for summer peak conditions only. This added capacity could significantly affect Big Rivers capacity outlook from 2004 through 2011.

Witness) C. William Blackburn

8

Item 8) Are there any significant effects from the merger that resulted in Kenergy Corp. and a rate reduction that could impact the conclusions or results of the 1999 IRP?

Response) There are no significant effects that could impact the conclusions or results of the 1999 IRP.

Witness) Bill Yeary

9

CASE NO. 99-429

Item 9) Discuss any significant effects anticipated from tariffs filed by Big Rivers since the Power Requirements Study was finalized in September 1999, and how those effects could impact the conclusions or results of the 1999 IRP.

Response) Since the Power Requirements Study (PRS) was filed in September 1999, the Kentucky Public Service Commission has approved two new tariffs. Rate Schedule 10 gives Big Rivers added stability for its capacity planning by alleviating the possibility of one industrial customer taking the remainder of Big Rivers' capacity. This schedule also allows industrial customers the benefit of receiving as much capacity as needed from its distribution cooperative, provided at wholesale by Big Rivers at market or negotiated prices. Over the planning period of the PRS, Rate Schedule 10 reduces the risk of Big Rivers being required to supply wholesale power to its members to serve large industrial load increases from Big Rivers' present resources. Rate Schedule 11 allows Big Rivers to work with its members and their customers to curtail load during times of high peak demand. This reduces demand from the customer and thereby reduces Big Rivers' native peak demand as shown in the PRS. These tariffs along with the 62 MW of cogeneration could eliminate the need for additional capacity through the study horizon.

Witness) C. William Blackburn

CASE NO. 99-429

Item 10) Reference is made to Rate Schedule 10 on page 1-2 of the IRP. Is any load presently being served on Rate Schedule 10? Are any new load additions expected to be served on Rate Schedule 10 by the end of calendar year 2000? If yes to either question, provide the size of the loads.

Response) No load is presently being served on Rate Schedule 10. Big Rivers is not presently aware of any new load additions expected to be served on Rate Schedule 10 by the end of calendar year 2000.

Witness) Bill Yeary

Item 11) If 62 MW of generation by a Kenergy customer does not occur as anticipated, Big Rivers is expected to become capacity deficient by 2004.

a. Given the current status of the market for combustion turbines, will Big Rivers be able to install new capacity before 2004?

b. If by September 1, 2000, Big Rivers determines that the 62 MW of generation is not going to be installed, identify the specific actions that will be required, and the timeline for these actions, to ensure that additional capacity is installed by 2004.

Response) a. Yes. Big Rivers should have time to acquire and install new capacity before 2004 if it chooses this method to cover its capacity deficiency.

b. By early 2001, Big Rivers will know:

1) The degree of interest that industrial customers have in voluntary curtailment.
2) Whether the reports of the peaking capacity additions becomes reality.

From the degree of interest that Big Rivers experienced last summer and the interest that has been expressed this year in the Voluntary Price Curtailable Service Rider approved in Case No. 2000-116, Big Rivers should be able to reduce demand and have sufficient capacity beyond the year 2004. A better determination can be made by early 2001.

If the announced peaking capacity additions by others become a reality, it will not make sense for Big Rivers to add generation capacity also. According to general market opinion, peaking capacity prices will fall as more peaking units are installed. If Big Rivers' peak demand can be reduced by Big Rivers' member customers taking advantage of Rate Schedule 11, the need for additional capacity can be pushed out beyond 2004. Market purchase of the small amount of Big Rivers' additional needed capacity would be best. Big Rivers will benefit from waiting as long as possible to secure the additional needed resources.

Big Rivers will also be considering and evaluating other tariff and rate options which would further reduce capacity demand.

Big Rivers intends to maintain as much flexibility as possible in planning for its supply of capacity to its members.

Witness) C. William Blackburn

12

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 12) Refer to page 1-14 of the IRP. Provide a brief description of the types of changes to SEPA that have been the subject of congressional discussions.

Response) On June 24, 1999 an Oversight Hearing on The Role of Power Marketing Administrations (PMA) in a Restructured Electric Industry, testimony was given before the U.S. House of Representatives Committee on Resources Subcommittee on Water and Power. Some of the testimony questioned the very basis for the existence of PMA's.

The NRECA has asked its members to ask members of Congress to:

Oppose efforts to privatize the PMA's.

Oppose changes in the rate structure of PMA's.

Restore approximately $60 million in appropriations for the PMA'a power purchasing and wheeling requirements.

Witness) Bill Yeary

13

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19, 2000

CASE NO. 99-429

Item 13) Refer to page 11-5 of the IRP. Provide the specific expiration dates for each of Big Rivers' three existing wholesale power sales contracts.

Response) The expiration dates for the Hoosier, Oglethorpe and HMP&L contracts are:

Hoosier - December 31, 2000
Oglethorpe - July 31, 2002
HMP&L - May 31, 2000

Witness) David A. Spainhoward

14

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 14) Refer to page III-5 of the IRP under "Unit Purchases" which discusses the planned merchant plant activity in or near Big Rivers' service territory. Provide updates to any of this information to reflect events that have occurred since the IRP was prepared.

Response) The five units mentioned in the IRP are still proposed. Additionally, Duke Energy is planning to build a 640 MW natural gas-fired plant near Calvert City, KY to be online in 2001. Cogentrix is planning to build a 500 MW gas-fired plant near Bedford, IN to be online in 2002. LS Power LLC is planning to build an 800 MW gas-fired plant near Columbus, IN to be online in 2002.

Witness) Armando de Leon
Burns & McDonnell

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 15) Refer to page IV-12 of the IRP regarding Burns & McDonnell's DSM recommendations to Big Rivers. To date, identify any actions Big Rivers has taken in response to those recommendations.

Response) Big Rivers has sought and obtained approval from the Kentucky Public Service Commission for Rate Schedule 10, (Big Rivers Large Industrial Customer Expansion Rate Tariff) which is available to any of Big Rivers' member cooperatives for service to certain large industrial or commercial loads in their service territory. There are no industrial additions taking service under this tariff at the present time.

Big Rivers is working with its members to utilize the voluntary curtailment tariff. Also, please see Big Rivers' response to the Commission Staff's request for information Item No. 1.

Witness) Bill Yeary

16

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 16) Refer to Part VII of the IRP titled "Conclusion and Three Year Plan." Explain the significance of three years. Identify if this is related to Big Rivers' cycle for preparing its Power Requirements Study ("PRS").

Response) The three-year plan is included to fit the 33 month filing schedule Big Rivers is required to follow according to 807 KAR 5:058, Section 2. (a) 5. This is not related to Big Rivers' PRS schedule, as the PRS is prepared every 2 years.

Witness) Armando de Leon
Burns & McDonnell

17

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 17) In its 1999 PRS, Big Rivers identifies Woods and Poole Economics, Inc. as one of its data sources. Other utilities regulated by the Commission have recently begun using this same firm. Provide the date when Big Rivers began using this firm in conjunction with the development of its PRS.

Response) Big Rivers started using Woods and Poole Economics, Inc. as one of its data sources for the 1989 PRS.

Witness) Bill Yeary

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 18) Page 1-4 of the IRP indicates that "the LEM contract includes liquidated damages for non-delivery." Discuss how the damages that would be payable under the contract if LEM fails to deliver the required power would be calculated. Should the non-performance occur in a period of escalating prices, such as that experienced during the summers of 1998 and 1999, explain whether the damages would include some portion of the premium that Big Rivers might have to pay for power at market prices and how that portion would be determined.

Response) The Power Purchase Agreement (PPA) with LEM states, "In each of the preceding circumstances in which damages are due, such damages shall equal the damaged party's reasonably incurred replacement power costs (including costs of any related Ancillary Services)." If LEM fails to deliver the required power, Big Rivers would then have its marketer supply the power at market prices. All costs associated with Big Rivers replacing the power (including the related Ancillary Services) would then be invoiced to LEM.

If non-performance occurs during high prices (as in the summers of 1998 and 1999), all costs that Big Rivers would have to pay at market prices to replace the undelivered LEM power would be invoiced to LEM.

Witness) C. William Blackburn

19

Reorder No. 5109
JULIUS BLUMBERG, INC.
NYC 10013
®10% P.C.W.

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 19) Page 1-7 of the IRP refers to the recommendation that Big Rivers should study the implementation of a combined commercial and industrial DSM plan and that approval of Rate Schedule 10 is a solid first step in the implementation of the plan. Explain how Rate Schedule 10 aids in implementing the DSM plan.

Response) The reference to Rate Schedule 10 in the IRP submitted by Big Rivers is a typographical error. The paragraph should refer to rate Schedule 11, the curtailable tariff proposed by Big Rivers and approved by the Kentucky Public Service Commission for implementation.

Witness) Armando de Leon
Burns & McDonnell

19

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE COMMISSION STAFF'S
REQUEST FOR INFORMATION OF MAY 19,2000

CASE NO. 99-429

Item 19) Page 1-7 of the IRP refers to the recommendation that Big Rivers should study the implementation of a combined commercial and industrial DSM plan and that approval of Rate Schedule 10 is a solid first step in the implementation of the plan. Explain how Rate Schedule 10 aids in implementing the DSM plan.

Response) The reference to Rate Schedule 10 in the IRP submitted by Big Rivers is a typographical error. The paragraph should refer to rate Schedule 11, the curtailable tariff proposed by Big Rivers and approved by the Kentucky Public Service Commission for implementation.

Witness) Armando de Leon
Burns & McDonnell

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

The Integrated Resource Plan)
of Big Rivers Electric Corporation)

Case No. 99-429

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL OF THE COMMONWEALTH OF KENTUCKY
INITIAL REQUEST FOR INFORMATION OF MAY 18, 2000

Items 1-9

June 19, 2000

1

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL OF THE
COMMONWEALTH OF KENTUCKY
INITIAL REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 1) The IRP mentions the addition of 62 MW of distributive generation on the Kenergy system. With respect to this addition please provide the following information:

a) The name of the customer that is adding the capacity;
b) The type of generator;
c) The fuel type and source;
d) The expected availability of this unit.
e) Will this be operated in a co-generation mode?
f) Will Kenergy be expected to supply back-up capacity when this unit is down?
g) Will planned outages of this unit be scheduled with Big Rivers and Kenergy?

Response)
a) Willamette Industries, Inc.
b) Steam turbine generator
c) Organic by-products from the Willamette's paper industry, comprised of lignin, spend chemicals, waste wood, saw dust, and minimal natural gas.
d) 97%
e) Yes
f) Yes, through Big Rivers as wholesale supplier.
g) Yes

Witness) Bill Yeary

Item 2) On page I-9 of the IRP, reference is made to significant revenues be generated from sales of surplus energy received from the LEM contract. With respect to these sales:

a) Please supply the projected annual kWh sales and margins that were projected as a part of the workout plan, proposed and accepted by the Commission in Case No. 97-204.

b) Please supply the actual annual kWh sales and margins received by Big Rivers since the LEM contract has been in place and surplus energy has been sold off-system.

c) Please supply the projected annual kWh sales and margins that are included in the optimal IRP plan (case 5), and please explain any difference between these figures and those contained in the workout plan in Case No. 97-204.

Response) a) The attached schedule (page 3 of 4) provides the requested information for years 2011 through 2022. There were no arbitrage or other sales included in the workout for years prior to 2011.

b)

		MWh	Revenue	Margin[1]
	1998	190,588	$ 8,043,585	
	1999	528,918	19,653,130	REDACTED
Jan-April	2000	171,896	4,458,879	

[1]The redacted information is a compilation of information for which confidential treatment was granted in this case on May 10, 2000.

c) The attached schedule (page 4 of 4) contains the projected annual MWh sales and margins that were included in the IRP plan case (5).

The major differences between the IRP case (5) and the workout plan are as follows:

a. Taking a conservative approach, Big Rivers did not forecast any arbitrage or other sales in its workout plan prior to 2011.

b. The major differences for the years 2011, 2012, and 2013 are as follows:

1. A higher native load forecast was used in the IRP and consequently less surplus energy is available for off system sales.
2. The IRP case (5) shows all excess energy being sold versus approximately 47 percent of the excess energy being sold in the workout plan.
3. Gross revenue was driven by using the 1998 and 1999 spot market prices for the IRP study versus a more conservative approach being used n the workout plan. The gross revenue reflected in the IRP is very aggressive and dependent upon the projected spot market prices for electricity continuing to have summer peak prices similar to those experienced during the prior two summers.
4. A transmission loss factor of 1.56 percent was used in the IRP versus 2 percent in the workout plan.

[1]The redacted information is a compilation of information for which confidential treatment was granted in this case on May 10, 2000.

Witness) Mark Hite, C. William Blackburn
Armando de Leon
Burns & McDonnell

Case No. 97-204 - SURPLUS ENERGY - mWh SALES AND MARGINS (In Thousands of $)

RESPONSE to ATTORNEY GENERAL QUESTION 2.a.

	2011	2012	2013	2014	2015	2016
Sales of Surplus Energy (Arbitrage/Other Sales) - mWh	1,220,819	1,535,586	1,493,019	1,449,089	1,403,754	1,356,964
Rate (Including Big Rivers Transmission Rate)	29.832	30.272	30.727	31.181	31.649	32.118
Gross Revenue	36,419	46,485	45,876	45,184	44,427	43,583
LEM Power Cost	26,084	31,744	31,352	30,917	30,422	29,879
Big Rivers Transmission Cost	3,737	4,701	4,570	4,436	4,297	4,154
Net Revenue	6,598	10,040	9,954	9,831	9,708	9,550
Gross Revenue - mWh	29.832	30.272	30.727	31.181	31.649	32.118
Power Cost - mWh	21.366	20.672	20.999	21.335	21.672	22.019
Transmission Cost - mWh	3.061	3.061	3.061	3.061	3.061	3.061
Margin - mWh	5.405	6.538	6.667	6.784	6.916	7.038

	2017	2018	2019	2020	2021	2022
Sales of Surplus Energy (Arbitrage/Other Sales) - mWh	1,308,673	1,258,833	1,207,392	1,154,293	1,099,491	1,042,957
Rate (Including Big Rivers Transmission Rate)	32.599	33.081	33.577	34.087	34.582	35.085
Gross Revenue	42,661	41,643	40,541	39,346	38,023	36,592
LEM Power Cost	29,269	28,604	27,866	27,064	26,194	25,231
Big Rivers Transmission Cost	4,006	3,854	3,696	3,534	3,366	3,193
Net Revenue	9,386	9,185	8,979	8,748	8,463	8,168
Gross Revenue - mWh	32.599	33.081	33.577	34.087	34.582	35.085
Power Cost - mWh	22.365	22.723	23.079	23.446	23.824	24.192
Transmission Cost - mWh	3.061	3.062	3.061	3.062	3.061	3.061
Margin - mWh	7.172	7.296	7.437	7.579	7.697	7.832

Response to Attorney General Question 2.c. [1]

Projected Annual kWh Sales and Margins

	2000	2001	2002	2003	2004	2005	2006
Sales of Surplus Energy (Arbitrage/Other Sales) (MWh)	475,961	661,173	736,953	763,386	764,616	730,169	692,089
Rate (Including Big Rivers Transmission Rate) ($/MWh)							
Gross Revenue ($)				REDACTED			
LEM Power Cost							
Big Rivers Transmission Cost	1,367	1,899	2,116	2,192	2,196	2,097	1,987
Net Revenue							
Gross Revenue ($/MWh)				REDACTED			
Power Cost ($/MWh)							
Transmission Cost ($/MWh)	2.872	2.872	2.872	2.872	2.872	2.872	2.872
Margin ($/MWh)							
				REDACTED			

	2007	2008	2009	2010	2011	2012	2013
Sales of Surplus Energy (Arbitrage/Other Sales) (MWh)	656,103	612,855	554,029	460,798	927,857	1,222,121	1,158,703
Rate (Including Big Rivers Transmission Rate) ($/MWh)							
Gross Revenue ($)							
LEM Power Cost				REDACTED			
Big Rivers Transmission Cost	1,884	1,760	1,591	1,323	2,665	3,510	3,327
Net Revenue							
Gross Revenue ($/MWh)				REDACTED			
Power Cost ($/MWh)							
Transmission Cost ($/MWh)	2.872	2.872	2.872	2.872	2.872	2.872	2.872
Margin ($/MWh)				REDACTED			

3

Item 3) On page I-14 of the IRP, reference is made to projected load growth contained in the IRP. With respect to projected load growth:

a) Please supply the actual peak loads and energy sales for the Big Rivers system, excluding the smelter loads, for each of the last 15 years.

b) Please provide the projected load growth, in both peak loads and energy sales, contained in the workout plan, proposed and accepted by the Commission in Case No. 97-204, and provide an explanation of why the projected growth figures in the IRP differ from those in the workout plan.

Response) a) Please see the attached schedules for the period 1985 through 1999, which contains member peak demand MW, billing demand kW and billing energy MWh, excluding the two aluminum smelter loads. For comparability, billing demand kW for periods prior to 1998 is shown exclusive of the demand ratchet then in effect and minimum contract demand. The breakdown of the historical peak demand MW between Rural and Large Industrial is not available. (The chosen format of this response is to provide an "apples-to-apples" comparison to (b) below.)

b) Please see the attached schedules for the period 2000 through 2023, which contains member peak demand MW, billing demand kW and billing energy MWh, excluding the two aluminum smelters, from both the 1999 Power Requirements Study (PRS) and the 1997 PRS – Adjusted. Note that the projected non-smelter member load per Case No. 97-204 is that included in the financial model referred to as PSC2-38R, and the basis of such load therein has been previously described as 1997 PRS – Adjusted.

The Large Industrial load difference is due to greater loads forecasted by both Willamette and Kimberly-Clark in the 1999 PRS. The Rural average annual compound load growth over the 23-year period contained in both the 1999 PRS and the 1997 PRS – Adjusted is approximately 2.6%, however the benchmark is higher for the 1999 PRS due to greater than anticipated historical load growth.

Witness) Mark A. Hite and Bill Yeary

	1985	1986	1987	1988	1989	1990	1991	1992
Peak Demand MW	408	439	444	486	459	485	492	472
Billing Demand kW								
Rural	3,013,122	3,077,509	3,143,243	3,300,257	3,453,096	3,313,631	3,342,483	3,203,028
Large Industrial	1,324,984	1,384,346	1,411,484	1,415,249	1,467,785	1,617,736	1,598,074	1,605,042
	4,338,106	4,461,855	4,554,727	4,715,506	4,920,881	4,931,367	4,940,557	4,808,070
Billing Energy MWh								
Rural	1,376,988	1,429,975	1,356,940	1,410,322	1,430,106	1,402,589	1,488,537	1,438,257
Large Industrial	566,783	583,061	744,150	754,636	757,779	845,867	831,043	860,119
	1,943,771	2,013,036	2,101,090	2,164,958	2,187,885	2,248,456	2,319,580	2,298,376

	1993	1994	1995	1996	1997	1998	1999
Peak Demand MW	524	491	575	580	596	643	664
Billing Demand kW							
Rural	3,455,094	3,514,263	3,636,413	3,944,110	3,871,232	4,121,747	4,184,721
Large Industrial	1,595,875	1,660,197	1,842,712	1,970,957	2,207,090	2,490,868	2,601,031
	5,050,969	5,174,460	5,479,125	5,915,067	6,078,322	6,612,615	6,785,752
Billing Energy MWh							
Rural	1,580,303	1,571,690	1,665,311	1,728,687	1,758,397	1,861,052	1,921,742
Large Industrial	868,969	907,640	1,019,129	1,092,610	1,258,706	1,427,792	1,547,230
	2,449,272	2,479,330	2,684,440	2,821,297	3,017,103	3,288,844	3,468,972

	2000	2001	2002	2003	2004	2005	2006	2007
1999 PRS								
Peak Demand MW								
Rural	475	490	504	520	534	550	566	579
Large Industrial	242	245	247	247	247	247	248	248
	717	735	751	767	781	797	814	827
Billing Demand kW								
Rural	4,632,427	4,772,582	4,909,320	5,065,915	5,206,026	5,359,498	5,515,999	5,644,282
Large Industrial	2,906,736	2,942,736	2,966,736	2,966,736	2,969,136	2,969,136	2,981,136	2,981,136
	7,539,163	7,715,318	7,876,056	8,032,651	8,175,162	8,328,634	8,497,135	8,625,418
Billing Energy mWh								
Rural	2,063,513	2,130,875	2,194,118	2,267,802	2,329,407	2,396,862	2,465,741	2,522,207
Large Industrial	1,679,224	1,702,283	1,722,283	1,722,283	1,724,503	1,724,503	1,732,562	1,732,562
	3,742,737	3,833,158	3,916,401	3,990,085	4,053,910	4,121,365	4,198,303	4,254,769
1997 PRS - Adjusted (PSC2-38R)								
Peak Demand MW								
Rural	465	487	499	510	523	535	548	560
Large Industrial	216	217	215	215	215	215	215	215
	681	704	714	725	738	750	763	775
Billing Demand kW								
Rural	4,459,657	4,626,408	4,752,212	4,881,257	5,015,149	5,153,202	5,295,586	5,434,494
Large Industrial	2,654,900	2,686,400	2,660,000	2,660,000	2,660,000	2,660,000	2,660,000	2,660,000
	7,114,557	7,312,808	7,412,212	7,541,257	7,675,149	7,813,202	7,955,586	8,094,494
Billing Energy mWh								
Rural	1,960,474	2,011,777	2,066,587	2,122,829	2,181,162	2,241,316	2,303,365	2,363,916
Large Industrial	1,555,607	1,560,261	1,550,061	1,550,061	1,550,061	1,550,061	1,550,061	1,550,061
	3,516,081	3,572,038	3,616,648	3,672,890	3,731,223	3,791,377	3,853,426	3,913,977
Difference								
Peak Demand MW								
Rural	10	3	5	10	11	15	18	19
Large Industrial	26	28	32	32	32	32	33	33
	36	31	37	42	43	47	51	52
Billing Demand kW								
Rural	172,770	146,174	157,108	184,658	190,877	206,296	220,413	209,788
Large Industrial	251,836	256,336	306,736	306,736	309,136	309,136	321,136	321,136
	424,606	402,510	463,844	491,394	500,013	515,432	541,549	530,924
Billing Energy mWh								
Rural	103,039	119,098	127,531	144,973	148,245	155,546	162,376	158,291
Large Industrial	123,617	142,022	172,222	172,222	174,442	174,442	182,501	182,501
	226,656	261,120	299,753	317,195	322,687	329,988	344,877	340,792

	2008	2009	2010	2011	2012	2013	2014	2015
1999 PRS								
Peak Demand MW								
Rural	594	612	628	644	661	678	694	713
Large Industrial	248	250	265	265	265	271	274	272
	842	862	893	909	926	949	968	985
Billing Demand kW								
Rural	5,800,015	5,973,392	6,129,569	6,291,413	6,459,034	6,624,999	6,786,269	6,966,024
Large Industrial	2,981,136	3,005,136	3,185,136	3,185,136	3,185,136	3,257,136	3,257,136	3,259,536
	8,781,151	8,978,528	9,314,705	9,476,549	9,644,170	9,882,135	10,043,405	10,225,560
Billing Energy mWh								
Rural	2,590,681	2,666,968	2,735,642	2,806,880	2,880,786	2,953,839	3,024,871	3,104,065
Large Industrial	1,732,562	1,748,681	1,869,569	1,869,569	1,869,569	1,917,924	1,917,924	1,919,560
	4,323,243	4,415,649	4,605,211	4,676,449	4,750,355	4,871,763	4,942,795	5,023,625
1997 PRS - Adjusted (PSC2-38R)								
Peak Demand MW								
Rural	573	587	600	614	628	643	657	672
Large Industrial	230	230	230	230	230	241	241	241
	803	817	830	844	858	884	898	913
Billing Demand kW								
Rural	5,577,252	5,724,033	5,874,990	6,030,312	6,184,098	6,341,454	6,502,792	6,668,344
Large Industrial	2,840,000	2,840,000	2,840,000	2,840,000	2,840,000	2,972,000	2,972,000	2,972,000
	8,417,252	8,564,033	8,714,990	8,870,312	9,024,098	9,313,454	9,474,792	9,640,344
Billing Energy mWh								
Rural	2,426,143	2,490,129	2,555,948	2,623,670	2,690,744	2,759,381	2,829,758	2,901,984
Large Industrial	1,661,751	1,661,751	1,661,751	1,661,751	1,661,751	1,743,657	1,743,657	1,743,657
	4,087,894	4,151,880	4,217,699	4,285,421	4,352,495	4,503,038	4,573,415	4,645,641
Difference								
Peak Demand MW								
Rural	21	25	28	30	33	35	37	41
Large Industrial	18	20	35	35	35	30	33	31
	39	45	63	65	68	65	70	72
Billing Demand kW								
Rural	222,763	249,359	254,579	261,101	274,936	283,545	283,477	297,680
Large Industrial	141,136	165,136	345,136	345,136	345,136	285,136	285,136	287,536
	363,899	414,495	599,715	606,237	620,072	568,681	568,613	585,216
Billing Energy mWh								
Rural	164,538	176,839	179,694	183,210	190,042	194,458	195,113	202,081
Large Industrial	70,811	86,930	207,818	207,818	207,818	174,267	174,267	175,903
	235,349	263,769	387,512	391,028	397,860	368,725	369,380	377,984

	2016	2017	2018	2019	2020	2021	2022	2023
1999 PRS								
Peak Demand MW								
Rural	729	747	765	784	803	822	842	862
Large Industrial	272	272	278	278	278	278	278	278
	1,001	1,019	1,043	1,062	1,081	1,100	1,120	1,140
Billing Demand kW								
Rural	7,130,378	7,304,340	7,481,060	7,662,141	7,847,692	8,037,833	8,232,675	8,432,331
Large Industrial	3,259,536	3,259,536	3,331,536	3,331,536	3,331,536	3,331,536	3,331,536	3,331,536
	10,389,914	10,563,876	10,812,596	10,993,677	11,179,228	11,369,369	11,564,211	11,763,867
Billing Energy mWh								
Rural	3,176,454	3,253,030	3,330,917	3,410,711	3,492,460	3,576,214	3,662,023	3,749,939
Large Industrial	1,919,560	1,919,560	1,967,915	1,967,915	1,967,915	1,967,915	1,967,915	1,967,915
	5,096,014	5,172,590	5,298,832	5,378,626	5,460,375	5,544,129	5,629,938	5,717,854
1997 PRS - Adjusted (PSC2-38R)								
Peak Demand MW								
Rural	689	707	725	744	763	783	803	824
Large Industrial	241	241	241	241	241	241	241	241
	930	948	966	985	1,004	1,024	1,044	1,065
Billing Demand kW								
Rural	6,838,299	7,012,728	7,191,763	7,375,517	7,564,129	7,757,719	7,956,780	8,160,949
Large Industrial	2,972,000	2,972,000	2,972,000	2,972,000	2,972,000	2,972,000	2,972,000	2,972,000
	9,810,299	9,984,728	10,163,763	10,347,517	10,536,129	10,729,719	10,928,780	11,132,949
Billing Energy mWh								
Rural	2,976,143	3,052,261	3,130,390	3,210,585	3,292,901	3,377,396	3,464,059	3,552,946
Large Industrial	1,743,657	1,743,657	1,743,657	1,743,657	1,743,657	1,743,657	1,743,657	1,743,657
	4,719,800	4,795,918	4,874,047	4,954,242	5,036,558	5,121,053	5,207,716	5,296,603
Difference								
Peak Demand MW								
Rural	40	40	40	40	40	39	39	38
Large Industrial	31	31	37	37	37	37	37	37
	71	71	77	77	77	76	76	75
Billing Demand kW								
Rural	292,079	291,612	289,297	286,624	283,563	280,114	275,895	271,382
Large Industrial	287,536	287,536	359,536	359,536	359,536	359,536	359,536	359,536
	579,615	579,148	648,833	646,160	643,099	639,650	635,431	630,918
Billing Energy mWh								
Rural	200,311	200,769	200,527	200,126	199,559	198,818	197,964	196,993
Large Industrial	175,903	175,903	224,258	224,258	224,258	224,258	224,258	224,258
	376,214	376,672	424,785	424,384	423,817	423,076	422,222	421,251

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL OF THE
COMMONWEALTH OF KENTUCKY
INITIAL REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 4) Please provide a detailed explanation of Big Rivers' and its three Cooperative's efforts, both current and proposed, to encourage distributive generation.

Response) Please refer to Big Rivers' response to the Commission Staff's Initial Data Request Item 2.

Witness) Bill Yeary

5

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL OF THE
COMMONWEALTH OF KENTUCKY
INITIAL REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 5) Please provide any written policy statement Big Rivers has adopted to encourage the distributive generation.

Response) Big Rivers has no written policy statement which expressly encourages distributive generation.

Witness) Bill Yeary

6

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL OF THE
COMMONWEALTH OF KENTUCKY
INITIAL REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 6) Is distributive generation being encouraged just for existing members, or are Independent Power Producers (IPP) that purchase no power from a cooperative being encouraged to provide power to the Big Rivers system. If IPPs are being encouraged as distributive generation, are they compensated at the cost of power to the member cooperatives?

Response) Big Rivers will encourage distributive generation to the extent that it is a feasible and viable option to meet Big Rivers' future power requirements. There is no IPP distributive generation on Big Rivers' system.

Witness) Bill Yeary

Item 7) The IRP considered only wind and biomass as renewable options. Please explain why Big Rivers has not considered low cost run-of-river hydro at the Cannelton and Smithland dams on the Ohio River, which are located in the Big Rivers service territory and which have significantly lower costs than the renewable options considered by Big Rivers.

Response) Wind and biomass were included as two options for renewables to compare to more traditional generation options. Appendix D shows that there are three years when energy will be needed from sources outside of Big Rivers' existing resources. The small amount of unserved energy indicates that Big Rivers is not in need of an energy resource with the LEM and SEPA contracts. Because Big Rivers can buy only what is needed for the three years of deficit, the purchase and commercial/industrial cases are lower cost alternatives than any generation option, whether renewable or non-renewable. When Big Rivers is in need of a high capacity factor energy resource, then a run-of-river hydro unit would make a logical resource alternative to be considered for future studies.

Witness) Armando de Leon
Burns & McDonnell

8

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL OF THE
COMMONWEALTH OF KENTUCKY
INITIAL REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 8) The biomass option considered by Big Rivers was a plantation-grown biomass. Please explain why Big Rivers did not consider the use of wood waste, primarily sawdust, which is readily available in large quantities in the Big Rivers service territory, at no cost or just the cost of transportation.

Response) Although the use of wood waste streams is an option, Burns & McDonnell considers the consistent availability of fuel as a major issue for the biomass alternatives. When competing uses are made for the land or fuel supply, then the availability can be impacted and/or the price affected. Also, plantation grown fuel is expected to provide a more consistent fuel quality. A plantation approach provides contracts for the fuel with quality and delivery terms and conditions and is not dependent on another industry's waste stream. The situation where waste is a more viable alternative as a fuel is when the industry that is creating the waste is using it in its own facilities to offset buying either gas, steam or electric energy and can control the fuel more closely.

Witness) Armando de Leon
Burns & McDonnell

9

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE ATTORNEY GENERAL OF THE
COMMONWEALTH OF KENTUCKY
INITIAL REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 9) On pages IV-11 and 12 of the IRP, Big Rivers states that the two residential DSM programs considered are not cost effective. Please provide all the calculations, assumptions and work papers that were used to generate the costs for the programs as related in the IRP and to support the conclusions that were reached.

Response) The IRP filed by Big Rivers states on pages IV-11 and 12 that residential programs are "less cost-effective" [than their commercial-industrial counterparts]. No calculations or work papers were used in determining this.

Based on the 1995 study by R. W. Beck, the TRC and RIM scores were found to be 1.38 and 0.29 respectively for the water heater wrap program. Burns & McDonnell determined that no capacity deferrals are possible without an intensive program to rapidly saturate the residential market. The implementation of an intensive program would require greater investment over a shorter period of time. The same is true for a residential water heater timer program, with the implementation costs being somewhat higher.

Since Big Rivers would see no capacity credits from either program, the need for investment, low RIM score, and passing but low (best case) TRC score make the programs much less appealing than their commercial-industrial counterparts.

Witness) Armando de Leon
Burns & McDonnell

RECEIVED
JUN 19 2000
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

In the Matter of:

The Integrated Resource Plan of)
Big Rivers Electric Corporation) Case No. 99-429

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

Items 1-23

June 19, 2000

1

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 1) The volume submitted to the Commission in this case is titled the "1999 Integrated Resource Plan for Big Rivers Electric Corporation." The first sentence of the Executive Summary states that this Integrated Resource Planning Study for Big Rivers Electric Corporation was prepared by Burns & McDonnell to meet the requirements of the Commission's IRP regulation and to serve as a guide for Big Rivers in planning its resources to meet future system demands. The 3-year plan (pp.I-15 to I-16) takes the form of a set of recommendations from the consultants to Big Rivers. The second part of the volume consists of the "1999 Power Requirements Study for Big Rivers Electric Corporation," which was also prepared by Burns & McDonnell. Has Big Rivers adopted the Integrated Resource Planning Study and the 1999 Power Requirements Study as its 1999 Integrated Resource Plan?

Response) Yes

Witness) Bill Yeary

2

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 2) The cover of the volume includes a logo and the phrase, "A Touchstone Energy® Partner." Please describe the benefits or services Big Rivers presently receives by virtue of being a Touchstone Energy® Partner.

Response) Touchstone Energy® is a national brand identity program open to electric cooperatives across the country. The branding program was designed to help coops distinguish themselves as preferred providers of electricity in an increasingly competitive electric utility marketplace. Big Rivers benefits from the brand equity created by Touchstone Energy's® national multi-media advertising campaign, which focuses on four core cooperative values – integrity, commitment to community, accountability, innovation. Big Rivers leverages that brand equity by adding the Touchstone Energy® co-brand signature to all company signage and printed materials. Increased customer awareness of the values associated with Touchstone Energy® will enhance Big Rivers' efforts to retain customers and maintain low electric rates.

Witness) Mike Core

3

Item 3) Please describe the terms of Big Rivers' arrangement with LG&E Energy Marketing (LEM), whereby Big Rivers owns but does not operate generating facilities. If certain contracts or other documents (in part or in whole) would shed light on this question, please provide a copy of the documents or any relevant pages.

Response) Big Rivers Electric Corporation ("Big Rivers" or the "Company") is an electric generation and transmission cooperative corporation that provides wholesale electric service to three member electric distribution cooperatives (the "Members") and markets power to non-Member utilities and power marketers. Big Rivers' generating capacity is approximately 1,459 (net) megawatts and in 1998 its plants generated approximately 11,000 gigawatt-hours of electricity. During 1999, the Company's wholesale rates were approximately $36.44 and $30.47 per megawatt-hour for its rural and industrial loads, respectively. On a weighted average basis, its wholesale rates are approximately $33.78 per megawatt-hour. Big Rivers supplies power to its Members pursuant to wholesale power contracts which require, with limited exceptions, its Members to buy and receive all of their power and energy requirements from Big Rivers (the "Wholesale Power contracts").

The Members are local, consumer-owned distribution cooperatives providing retail electric service on a not-for-profit basis. The Members consist of Kenergy Corp. ("Kenergy"), Meade County Rural Electric Cooperative Corporation and Jackson Purchase Energy Corporation. The customer base of the Members generally consists of residential, commercial and industrial customers within specific geographic areas. Today, the Members provide electric power and energy to customers located in portions of 22 western Kentucky counties. The Members directly serve over 98,000 retail customers.

On September 25, 1996, Big Rivers filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code ("Chapter 11"). Big Rivers then operated as a debtor-in-possession under the supervision of the United States Bankruptcy Court for the Western District of Kentucky (the "Bankruptcy Court"). On June 9, 1997, the Bankruptcy Court confirmed a Plan of Reorganization proposed by Big Rivers (the "Plan of Reorganization"). On June 1, 1998 the Bankruptcy Court approved certain modifications to the Plan of Reorganization (as modified, the "Plan"). Big Rivers emerged from bankruptcy on July 15, 1998 (the "Effective Date").

Upon the implementation of the Plan, Big Rivers and LG&E Energy Corp. (LEC) and certain of its affiliates entered into certain transactions pursuant to which Big Rivers leased its generating facilities to an affiliate of LEC for a term of approximately twenty-five years (the "LG&E Transaction Term").

For the term of the LG&E Transaction, Big Rivers has leased its generating plants consisting of the 420 megawatt Wilson Facility, the 454 megawatt Green Facility, the 455 megawatt Kenneth C. Coleman Plant, the 65 megawatt Robert A. Reid Plant, and the 65 megawatt Reid Combustion Turbine (together, the "Generation Assets") to Western Kentucky Energy Corp., ("WKEC") a wholly owned subsidiary of LEC pursuant to a Lease and Operating Agreement dated July 15, 1998 (the "LG&E Lease"). Pursuant to the LG&E Lease, WKEC operates the Generation Assets.

Prior to entering into the LG&E Transaction, Big Rivers had entered into certain arrangements with the City of Henderson, Kentucky ("Henderson") whereby Big Rivers leased the Henderson Municipal Power and Light Station Two generating Facility (the "Station Two Facility") from Henderson. Big Rivers operated the Station Two Facility and was also entitled to the excess capacity and energy produced by the station and not taken by Henderson. On the Effective Date, LEC, through WKE Station Two Inc. (the "Station Two Subsidiary" and, collectively with LEC, LG&E Energy Marketing ("LEM) and WKEC, the "LG&E Entities"), also assumed certain of Big Rivers' obligations to Henderson pursuant to the underlying contracts between the Company and Henderson.

In order to fulfill its obligation to supply power to the Members and others following the Effective Date, Big Rivers purchases energy from LEM pursuant to a power purchase agreement, dated the Effective Date, between Big Rivers and LEM (the "Power Purchase Agreement"). In addition, Big Rivers has agreed to provide transmission services over its transmission network to LEM at open-access transmission tariff rates (subject to an annual minimum of $5 million.)

Beginning in July 2000, WKEC will pay Big Rivers monthly lease payments totaling approximately $31 million per annum. These monthly payments are subject to adjustment for certain environmental costs associated with operations and maintenance of the Generation Assets and changes in the amount of power purchased by Big Rivers from LEM over the LG&E Transaction Term. Finally, the Station Two Agreement subjects the monthly fixed payments to adjustment if the output from the Station Two Facility, in excess of Henderson's needs, generally is not available to LEM or the Station Two Subsidiary because of certain actions of Big Rivers.

As part of the LG&E Transaction, Big Rivers agreed to transfer to WKEC the right to deliver power to Kenergy for Kenergy to resell to two industrial customers operating as aluminum smelters, NSA, Inc., a subsidiary of Southwire Company ("Southwire"), and Alcan Aluminum Corporation ("Alcan" and, collectively with Southwire, the "Smelters"). In return, each month from the Effective Date through January 2012, WKEC will pay to Big Rivers amounts that total approximately $260 million (the "Smelter Margin Payments"). These payments are intended to compensate Big Rivers for the loss of margins it anticipated receiving from the sale of power to the Smelters. Prior to the implementation of the LG&E Transaction, the Smelters accounted for approximately two-thirds of the energy purchased by the Members from Big Rivers.

Big Rivers and WKEC will share certain costs relating to the Generation Assets, including property taxes, capital expenditures which are necessary to maintain the

Generation Assets or to comply with the requirements of applicable law, and certain increased operation and maintenance costs attributed to a change in environmental law after the Effective Date. The portion of each of these costs to be borne by each party will change during the LG&E Transaction Term to reflect changes in the maximum and minimum annual and hourly power purchase amounts under the Power Purchase Agreement in 2011, again in 2012, and if Big Rivers elects to reduce the maximum and minimum annual and hourly power purchase amounts.

Also on the Effective Date, WKEC leased the Generation Assets from Big Rivers pursuant to the LG&E Lease. Similarly, the Station Two Subsidiary assumed certain obligations of Big Rivers relating to the operation of the Station Two Facility. WKEC (with respect to the Generation Assets) and the Station Two Subsidiary (with respect to the Station Two Facility) is responsible for the operation, maintenance, and management of the Generation Assets and the Station Two Facility, the oversight of the design, construction and placing into service of all capital assets, and the development of an annual capital budget and annual operations and maintenance ("O&M") budget for the Generation Assets and the Station Two Facility.

Pursuant to the Power Purchase Agreement, LEM sells certain quantities of power to Big Rivers, subject to certain hourly and annual minimums and maximums and other contract requirements. The Power Purchase Agreement also sets out the consequences of Big Rivers failing to purchase the minimum contract amounts, the mechanism for adjusting the minimum and maximum limits, and the rates for purchased power over the LG&E Transaction Term.

The Power Purchase Agreement establishes minimum hourly and annual power purchase amounts, which Big Rivers is required to take, and certain maximum hourly and annual power purchase amounts LEM is required to make available to Big Rivers. These hourly and annual maximum and minimum quantities of power have been established at fixed quantities that change within four separate periods consisting of the period i) from the Effective Date through the end of 2000, ii) 2001 through the end of 2010, iii) the year 2011, and iv) from 2012 through 2023. The quantity adjustments are based on a forecast of Big Rivers' expected load requirements over the LG&E Transaction Term.

Together, the minimum hourly and annual power purchase amounts and the maximum hourly and annual power purchase amounts are the "Contract Limits". Power purchased by Big Rivers in amounts up to the maximum hourly and annual amounts is defined as "Base Power". Big Rivers will be responsible for arranging for above-Base Power purchases from third parties or from LEM under a separate agreement. Nonetheless, in addition to Base Power, LEM will provide power to Big Rivers to service Big Rivers' obligations under existing wholesale power sales agreements between Big Rivers and the City of Henderson Utility Commission, doing business as Henderson Municipal Power & Light ("HMP&L"), Big Rivers and Oglethorpe Power Corporation ("Oglethorpe") and Big Rivers and Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier" and, collectively with Oglethorpe and HMP&L, the "Existing Off-System Wholesale Power Customers"). In exchange, Big Rivers will pay LEM any amounts Big Rivers actually collects for such power. The power sold to Existing Off-System Wholesale Power Customers will not be used in the calculation of annual or hourly minimum or maximum power purchase amounts.

Subject to the Contract Limits, Big Rivers may schedule and purchase any amount of Base Power from LEM. Still, Big Rivers is required to (i) buy no less than the lesser of the minimum Contract Limit or the amount Big Rivers actually sells to its Members to meet the load requirement of the Member's retail customers other than the Smelters or (ii) pay a minimum payment in lieu of such purchases. However, the Power Purchase Agreement does not prevent Big Rivers from paying this penalty in certain hours to purchase lower cost power, if available, from others or reselling a portion of it in other hours (excess to the needs of its Members) to a third party. Big Rivers also may purchase only its minimum obligation while purchasing additional power from other suppliers to meet its Members' loads in excess of the stated minimum (without penalty, provided both hourly and annual minimum obligations are met). As a result, Big Rivers is able to arbitrage power purchased from LEM. These arbitrage opportunities will be available in any hour in which Big Rivers' power purchase rate from the market plus any applicable hourly penalty in which such power is not taken from LEM is less than the amount which Big Rivers would be charged by LEM at Base Power rates or in which it can resell Base Power at a profit (after transaction costs).

The Power Purchase Agreement allows Big Rivers, subject to certain limitations, to adjust the Contract Limits downward at any time by giving written notice to LEM. Contract limit reductions are limited to a maximum of 12 MW in any one-year period and a maximum of 72 MW over the term of the Power Purchase Agreement. Once made, any such reduction will remain effective for a balance of the term of the Power Purchase Agreement. No reduction will occur until the expiration of two consecutive full calendar years after notice of such reduction has been given. Further, the minimum annual power purchase amount will not be permitted to be less than 102% of the loads of the Members (excluding the Smelters) in the prior year.

The Power Purchase Agreement obligates LEM to provide Big Rivers Base Power generally at a fixed price. The rates charged by LEM to Big Rivers may be adjusted in 2004, 2011 and 2018 based on the Coal Index (DRI Price of Coal to Electric Utilities – National) and the Labor Index (DRI Unit Labor Cost – National) and the comparison of a calculated reference rate against specified baseline rates set forth in the Power Purchase Agreement. Because the baseline rates are set at relatively wide ranges, Big Rivers does not anticipate that rates will change during the term of the Power Purchase Agreement based on adjustments for fuel and labor costs.

As a transmission control area operator, Big Rivers requires certain power-related ancillary services to operate its transmission system and to maintain the reliability of the service provided to loads in Big Rivers' control area. In order to provide certain of the generation-related ancillary services required to be provided by Big Rivers in its role as control area operator, Big Rivers has contracted with LEM to supply the ancillary services. In addition to Base Power, LEM has agreed to provide certain specified quantities (the "Specified Quantities") of ancillary services as part of the price of Base Power.

LEM also provides quantities of ancillary services at no additional charge as part of the price of the power sold by LEM to Big Rivers for subsequent resale to the Existing Off-System Wholesale Power Customers. To the extent Big Rivers requires ancillary services at levels in excess of the Specified Quantities, LEM has agreed to supply the requested quantities of service, at separate cost, as needed by Big Rivers in its role as control area operator. These additional quantities of ancillary services will be provided by LEM to Big Rivers at cost-based rates under tariffs approved by the Federal Energy Regulatory Commission ("FERC"). Big Rivers will in turn pass through to its transmission customers these additional costs as applicable under its transmission tariff.

Throughout the LG&E Transaction Term, Big Rivers will retain its existing obligations under the Wholesale Power Contracts with the Members as modified with respect to termination of Big Rivers' obligation to supply power to the Members for resale to the Smelters. Moreover, Big Rivers will retain all rights arising under existing wholesale power purchase agreements with the Off-System Wholesale Power Customers (the "Existing Off-System Wholesale Power Contracts") throughout the remaining term of such contracts and certain extensions entered into, consistent with the Power Purchase Agreement. Big Rivers will continue to perform its obligations with respect to the Existing Off-System Wholesale Power Contracts using power purchased from LEM. Upon expiration of the LG&E Transaction Term, control over the generation assets will revert to Big Rivers.

Big Rivers has entered into the Wholesale Power Contracts with each of the Members pursuant to which each Member purchases all of its electric power requirements from Big Rivers. The term of each of the Wholesale Power Contracts, as amended in connection with the Plan, will extend through January 1, 2023. None of the Wholesale Power Contracts, as amended, may be unilaterally terminated by a party, without cause, prior to January 1, 2023. Each Wholesale Power Contract, as amended, may be terminated by either party after January 1, 2023, upon six-month notice. The Wholesale Power Contract between Big Rivers and Kenergy has been amended on the Effective Date to permit the purchase of power by Kenergy from LEM for resale to the Smelters.

Prices under Big Rivers' Wholesale Power Contracts are at tariff rates approved by the Kentucky Public Service Commission. Requests for adjustments to the capacity charge and energy charge must be made to the Kentucky Public Service Commission. All of the contracts associated with this described transaction are too voluminous to provide. A copy of the agreements can be found at the Commission in Cases 97-204 and 98-267.

Witness) David A. Spainhoward

4

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 4) a. Is Big Rivers aware of any other member/customers planning to implement self-generation or cogeneration, other than the Kenergy member/customer that is planning to install 62 MW of power generation in spring 2001?

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

Response) a. No

b. Plans are moving forward to install the 62 MW of cogeneration on the Big Rivers' system. Big Rivers will encourage and cooperate with any industrial customer to install cogeneration facilities if it can be demonstrated that it is economically beneficial. Big Rivers has no additional quantitative information.

Witness) Bill Yeary

5

Item 5) Why is the voluntary Commercial/Industrial Load Management Program included in the Power Supply Screening analysis (Part III) rather than in the Demand-Side Management Screening Analysis (Part IV)?

Response) The Voluntary Curtailable Load Program can be modeled as either an additional supply-side resource or as a demand-reducing program. Most Integrated Resource Planning studies that evaluate this type of program model it as a supply-side resource because it is "dispatchable" by the utility in the same way that a distributed generation asset might likewise be dispatched.

Witness) Armando de Leon
Burns & McDonnell

6

Item 6) Point #4 of the three-year plan on page I-16 and page VII-3 states, "Big Rivers should encourage the use of distributed generation among its members to lower peak demands and energy requirements and provide Big Rivers with greater flexibility in its power supply operations."

a. Does Big Rivers have any programs now in effect, or in the planning stage, to encourage member/customers to install distributed generation systems? If so, please describe these programs and/or program plans.

b. It seems to the Kentucky Division of Energy (KDOE) that strategic conservation would also lower peak demands and energy requirements and provide Big Rivers with greater flexibility in its power supply operations. Why does the IRP recommend against strategic conservation, even though it appears to have beneficial characteristics and impacts similar to those of distributed generation?

Response) a. Big Rivers does not have any official programs in effect to encourage installation of distributed generation systems. However, as shown by the 62 MW cogeneration Big Rivers is certainly encouraging distributed generation.

b. While strategic conservation is within the realm of demand-side management, the converse is not also true. The goal of strategic conservation is to reduce overall consumption, with a primary focus on energy. This can, depending on the utility's loads, generators and overall characteristics, cause a decrease in sales with little decrease in revenue requirements, i.e., increasing rate pressure.

Big Rivers has an excellent load factor. The only type of measure, within the general category of DSM that will benefit both the utility and the customers, is one which will simultaneously shave peak and (may) fill valleys – hence Burns & McDonnell's recommendation for a curtailable program.

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Witness) Armando de Leon
Burns & McDonnell

7

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 7) a. Has Big Rivers considered the potential impact of net metering, as instituted in 30 other states and as outlined in legislation introduced in the U.S. Congress by Rep. Jay Inslee, which would require all retail electric suppliers to offer net metering service to retail customers that generate electricity using certain qualified technologies? [The proposed national legislation is titled the "Home Energy Generation Act."]

b. If net metering were to be instituted in the service area of Big Rivers and its member distribution cooperatives, what would be the estimated impact on energy use and demand over the next 15 years?

Response) a. The technologies that are effected by net metering, i.e. fuel cells and renewables, are not commercially viable at present and therefore Big Rivers does not feel that net metering will have a significant impact.

b. There is not sufficient information at this time to estimate the impact.

Witness) Armando de Leon
Burns & McDonnell

Item 8) a. Has Big Rivers availed itself to information from organizations such as E Source, which is a source of comprehensive information on energy efficiency technologies and programs?

b. To what extent, if any, was information from sources used in developing the IRP?

Response) a. Big Rivers receives information available from such sources through its membership with various other organizations. For instance, the National Rural Electric Cooperatives Association, to which Big Rivers is a member, is a member of E Source.

b. Information from such sources was used in the general understanding of DSM options for consideration.

Witness) Bill Yeary

9

Item 9) a. In developing the IRP, did Big Rivers perform a study to estimate the quantity of demand-side energy efficiency and load-shifting measures that would be available within its service area (i.e., a Technical Potential study), the cost of implementing such measures, and the revenue requirements that would be needed to acquire various portions of these potential resources through DSM programs?

b. If so, what is the size of these potential DSM resources?

Response) a. A detailed study of this type was completed for Big Rivers, in March of 1995 by R. W. Beck and Associates. Data from this study was used as Burns & McDonnell assisted in completing the Integrated Resource Planning process for Big Rivers in 1999. Big Rivers' member cooperatives are in the process of visiting the largest 25 energy users in each co-op service territory. During these visits the cooperatives attempt to identify companies who would be able and willing to curtail or load shift. Also, please refer to Big Rivers' response to the Commission Staff's initial request for information Item No. 4.

Witness) Armando de Leon
Burns & McDonnell/Russ Pogue

b. Big Rivers can only estimate at this point. This number will solidify as the member cooperatives continue their visits and the information is analyzed by Big Rivers.

Witness) Russ Pogue

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 10) Has Big Rivers estimated the square footage of residential, commercial, and industrial floor space that is being newly constructed each year in its service area? If so, what are the estimated square footage figures?

Response) No

Witness) Russ Pogue

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 11) Has Big Rivers surveyed the energy efficiency of the range of types of new buildings being constructed in its service area? If so, please provide the results of this analysis.

Response) No

Witness) Russ Pogue

12

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 12) Please provide a copy of the DSM Study undertaken by Big Rivers and prepared by R. W. Beck in 1995.

Response) A copy of the requested DSM Study is attached.

Witness) Bill Yeary

Final Report

BIG RIVERS ELECTRIC CORPORATION

CENTRALIZED COORDINATED DSM PLANNING STUDY

HENDERSON UNION

GREEN RIVER ELECTRIC

Jackson Purchase Electric Cooperative Corporation

MEADE COUNTY

March 1995

R·W·BECK

BIG RIVERS
CENTRALIZED COORDINATED
DSM PLANNING STUDY

TABLE OF CONTENTS

INTRODUCTION AND STUDY OVERVIEW

Big Rivers Electric Corporation (Big Rivers) and its four member distribution electric cooperatives (Coops), Green River Electric Corporation (Green River), Henderson-Union Rural Electric Cooperative Corporation (Henderson-Union), Jackson Purchase Electric Cooperative Corporation, (Jackson Purchase), and Meade County Rural Electric Cooperative Corporation (Meade County) have been working together to review recent developments occurring in the electric utility industry and the Commonwealth of Kentucky with respect to demand-side management (DSM). Big Rivers and the Coops have been developing joint marketing efforts to increase their respective system average annual load factors. In July of 1993, Big Rivers and the Coops selected R.W. Beck to investigate the strategies and overall objectives for undertaking DSM.

Included in the major work efforts of the project was performing a detailed DSM screening and cost-effectiveness analysis of each company carrying out its own DSM efforts and a detailed cost-effectiveness analysis of a centralized, coordinated effort by all five companies. This report documents the study approach used in the centralized, coordinated effort and a comparison of the individual company approach versus the centralized, coordinated approach. Based on the major findings presented, this report presents the recommendation of the centralized, coordinated approach as the least-cost alternative.

This report provides an overview of the study approach and discusses the major findings for each of the steps in the DSM planning process for the Big Rivers' centralized, coordinated (Big Rivers Centralized) approach.

The approach used in this study involved five major steps:

- Situation Analysis and Baseline Development
- Assessment of Individual Company Results
- Development of Centralized DSM Programs
- Cost-Effectiveness of Centralized Programs
- Comparison of Results

SITUATION ANALYSIS AND BASELINE DEVELOPMENT

During the Summer of 1994, a meeting was held with the Big Rivers' DSM committee to develop a strategic plan considering the strengths, weaknesses, opportunities, and threats as they related to the DSM process implemented from the Big Rivers Centralized approach.

A system profile was developed to provide a baseline against which potential DSM technologies and programs were compared. The system profile was developed using DSManager, the Electric Power Research Institute (EPRI) developed DSM planning model. Key inputs to the system profile included retail rate schedules, wholesale rate schedules, demand and energy forecasts, transmission line losses, marginal cost data, and financial parameters.

An additional step in the situation analysis was the analysis of the current DSM programs. Big Rivers participated in the Coops' 1994 marketing programs which offered incentive based programs for air source heat pumps, electric water heaters, and geothermal heat pumps. In addition, Big Rivers and the Coops offered the All Seasons Comfort Home Program. A detailed cost-effectiveness analysis was performed for each program based on actual program participation from January, 1992 through September, 1994. The perspectives used for this analysis were the total Resource Cost (TRC) and the Ratepayer Impact Measure (RIM).

- The TRC perspective measures benefits and costs from the perspective of the utility and its ratepayers as a whole. Since the utility and its ratepayers are taken as a whole, changes in the dollar amount that flow between them are ignored. Programs passing the TRC test result in a decrease in the average cost of energy services to all ratepayers.

- The RIM perspective measures costs and benefits from the perspective of net utility revenue or, the change in revenue less the change in costs. Programs that pass the RIM test result in lower average rates to all ratepayers.

The results of this analysis are presented in Table EX-1.

TABLE EX-1 BIG RIVERS CENTRALIZED CURRENT PROGRAMS BENEFIT/COST RATIOS		
Program	TRC Score	RIM Score
Air Source Heat Pumps		
• Electric to Electric	1.05	0.51
• Conversion to Electric	n/a	1.17
Electric Water Heaters		
• Electric to Electric	0.06	0.10
• Conversion to Electric	n/a	2.95
Geothermal Systems		
• Electric to Electric	0.05	0.13
• Conversion to Electric	n/a	0.42
All Seasons Comfort Home	0.19	0.25

ASSESSMENT OF INDIVIDUAL COMPANY RESULTS

The results from the individual company studies were assessed to determine a set of DSM technologies to be evaluated from the Big Rivers Centralized approach. These results provided the DSM technologies with the most potential which would be further evaluated for the Big Rivers system.

For each individual company recommended program (presented in the *DSM Planning Study* reports), the TRC and RIM perspective were calculated from the Big Rivers system perspective. Tables EX-2 and EX-3 list the individual company programs which were cost-effective for the Big Rivers system from the TRC and the RIM perspective respectively.

TABLE EX-2 BIG RIVERS CENTRALIZED INDIVIDUAL COMPANY RESULTS RECOMMENDED PROGRAMS - TRC		
Company	TRC Score	RIM Score
Henderson-Union		
Residential Water Heater Tank Wrap	1.41	0.30
Residential Low-flow Showerheads	1.13	0.31

TABLE EX-2 BIG RIVERS CENTRALIZED INDIVIDUAL COMPANY RESULTS RECOMMENDED PROGRAMS - TRC		
Company	**TRC Score**	**RIM Score**
Green River		
Residential Space Conditioning Efficiency	6.00	0.39
Meade County		
Residential Water Heating Improvements	1.13	0.30
Big Rivers		
Residential Water Heating Efficiency	1.38	0.26
Residential Space Conditioning Efficiency	2.02	0.89

TABLE EX-3 BIG RIVERS CENTRALIZED INDIVIDUAL COMPANY RESULTS RECOMMENDED PROGRAMS - RIM		
Company	**TRC Score**	**RIM Score**
Jackson Purchase		
Residential Heat Pump Replacement	n/a	1.42
Residential Electric Water Heater Replacement	n/a	3.79
Henderson-Union		
Residential Electric Water Heater Replacement	n/a	3.92
Green River		
Residential Electric Water Heater Replacement	n/a	3.79
Residential Heat Pump Replacement	n/a	1.39
Meade County		
Residential Electric Water Heaters	0.00	3.46
Big Rivers		
Residential Electric Water Heater Replacement	n/a	3.08
Residential Air Source heat Pump Replacement	n/a	3.92
Commercial Electric Water Heater Replacement	n/a	3.55
Commercial Air Source Heat Pump Replacement	n/a	1.13

DEVELOPMENT OF CENTRALIZED DSM PROGRAMS

The DSM technologies contained in the individual company recommended programs which passed the TRC or the RIM benefit/cost test for the Big Rivers' system were selected for further evaluation.

The list of DSM technologies selected for further evaluation are presented in Table EX-4 below:

TABLE EX-4
BIG RIVERS CENTRALIZED
SELECTED TECHNOLOGIES

Technology	Sector	Description
Electric Water Heater Tank Wrap	R	R-11 Water Heater Tank Wrap
Low-flow Showerheads and Fittings	R	2.3 gpm Low-flow Showerhead and 2 Faucet Aerators
Setback/Clock Thermostat	R	Programmable Thermostat-Electric Furnace
Heat Pump Conventional-Upgrade	R	Upgrade from Electric Furnace to Air Source Heat Pump 7.5 HSPF/12 SEER
Heat Traps	R	Water Heating Heat Traps
Water Heater Pipe Wrap	R	20 Feet R-5 Pipe Wrap Insulation
Heat Pump Ground Source-Replace	R	Replace Non-electric Heating System with Ground Source Heat Pump EER=13
Heat Pump Conventional-Replace	R	Replace Non-electric Heating System with Air Source Heat Pump HSPF=7.5
Electric Water Heater-Replace	R	Replace Non-electric Water Heater with Efficient Water Heater EF=.92
Electric Water Heater-Replace	C	Replace Non-electric Water Heater with Efficient Water Heater EF=.92
Air Source Heat Pump-Replace	C	Replace Non-electric Heating System with Unitary Packaged Air Source Heat Pump

Due to the limited number of potential technologies, in place of grouping technologies for program offering, each technology was treated as an individual program.

For each selected technology, administrative costs, rebate levels, and participation schedules determined in the individual company studies were reviewed and revised to reflect the Big Rivers Centralized approach.

COST-EFFECTIVENESS OF CENTRALIZED PROGRAMS

Cost-effectiveness results were determined for the eleven technologies or programs shown in Table EX-4. The cost-effectiveness calculations were performed using the DSManager model. Using the program information developed and the system profile developed, DSManager determined the cost-effectiveness for each program. DSManager calculated cost-effectiveness using all five of the perspectives that are defined by the California Standard Practice. For this study, the TRC and RIM perspectives were used.

- The TRC benefits include the avoided capacity or demand and energy or production costs. TRC costs include administrative costs and incremental DSM technology costs .
- The RIM benefits include the avoided capacity or demand and energy or production costs and increases in revenue to the utility. RIM costs include administrative costs, rebates, and decreases in revenue to the utility.

PROGRAM RECOMMENDATIONS

For this study, program recommendations were made based on the resulting benefit/cost ratios for both the TRC and the RIM perspectives.

TRC PROGRAMS

Four of the programs analyzed passed the TRC test, i.e. the benefit/cost ratio from the total resource perspective was greater than or equal to 1.0. Descriptions of each of the programs are presented below.

Program 1 - Residential - Electric Water Heater Tank Wrap

The residential electric water heater tank wrap program offers cash rebates to residential customers who purchase and install a water heater tank wrap with a minimum insulation value of R-11 to their electric water heater. Rebates are set at fifty percent of the cost of the tank wrap.

Program 2 - Residential - Low-Flow Showerheads and Fittings

The residential low-flow showerheads and fittings program offers cash rebates to residential customers with electric water heaters who purchase and install one low-flow showerhead, 2.3 gpm or less, and 2 faucet aerators. Rebates are set at fifty percent of the cost of the showerhead and faucet aerators.

Program 3 - Residential - Setback/Clock Thermostats

The residential setback/clock thermostats offers cash rebates to residential customers with electric furnaces who purchase and install a programmable thermostat. Rebates are set at fifty percent of the cost of the programmable thermostat.

Program 5 - Residential - Heat Traps

The residential heat traps program offers cash rebates to residential customers who purchase and install heat traps to their electric water heater inlet and outlet water connections. Rebates are set at fifty percent of the cost of the heat traps.

RIM PROGRAMS

Six of the programs analyzed passed the RIM test, i.e. the benefit/cost ratio from the ratepayer impact perspective was greater than or equal to 1.0. Descriptions of each of the programs are presented below.

Program 3 - Residential - Setback/Clock Thermostats

The residential setback/clock thermostats offers cash rebates to residential customers with electric furnaces who purchase and install a programmable thermostat. Rebates are set at fifty percent of the cost of the programmable thermostat.

Program 7 - Residential - Ground Source Heat Pump Replacement

The residential ground source heat pump replacement program offers cash rebates to residential customers with non-electric heating systems who purchase and install a ground source heat pump with a minimum EER=13. Rebates are set at fifty percent of the incremental cost of the ground source heat pump as compared to a natural gas furnace and standard central air conditioner.

Program 8 - Residential - Air Source Heat Pump Replacement

The residential air source heat pump replacement program offers cash rebates to residential customers with non-electric heating systems who purchase and install an air source heat pump with a minimum HSPF=7.5/SEER=12. Rebates are set at $100.00 per heat pump.

Program 9 - Residential - Electric Water Heater Replacement

The residential electric water heater replacement program offers cash rebates to residential customers with non-electric water heaters who purchase and install an efficient electric water heater a minimum EF=.92. Rebates are set at $50.00 per water heater.

Program 10 - Commercial - Electric Water Heater Replacement

The commercial electric water heater replacement program offers cash rebates to commercial customers with non-electric water heaters who purchase and install an efficient electric water heater a minimum EF=.92. Rebates are set at $50.00 per water heater.

Program 11 - Commercial - Air Source Heat Pump Replacement

The commercial air source heat pump replacement program offers cash rebates to commercial customers with non-electric heating systems who purchase and install an efficient unitary packaged air source heat pump with a minimum COP=3.2. Rebates are set at $100.00 per 1000 square feet of building space conditioned.

Table EX-5 presents a cost-effectiveness summary of both the TRC and the RIM recommended programs including program benefits and programs costs for both the TRC and the RIM perspectives.

TABLE EX-5
BIG RIVERS CENTRALIZED
COST-EFFECTIVENESS SUMMARY
($1994)

	TOTAL RESOURCE COST			RATEPAYER IMPACT MEASURE		
Program	**Program Benefits**	**Program Costs**	**Net Benefits**	**Program Benefits**	**Program Costs**	**Net Benefits**
Residential						
Elect Water Heater Tank Wrap	398,380	287,710	110,670	398,380	1,385,620	(987,240)
Low-flow Showerheads	460,630	386,910	43,720	430,630	1,559,690	(1,129,050)
Setback/Clock Thermostat	1,989,880	984,700	1,005,180	1,989,880	1,823,120	166,760
Heat Traps	316,460	128,970	187,490	316,460	1,118,250	(801,790)
Heat Pump Grd Srce Replace	n/a	n/a	n/a	5,686,480	5,499,620	186,860
Heat Pump Conv Replace	n/a	n/a	n/a	13,020,280	3,584,610	9,436,670
Electric Water Heater Replace	n/a	n/a	n/a	3,680,910	1,089,220	2,591,700

TABLE EX-5 BIG RIVERS CENTRALIZED COST-EFFECTIVENESS SUMMARY ($1994)						
	TOTAL RESOURCE COST			RATEPAYER IMPACT MEASURE		
Program	Program Benefits	Program Costs	Net Benefits	Program Benefits	Program Costs	Net Benefits
Commercial						
Water Heater Replacement	n/a	n/a	n/a	84,410	22,820	61,600
Air Source Heat Pump Replce	n/a	n/a	n/a	157,760	149,060	8,700

COMPARISON OF RESULTS

The results of the individual company approach and the results of the Big Rivers Centralized approach were compared using the TRC and RIM perspectives for the Big Rivers system.

To compare the effects of implementation of the two study approaches, DSM plans were created. The DSManager program will provide aggregated results of individual programs to provide the results of a comprehensive DSM plan. Using this feature, the Big Rivers Centralized study recommended programs were aggregated into the following DSM plans: recommended TRC programs and recommended RIM programs. In addition, the individual company results for the four Coops were aggregated into two comprehensive DSM plans; recommended TRC programs and recommended RIM programs. Table EX-6 presents a comparison of the total costs and savings for the study period, 1994-2007, in 1994 dollars for the Big Rivers system for each of the DSM plans.

TABLE EX-6 BIG RIVERS CENTRALIZED DSM PLAN RESULTS ($000)								
	Total Resource Cost Perspective				Ratepayer Impact Measure Perspective			
Plan	B/C Ratio	Plan Benefits	Plan Costs	Net Benefits	B/C Ratio	Plan Benefits	Plan Costs	Net Benefits
Centralized Plans								
TRC	1.75	3,135	1,788	1,347	0.53	3,135	5,887	(2,751)
RIM	n/a	n/a	n/a	n/a	2.45	21,040	8,588	12,452
Individual Company Plans								

TABLE EX-6 BIG RIVERS CENTRALIZED DSM PLAN RESULTS ($000)								
	Total Resource Cost Perspective				Ratepayer Impact Measure Perspective			
TRC	0.55	4,533	8,188	(3,655)	0.22	4,533	20,316	(15,783)
RIM	n/a	n/a	n/a	n/a	0.00	0	4,884	(4,884)

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

Based on the analyses performed in the preceding sections the following conclusions have been reached:

- The air source heat pump program, electric to electric installations, at current participation levels is cost-effective for Big Rivers from the TRC perspective under the Big Rivers Centralized approach.

- The air source heat pump, electric water heater, and geothermal programs, electric to electric installations, at current participation levels are not cost-effective for Big Rivers from the TRC or the RIM perspective under the Big Rivers Centralized approach.

- The air source heat pump and electric water heater programs, conversion to electric installations, at current participation levels are cost-effective for Big Rivers from the RIM perspective under the Big Rivers Centralized approach.

- The geothermal program, conversion to electric installations, at current participation levels, is not cost-effective for Big Rivers from the RIM perspective under the Big Rivers Centralized approach.

- The All Seasons Comfort Home Program, at current participation levels, is not cost-effective for Big Rivers from the TRC or the RIM perspective under the Big Rivers Centralized approach.

- For the twenty-five programs recommended from the TRC perspective in the individual company approach, six programs are cost-effective from the TRC perspective under the Big Rivers Centralized approach.

- For the fourteen programs recommended from the RIM perspective in the individual company approach, ten programs are cost-effective from the RIM perspective under the Big Rivers Centralized approach.

- Based on the results of the individual company approach and the two preceding conclusions, eleven centralized DSM programs were developed.

- Four of the eleven centralized programs developed were cost-effective from the TRC perspective for Big Rivers under the Big Rivers Centralized approach.

- Six of the eleven centralized programs developed were cost-effective from the RIM perspective for Big Rivers under the Big Rivers Centralized approach.

- Of the six RIM cost-effective programs, three of the programs are cost-effective from the RIM perspective for the distribution cooperatives taken collectively.

- Neither the RIM or TRC aggregate DSM plans for the individual company approach are cost-effective for Big Rivers under the Big Rivers Centralized approach.

RECOMMENDATIONS

The following recommendations are presented based on the analyses and conclusions presented in this study:

- The current wholesale rate structure does not provide accurate pricing signals based on Big Rivers current capacity situation. The current wholesale rate needs to be changed to accurately reflect Big Rivers current capacity situation and in turn to identify the appropriate DSM efforts to be undertaken by Big Rivers and the distribution cooperatives.

- The current design of the All Seasons Comfort Home program is not cost-effective from the TRC or the RIM perspective for Big Rivers or the distribution cooperatives and based on these results should be discontinued.

- The least-cost approach, given the current wholesale rate, is the Big Rivers Centralized approach. If the individual company results are implemented by the distribution cooperatives, based on the results presented, the cost to Big Rivers in terms of revenue reduction could range from approximately five million dollars to sixteen million dollars (1994 dollars) over the study period, depending on the programs implemented.

- If the Big Rivers Centralized RIM recommended programs are selected for implementation, for each of the six programs recommended, a joint marketing decision should be made to determine appropriate rebate levels and program designs. Rebate levels for this study for the electric water heater and air source heat pump replacement programs were set at minimum levels based on the minimal incremental costs incurred by the participants. If rebate levels are increased, a subsequent cost-effectiveness analysis should be performed to determine if the program is still cost-effective at the higher rebate level.

- Based on the current wholesale rate situation, very few programs are cost-effective from all five companies perspectives. Although a program is cost-effective for Big Rivers from the Big Rivers Centralized approach and for the distribution cooperatives collectively, this occurs with some programs because one or two of the companies experiences a substantial increase in costs due to the impacts of a program which is not cost-effective. This is due in most cases to increased demand charges resulting from a switch from summer to winter peaking. Based on Big Rivers current capacity situation and production costs, programs should not derive a benefit based on capacity or demand. If the wholesale rate provided accurate price signals, programs would only be cost effective from the TRC perspective if the avoided production (energy) costs exceeded the costs of administering the program plus the incremental cost of the DSM technology and from the RIM perspective if the increase in energy charges paid by the distribution cooperatives exceeded the increase in production costs plus the rebates and administrative costs incurred by Big Rivers. Therefore, the analyses performed provide internally inconsistent results due to the current wholesale rate structure. It is recommended that until the wholesale rate is corrected, DSM programs should be implemented only if they are consistent with the discussion presented above.

- Information regarding the commercial and small industrial customers is very limited and more information should be obtained before programs are designed for these sectors. The information used in this study for the commercial/industrial sectors was based on national averages and limited utility specific data. It is recommended that a database of commercial and industrial customers be developed to include information regarding market segment classification, square footage, electric end-uses, end-use usage or intensity, etc. Once this information is available, subsequent evaluations of the commercial/industrial programs should be performed to determine whether these programs should be designed for implementation.

1

INTRODUCTION AND STUDY OVERVIEW

BACKGROUND

Big Rivers Electric Corporation (Big Rivers) and its four member distribution electric cooperatives (Coops), Green River Electric Corporation (Green River), Henderson-Union Rural Electric Cooperative Corporation (Henderson-Union), Jackson Purchase Electric Cooperative Corporation, (Jackson Purchase), and Meade County Rural Electric Cooperative Corporation (Meade County) have been working together to review recent developments occurring in the electric utility industry and the Commonwealth of Kentucky with respect to demand-side management (DSM). Big Rivers and the Coops have been developing joint marketing efforts to increase their respective system average annual load factors. In July of 1993, Big Rivers and the Coops selected R.W. Beck to investigate the strategies and overall objectives for undertaking DSM. The scope of work included examining opportunities at each company individually as well as from a coordinated effort undertaken collectively by all five companies. The overall goal of the project was to make a recommendation as to which approach, the individual company approach or the centralized, coordinated approach, was the least-cost alternative for the parties involved.

Included in the major work efforts of the project was performing a detailed DSM screening and cost-effectiveness analysis of each company carrying out its own DSM efforts and a detailed cost-effectiveness analysis of a centralized, coordinated effort by all five companies. This report documents the study approach used in the centralized, coordinated effort and a comparison of the individual company approach versus the centralized, coordinated approach. Based on the major findings presented, this report presents the recommendation of the centralized, coordinated approach as the least-cost alternative.

This report provides an overview of the study approach and discusses the major findings for each of the steps in the DSM planning process for the Big Rivers' centralized, coordinated (Big Rivers Centralized) approach.

STUDY OVERVIEW

The approach used in this study involved five major steps:

- Situation Analysis and Baseline Development

- Assessment of Individual Company Results
- Development of Centralized DSM Programs
- Cost-Effectiveness of Centralized Programs
- Comparison of Results

The situation analysis and baseline development established a base case against which the impacts of potential DSM technologies could be compared and evaluated. In addition, the situation analysis assisted in the identification of the goals and objectives of Big Rivers undertaking DSM from a centralized, coordinated approach. Using the results of the detailed cost-effectiveness results of each individual company, centralized programs were developed to deliver the identified DSM technologies which were cost-effective from the centralized perspective. In this step, administrative costs, participation schedules, incentive levels, and other factors that affect the cost-effectiveness of potential DSM programs were reviewed and revised to reflect the Big Rivers Centralized approach. Next, the cost-effectiveness of each potential program was determined. In the final step, a comparison was made of the results of the individual company DSM program recommendations and the Big Rivers Centralized DSM program recommendations.

This report has seven sections. Section 1 contains this introduction and overview. Sections 2 through 6 discuss the five major steps as outlined above; and Section 7 concludes the report with the conclusions and recommendations based on the results of the analyses presented in the previous sections.

2

SITUATION ANALYSIS AND BASELINE DEVELOPMENT

The situation analysis was an initial identification of the strengths, weaknesses, threats, and opportunities impacting demand-side planning. These elements helped in identifying appropriate evaluation criteria and technology options which were reasonable and relevant given the Big Rivers' situation. The baseline development established the base case against which potential DSM opportunities were compared and evaluated.

IDENTIFICATION OF DSM OBJECTIVES

During the Summer of 1994, a meeting was held with the Big Rivers' DSM committee to develop a strategic plan considering the strengths, weaknesses, opportunities, and threats as they related to the DSM process implemented from the Big Rivers Centralized approach. For each of these categories, a process called "Pareto Voting" was used to prioritize the individual issues compiled through brainstorming sessions. Pareto Voting is a method which can be very effectively used to determine the most important issues of a group. A heterogeneous team was selected in order to get several perspectives on a topic. The relative significance of the various issues identified by brainstorming was quantified by using this method. Each person in the team was given a total of ten votes and he or she cast all ten of the votes, distributed among the identified issues, according to that person's perception of the relative importance of each issue.

The complete results of the Big Rivers Centralized organizational assessment are found in Appendix A. The primary goals and objectives as selected by Big Rivers' DSM committee during the organizational assessment are shown in ranked order on Table 2-1. Based on these utility goals and objectives, strategies and tactics were derived by the team members. A complete listing of Big Rivers' strategies and tactics is presented on Table 2-2.

TABLE 2-1 BIG RIVERS CENTRALIZED DEMAND SIDE MANAGEMENT GOALS	
Priority	**Goal**
1	Develop a long-term and a short-term DSM program that properly balances: - Big Rivers' revenue regulations - Include coop expenditures for DSM projects to benefit customers - Smelter - Industrial - Rural
2	Look at DSM from customers benefit ($).
3	Survival
3	DSM aspect of competition.
4	Time table - do we need DSM now?
5	Same playing field so that all are on the same wavelength to avoid conflicting strategies.
6	Consumer friendly - ease of use.
7	Base analysis on overall Big Rivers' cost.
8	Establish revenue neutral DSM program.
9	Develop plan to get to long-term plan.
10	What is DSM?

TABLE 2-2 BIG RIVERS CENTRALIZED DEMAND SIDE MANAGEMENT STRATEGIES AND TACTICS	
Priority	**Strategy**
1	Determine what consumer wants.
2	Develop a perspective for DSM evaluation
3	Implement short term and plan long-term
4	Explain a wholesale rate that reflects cost (as it relates to DSM).
5	Maintain high public profile.
5	Develop evaluation process for specific issues
6	Cost justify individual DSM projects
7	Explore retail rate that reflects cost (as it relates to DSM).

TABLE 2-2 BIG RIVERS CENTRALIZED DEMAND SIDE MANAGEMENT STRATEGIES AND TACTICS	
Priority	Strategy
8	Employee and board and consumer training.
8	Monitor, evaluate, measure results and resource requirements.
8	Coordinate - PRS - Financial forecast - Generation plan - DSM
9	Obtain regulatory approval
10	Update DSM issues at a minimum of every two years

DEVELOPMENT OF SYSTEM PROFILE

A system profile of the Big Rivers system was developed against which potential DSM technologies and programs were compared. The Electric Power Research Institute (EPRI) developed program, DSManager, was used as the DSM planning model for this project. Several data inputs were necessary to develop the system profile. General parameters assumed for the study are shown in Table 2-3. In addition to the Big Rivers system profile, each of the system profiles developed for the four Coops in the individual company studies were incorporated to reflect the power supplier/separate distributors model of the total Big Rivers' system. Table 2-4 lists additional parameters assumed in the Coop's system profiles.

TABLE 2-3 BIG RIVERS CENTRALIZED STUDY PARAMETERS		
Parameter	Value	Source
Base Year	1994	DSM Project Committee
Base Year Load Data	1991	DSM Project Committee
General Inflation	4%	R.W. Beck Value
Discount Rate	8.5%	1993 Big Rivers IRP
Retail Rate Escalation	1%	1993 Big Rivers IRP
Wholesale Rate Escalation	1%	1993 Big Rivers IRP
Transmission Loss Factor	2%	1993 Big Rivers IRP
Marginal Cost Data		1993 Big Rivers IRP

TABLE 2-4 BIG RIVERS CENTRALIZED MEMBER DISTRIBUTION COOPERATIVES STUDY PARAMETERS		
Parameter	**Value**	**Source**
Discount Rate (All Coops)	6.0%	Green River DSM Study
Distribution Loss Factor		1993 Update of the 1992 Power Requirements Study
- Green River	6.0%	
- Henderson-Union	8.6%	
- Jackson Purchase	6.6%	
- Meade County	7.5%	

The load forecast for the study period was taken from the *1993 Update of the 1992 Power Requirements Study*. Table 2-5 presents the energy and demand forecast values used in the Big Rivers system profile.

TABLE 2-5 BIG RIVERS CENTRALIZED ENERGY AND CP DEMAND FORECAST		
Year	**Energy (GWh)** [1]	**CP Demand (MW)** [2]
1993	8064	1129
1994	8201	1163
1995	8362	1173
1996	9468	1193
1997	8607	1226
1998	8359	1185
1999	8407	1195
2000	8456	1204
2001	8507	1215
2002	8565	1226
2003	8619	1237
2004	8674	1248
2005	8731	1259
2006	8789	1271
2007	8848	1282

TABLE 2-5 BIG RIVERS CENTRALIZED ENERGY AND CP DEMAND FORECAST		
Year	Energy (GWh) [1]	CP Demand (MW) [2]

[1] Source: Big Rivers Electric Corporation , 1993 Update of the 1992 Power Requirements Study, pg. 9.
[2] Source: Big Rivers Electric Corporation , 1993 Update of the 1992 Power Requirements Study, pg. 11.

The demand and energy forecasts for each Coop were taken from their respective *1993 Update of the 1992 Power Requirements Study*. Detailed information regarding the values used for each Coop is presented in each respective individual *DSM Planning Study* report.

ANALYSIS OF CURRENT DSM PROGRAMS

Big Rivers currently participates with the Coops in four DSM programs. Incentive based programs are offered for air-source heat pumps, electric water heaters, geothermal systems, and a home construction standards program. The programs for heat pumps and electric water heaters vary in design by Coop. Descriptions of each Coop's program designs are included in the individual *DSM Planning Study* reports. The home construction program, The All Seasons Comfort Home Program, is implemented by all four Coops using the same program design. A description of the All Seasons program is given below.

ALL SEASONS COMFORT HOME

The All-Seasons Comfort Home Program features special building and insulation standards designed for Kentucky's climate, as well as highly efficient heating and cooling systems. The following incentive payment is offered:

- $500 for meeting the All-Seasons Comfort Home Standards, $250 paid by the Coop and $250 paid by Big Rivers

A detailed cost-effectiveness analysis was performed based on the actual program participation through September, 1994 for each of the Coop's programs and for the All Seasons program. The perspectives used for this cost-effectiveness analysis were the Total Resource Cost (TRC) and the Ratepayer Impact Measure (RIM). Each of these perspectives is briefly discussed below :

- The Total Resource Cost perspective measures benefits and costs from the perspective of the utility and its ratepayers as a whole. Since the utility and its ratepayers are taken as a whole, changes in the dollar amount that flow between them are ignored. Programs passing the TRC test result in a decrease in the average cost of energy services to all ratepayers.

- The Ratepayer Impact Measure perspective measures costs and benefits from the perspective of net utility revenue or, the change in revenue less the change in costs. Programs that pass the RIM test result in lower average rates to all ratepayers.

For the heat pumps and electric water heater programs, the analysis for Big Rivers was performed by aggregating the individual Coop's programs. The electric to electric and conversion to electric participants were calculated based on survey information provided by Big Rivers' marketing staff. The resulting TRC and RIM benefit/cost ratios for the Big Rivers system are shown in Table 2-6:

TABLE 2-6
BIG RIVERS CENTRALIZED
CURRENT PROGRAMS
BENEFIT/COST RATIOS

Program	TRC Score	RIM Score
Air Source Heat Pumps		
• Electric to Electric	1.05	0.51
• Conversion to Electric	n/a	1.17
Electric Water Heaters		
• Electric to Electric	0.06	0.10
• Conversion to Electric	n/a	2.95
Geothermal Systems		
• Electric to Electric	0.05	0.13
• Conversion to Electric	n/a	0.42
All Seasons Comfort Home	0.19	0.25

3

ASSESSMENT OF INDIVIDUAL COMPANY RESULTS

The individual company results were assessed to determine a set of DSM technologies to be evaluated from the Big Rivers Centralized approach. These results provided the DSM technologies with the most potential which would be further evaluated for the Big Rivers system.

INDIVIDUAL COMPANY SCREENING PROCESS

The DSM technologies screened in the individual company analysis were subjected to a series of analyses in order to arrive at the cost-effective programs recommended for each company. Figure 3-1 displays the process used in the DSM planning process for each individual company. Details of each stage of the analysis are provided in the individual company *DSM Planning Study* reports. The following paragraphs briefly describe each of the major steps in the overall screening process.

QUALITATIVE SCREENING OF DSM TECHNOLOGIES

The qualitative screening of DSM technologies was performed in order to: 1) review a complete list of identified DSM technologies; 2) identify any specific factors that limited the applicability of a technology to the utility; and 3) eliminate the technologies that were inappropriate for the goals and objectives of the utility.

The comprehensive list of DSM technologies for each of the major customer classes was as defined in the Federal Register 40 CFR Subpart F, Appendix A. The 314 DSM technologies listed were subjected to a qualitative screening by each company's DSM team. Using the screening criteria and the screening criteria weighting factors developed in the organizational assessments the 314 technologies were rated by each company's DSM team. The results were ranked in descending order. Using this process, the DSM technologies with the highest scores were identified as the best suited to achieve the goals of the respective utility. The top 50 ranked technologies were selected for further analysis for each company.

In addition to the qualitative screening, a technical potential analysis was also performed at this stage. DSM technologies with limited market segment applicability or technologies with impacts and costs that could not be readily quantified were excluded from further analysis.

DSM PLANNING PROCESS

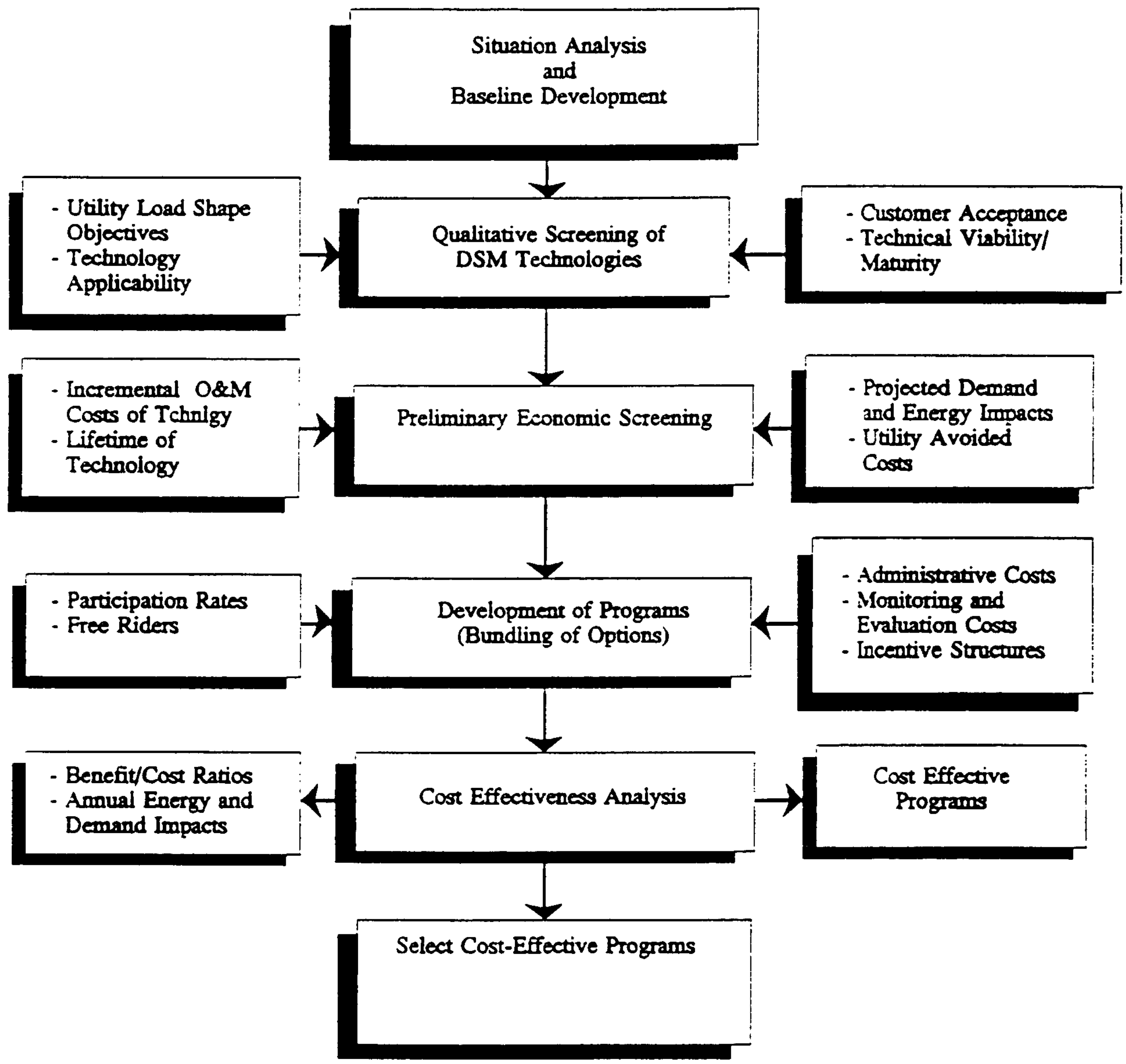


Figure 3-1

PRELIMINARY ECONOMIC SCREENING

The preliminary economic screening was the second analysis in the overall screening process that was used to identify a subset of potential DSM technologies. At this stage, the cost-effectiveness of individual DSM technologies was determined. The preliminary economic screening views cost-effectiveness from the TRC perspective.

In preparation for the preliminary economic screening, each DSM technology was formally defined by pairing the DSM technology, or high-efficiency technology, with a standard technology, or the technology the DSM technology would replace. Each technology, DSM and standard, was then characterized using the following parameters: technology life, technology capital cost, technology operation and maintenance (O&M) costs, and technology demand and energy impacts.

Technology life and technology capital and O&M costs were determined using data available from several sources including the R.W. Beck data base, data from the EPRI, the Western Area Power Administration *DSM Pocket Guidebook*, the American Council for an Energy Efficient Economy, and other available sources. The capital and O&M costs were determined for both the standard and DSM technologies to calculate the incremental costs associated with each DSM technology. The incremental capital cost is the cost a program participant incurs to install the DSM technology as compared to the standard technology. In assessing the costs associated with a DSM technology, the value of interest is the incremental cost.

The demand and energy impacts for each DSM technology were estimated using several methodologies including engineering estimates, field results, and building simulation results. For most weather sensitive technologies building simulation analyses were performed. A prototype house was developed for each Coop based on the results of the Residential Customer Class Questionnaires shown in the *DSM Planning Study-Appendices*. The EPRI developed simplified program for residential energy (ESPRE) computer model was used to determine energy consumption patterns for the prototype residential buildings.

For technologies which were not weather sensitive, engineering calculations were used to determine the consumption impacts. In some cases, the load impacts of the DSM technology were determined using the results of actual program experience.

The selected DSM technologies for each company were compared to their system profile using DSManager to determine the benefits and costs derived from each individual technology. The resulting benefits and costs were expressed using the TRC perspective. (Note: For measures which were loading building, since the TRC perspective was not applicable, the RIM perspective was used at this stage.)

After completing the preliminary economic screening, a second technical potential analysis of the passing technologies was performed. In some cases, passing technologies applied to such a limited market segment that they were excluded from further analysis.

DEVELOPMENT OF PROGRAMS

After completing the preliminary economic screening, passing technologies were bundled or packaged into logical groupings for possible program offering. At this stage, for each program, administrative program costs, incentive levels, and program participation schedules were developed.

Administrative cost estimates were derived based on a study prepared by the Oak Ridge National Laboratory, *The Administrative Costs of Energy Conservation Programs*, Linda Berry, November 1989. Administrative costs for residential technologies were calculated at twenty percent of incremental investment costs. Administrative costs for commercial lighting technologies were calculated at ten percent of incremental investment costs. Administrative costs for all other commercial technologies were calculated at thirty percent of incremental investment costs.

For this study, rebates for each technology were calculated at fifty percent of incremental investment costs and additionally constrained to not exceed one hundred percent of avoided costs, i.e. the avoided capacity and energy charges.

The eligible market segments and resulting eligible participants were identified for each Coop. The market segments identified were as follows: residential, including single family and multi-family customers, commercial-retail, commercial-restaurant, commercial-grocery, commercial-office, commercial-school, and commercial-warehouse. The population of the residential market segment for each Coop was taken from their respective 1993 Update of the 1992 Power Requirements Study 1993-2007, REA Form 736B (Rev. 5-25). The commercial market segment populations for each Coop were based on the breakdowns of commercial customers provided by each Coop's marketing staff.

The customers in the eligible market segments that would be eligible to implement the technology were determined using different approaches for the residential sector and the commercial and industrial sector. For the residential sector, the customers eligible to participate were determined using current market saturations of the standard technologies. The source of the market saturations was the *Big Rivers Electric Corporation Customer Satisfaction Survey, April, 1993.* For the commercial and industrial sectors, the customers eligible to participate were derived using national survey results.

After determining the annual eligible participants, a participation rate was applied to the annual eligible participants value to determine the estimated annual program participants. Secondly, a free rider rate was applied to the estimated annual program participants to determine the estimated annual number of free riders. Participation rates ranged from 20% to 30% and free rider rates ranged from 0% to 10%.

COST-EFFECTIVENESS ANALYSIS

The cost-effectiveness calculations were performed using the DSManager model. Using the program information developed and the system profiles developed, DSManager determined the cost-effectiveness for each program. DSManager calculated cost-effectiveness using all five of the perspectives that are defined by the California Standard Practice. For this study, the TRC and RIM perspectives were used.

INDIVIDUAL COMPANY RESULTS

For each company, program recommendations were made based on the results of the cost-effectiveness analysis of the proposed programs. Two sets of recommended programs were presented: 1)TRC passing and 2)RIM passing.

- The TRC test takes a relatively broad perspective by encompassing the utility and its ratepayers, but not all of society. Programs passing the test result in lower energy service costs within the utility's service territory, although no consideration is given to the distribution of costs and savings among different groups of customers.

- The RIM test measures costs and benefits form the perspective of net utility revenue. Programs passing the RIM test result in lower average rates to the utility's customers. There is no explicit consideration of different ratepayer groups.

For each individual company recommended program, the TRC and RIM perspective were calculated from the Big Rivers system perspective. Tables 3-1 and 3-2 list the individual company's programs which were cost-effective for the Big Rivers system from the TRC and the RIM perspective respectively. Exhibits 3-1 and 3-2 at the end of this section list each company's recommended programs and the resulting TRC and RIM scores respectively for the Big Rivers system.

TABLE 3-1
BIG RIVERS CENTRALIZED
INDIVIDUAL COMPANY RESULTS
RECOMMENDED PROGRAMS - TRC

Company	TRC Score	RIM Score
Henderson-Union		
Residential Water Heater Tank Wrap	1.41	0.30
Residential Low-flow Showerheads	1.13	0.31
Green River		
Residential Space Conditioning Efficiency	6.00	0.39
Meade County		
Residential Water Heating Improvements	1.13	0.30
Big Rivers		
Residential Water Heating Efficiency	1.38	0.26
Residential Space Conditioning Efficiency	2.02	0.89

TABLE 3-2 BIG RIVERS CENTRALIZED INDIVIDUAL COMPANY RESULTS RECOMMENDED PROGRAMS - RIM		
Company	TRC Score	RIM Score
Jackson Purchase		
Residential Heat Pump Replacement	n/a	1.42
Residential Electric Water Heater Replacement	n/a	3.79
Henderson-Union		
Residential Electric Water Heater Replacement	n/a	3.92
Green River		
Residential Electric Water Heater Replacement	n/a	3.79
Residential Heat Pump Replacement	n/a	1.39
Meade County		
Residential Electric Water Heaters	0.00	3.46
Big Rivers		
Residential Electric Water Heater Replacement	n/a	3.08
Residential Air Source heat Pump Replacement	n/a	3.92
Commercial Electric Water Heater Replacement	n/a	3.55
Commercial Air Source Heat Pump Replacement	n/a	1.13

EXHIBIT 3-1 BIG RIVERS CENTRALIZED INDIVIDUAL COMPANY RESULTS RECOMMENDED PROGRAMS - TRC		
Company	**TRC Score**	**RIM Score**
Jackson Purchase		
Residential Direct Load Control	0.03	0.01
Residential Water Heating Efficiency	0.94	0.29
Residential Efficient Air Source Heat Pump	0.49	0.46
Commercial/Industrial Efficient Lighting	0.30	0.27
Commercial/Industrial HVAC Controls	0.77	0.51
Commercial/Industrial Water Heating Efficiency	0.41	0.31
Henderson-Union		
Residential Water Heater Tank Wrap	1.41	0.30
Residential Low-flow Showerheads	1.13	0.31
Residential Dimmers	0.53	0.38
Residential Pipe Wrap Insulation	0.30	0.31
Residential Heat Pump Upgrade	0.53	0.49
Green River		
Residential Water Heating Improvements	0.94	0.29
Residential Direct Load Control	0.02	0.01
Residential Space Conditioning Efficiency	6.00	0.39
Residential Lighting	0.51	0.32
Commercial/Industrial Lighting	0.27	0.27
Meade County		
Residential Water Heating Improvements	1.13	0.30
Residential AC Direct Load Control	0.03	0.01
Residential Water Heater Direct Load Control	0.02	0.01
Residential Lighting	0.52	0.38
Commercial/Industrial Water Heating Improvements	0.56	0.31
Commercial/Industrial Lighting	0.32	0.23
Commercial Ceiling Fans	0.12	0.13
Big Rivers		
Residential Water Heating Efficiency	1.38	0.26
Residential Space Conditioning Efficiency	2.02	0.89

EXHIBIT 3-2 BIG RIVERS CENTRALIZED INDIVIDUAL COMPANY RESULTS RECOMMENDED PROGRAMS - RIM		
Company	**TRC Score**	**RIM Score**
Jackson Purchase		
Residential Heat Pump Replacement	n/a	1.42
Residential Electric Water Heater Replacement	n/a	3.79
Residential Direct Load Control	0.03	0.01
Henderson-Union		
Residential Electric Water Heater Replacement	n/a	3.92
Green River		
Residential Direct Load Control	0.02	0.01
Residential Electric Water Heater Replacement	n/a	3.79
Residential Heat Pump Replacement	n/a	1.39
Meade County		
Residential Electric Water Heaters	0.00	3.46
Residential AC Direct Load Control	0.03	0.01
Residential Water Heater Direct Load Control	0.02	0.01
Big Rivers		
Residential Electric Water Heater Replacement	n/a	3.08
Residential Air Source Heat Pump Replacement	n/a	3.92
Commercial Electric Water Heater Replacement	n/a	3.55
Commercial Air Source Heat Pump Replacement	n/a	1.13

4

DEVELOPMENT OF CENTRALIZED DSM PROGRAMS

The DSM technologies contained in the individual company's recommended programs which passed the TRC or the RIM benefit/cost test for the Big Rivers' system were selected for further evaluation.

DETERMINATION OF TECHNOLOGY GROUPINGS

The list of DSM technologies selected for further evaluation are presented in Table 4-1 below:

TABLE 4-1
BIG RIVERS CENTRALIZED
SELECTED TECHNOLOGIES

Technology	Sector	Description
Electric Water Heater Tank Wrap	R	R-11 Water Heater Tank Wrap
Low-flow Showerheads and Fittings	R	2.3 gpm Low-flow Showerhead and 2 Faucet Aerators
Setback/Clock Thermostat	R	Programmable Thermostat-Electric Furnace
Heat Pump Conventional-Upgrade	R	Upgrade from Electric Furnace to Air Source Heat Pump 7.5 HSPF/12 SEER
Heat Traps	R	Water Heating Heat Traps
Water Heater Pipe Wrap	R	20 Feet R-5 Pipe Wrap Insulation
Heat Pump Ground Source-Replace	R	Replace Non-electric Heating System with Ground Source Heat Pump EER=13
Heat Pump Conventional-Replace	R	Replace Non-electric Heating System with Air Source Heat Pump HSPF=7.5
Electric Water Heater-Replace	R	Replace Non-electric Water Heater with Efficient Water Heater EF=.92
Electric Water Heater-Replace	C	Replace Non-electric Water Heater with Efficient Water Heater EF=.92
Air Source Heat Pump-Replace	C	Replace Non-electric Heating System with Unitary Packaged Air Source Heat Pump

Due to the limited number of potential technologies, in place of grouping technologies for program offering, each technology was treated as an individual program at this stage.

DEVELOPMENT OF PROGRAM PARAMETERS

For each selected technology, administrative costs, rebate levels, and participation schedules determined in the individual company studies were reviewed and revised to reflect the Big Rivers Centralized approach.

ADMINISTRATIVE COSTS

Administrative costs estimates were derived based on the study referenced in Section 3, *The Administrative Costs of Energy Conservation Programs,* Linda Berry, November, 1989. The summary of this report says, "In general, the data show that an administrative cost ratio, i.e. administrative costs/installed DSM technology costs, of 0.20 is a reasonable average figure for residential programs. Commercial audit and incentive programs aimed at all end-uses have higher administrative cost ratios, in the range of 0.25 to 0.35. Commercial lighting programs have lower administrative costs, in the range of 0.10 to 0.15." Administrative costs for residential technologies were calculated at twenty percent of incremental investment costs and thirty percent of incremental costs for commercial technologies.

For the programs offering technologies offered in current programs, estimates of administrative costs were based on actual 1994 administrative costs provided by Jackson Purchase. Administrative costs for ground source heat pumps, air source heat pumps, and electric water heaters were based on this information.

Since the programs are administered by the Coop's member services departments, ninety percent of the total administrative costs were assumed to be incurred by the Coops and ten percent of the total administrative costs were assumed to be incurred by Big Rivers as the overall program administrator.

REBATE LEVELS

As a general rule, rebates are constrained to be less than or equal to one hundred per cent of incremental investment cost, i.e. a participant should not receive more of an incentive than the additional cost he is incurring, and less than or equal to one hundred per cent of avoided costs, i.e. the cost of the rebate should not exceed the savings the utility incurs in avoided capacity and production costs. As in the individual company studies, rebates for each technology were calculated at fifty percent of incremental investment costs and additionally constrained to not exceed one hundred percent of avoided costs. For the load building or replacement technologies, the constraint of avoided costs was not applicable and the incremental cost for some technologies was negligible or even negative (a savings). Therefore, the general rule could not be applied. In these cases rebate levels were arbitrarily estimated. For example, rebate levels for the following technologies; air source heat pump replacement and electric water heater replacement, were set at $100.00/unit and $50.00/unit respectively.

For this study, rebates were evenly split between the Coops and Big Rivers.

PARTICIPATION SCHEDULES

The eligible market segments and resulting eligible participants were identified for each Coop to derive the total Big Rivers values. The market segments identified were as follows: residential, including single family and multi-family customers, commercial-retail, commercial-restaurant, commercial-grocery, commercial-office, commercial-school, and commercial-warehouse. The population of the residential market segment for each Coop was taken from their respective 1993 Update of the 1992 Power Requirements Study 1993-2007, REA Form 736B (Rev. 5-25). The commercial market segment populations for each Coop were based on the breakdowns of commercial customers provided by each Coop's marketing staff. The eligible market segments identified for a given technology were based on the targeted end-use and the DSM technology's definition.

The next step was to determine the customers in the eligible market segments that would be eligible to implement the technology. Different approaches were used for the residential sector and the commercial and industrial sector. For the residential sector, the customers eligible to participate were determined using current market saturations of the standard technologies. The source of the market saturations was the *Big Rivers Electric Corporation Customer Satisfaction Survey, April, 1993.* For example, for each Coop, the number of eligible participants for electric water heater tank wraps was derived by multiplying the market segment total population for the first year of the program by the current market saturation of electric water heaters. This value represented the total number of water heaters in the market segment for the program start year, 1995. Since this technology was a retrofit technology, the program life was assumed to be five years and the annual eligible participants for each Coop were determined by dividing the total number of water heaters by five. In addition to this value, a market growth value was also determined. Based on the estimated annual population values from the above referenced reports, the number of additional water heaters added to the market each year for each Coop was determined using the respective current market saturation values. This market growth component for each year was then added to the current market value to yield the total water heaters in the market for each year of the program for each Coop.

For the commercial/industrial market segments, annual eligible participants were estimated by determining the total number of standard technologies in the market using estimates of average end-use energy usage or average square footage. Estimates of end-use energy usage were taken from the *Commercial Buildings Energy Consumption and Expenditures 1989*, a survey performed by the Energy Information Administration.

After determining the annual eligible participants, a participation rate was applied to the annual eligible participants value to determine the estimated annual program participants. Secondly, a free rider rate was applied to the estimated annual program participants to determine the estimated annual number of free riders. The total participants and free riders for each technology for the Big Rivers system were derived by aggregating the Coop values in the DSManager program.

5

COST-EFFECTIVENESS OF CENTRALIZED PROGRAMS

A detailed cost-effectiveness analysis of the programs developed in the preceding section was performed to assist in the recommendation of programs for the Big Rivers Centralized approach.

DETERMINE COST-EFFECTIVENESS

Cost-effectiveness results were determined for the eleven technologies or programs shown in Section 4. The cost-effectiveness calculations were performed using the DSManager model. Using the program information developed in Section 4 and the system profile developed in Section 2, DSManager determined the cost-effectiveness for each program. DSManager calculated cost-effectiveness using all five of the perspectives that are defined by the California Standard Practice. For this study, the TRC and RIM perspectives were used.

- The TRC benefits include the avoided capacity or demand and energy or production costs. TRC costs include administrative costs and incremental DSM technology costs .

- The RIM benefits include the avoided capacity or demand and energy or production costs and increases in revenue to the utility. RIM costs include administrative costs, rebates, and decreases in revenue to the utility.

Table 5-1 lists the complete results of the cost-effectiveness analysis as follows: program number, description of the DSM technology included in the program, and the resulting TRC and RIM benefit/cost ratios.

TABLE 5-1
BIG RIVERS CENTRALIZED
DETAILED COST-EFFECTIVENESS RESULTS

Program #	Description	TRC Score	RIM Score
1	R-11 Water Heater Tank Wrap	1.38	0.29
2	2.3 gpm Low-flow Showerhead and 2 Faucet Aerators	1.11	0.28
3	Programmable Thermostat-Electric Furnace	2.02	1.09
4	Upgrade Electric Furnace to 7.5 HSPF Air Source Heat Pump	0.62	0.44

TABLE 5-1 BIG RIVERS CENTRALIZED DETAILED COST-EFFECTIVENESS RESULTS			
Program #	Description	TRC Score	RIM Score
5	Water Heating Heat Traps	2.45	0.63
6	20 Feet R-5 Pipe Wrap Insulation	0.30	0.24
7	Replace Non-electric Heating System with Ground Source Heat Pump EER=13	n/a	1.03
8	Replace Non-electric Heating System with Air Source Heat Pump HSPF=7.5	n/a	3.63
9	Replace Non-electric Water Heater with Efficient Water Heater EF=.92	n/a	3.38
10	Replace Non-electric Water Heater with Efficient Water Heater EF=.92	n/a	3.70
11	Replace Non-electric Heating System with Unitary Packaged Air Source Heat Pump	n/a	1.06

PROGRAM RECOMMENDATIONS

For this study, program recommendations were made based on the resulting benefit/cost ratios for both the TRC and the RIM perspectives.

TRC PROGRAMS

Four of the programs analyzed passed the TRC test, i.e. the benefit/cost ratio from the total resource perspective was greater than or equal to 1.0. Descriptions of each of the programs are presented below.

PROGRAM 1 - RESIDENTIAL - ELECTRIC WATER HEATER TANK WRAP

The residential electric water heater tank wrap program offers cash rebates to residential customers who purchase and install a water heater tank wrap with a minimum insulation value of R-11 to their electric water heater. Rebates are set at fifty percent of the cost of the tank wrap.

PROGRAM 2 - RESIDENTIAL - LOW-FLOW SHOWERHEADS AND FITTINGS

The residential low-flow showerheads and fittings program offers cash rebates to residential customers with electric water heaters who purchase and install one low-flow showerhead, 2.3 gpm or less, and 2 faucet aerators. Rebates are set at fifty percent of the cost of the showerhead and faucet aerators.

PROGRAM 3 - RESIDENTIAL - SETBACK/CLOCK THERMOSTATS

The residential setback/clock thermostats offers cash rebates to residential customers with electric furnaces who purchase and install a programmable thermostat. Rebates are set at fifty percent of the cost of the programmable thermostat.

PROGRAM 5 - RESIDENTIAL - HEAT TRAPS

The residential heat traps program offers cash rebates to residential customers who purchase and install heat traps to their electric water heater inlet and outlet water connections. Rebates are set at fifty percent of the cost of the heat traps.

RIM PROGRAMS

Six of the programs analyzed passed the RIM test, i.e. the benefit/cost ratio from the ratepayer impact perspective was greater than or equal to 1.0. Descriptions of each of the programs are presented below.

PROGRAM 3 - RESIDENTIAL - SETBACK/CLOCK THERMOSTATS

The residential setback/clock thermostats offers cash rebates to residential customers with electric furnaces who purchase and install a programmable thermostat. Rebates are set at fifty percent of the cost of the programmable thermostat.

PROGRAM 7 - RESIDENTIAL - GROUND SOURCE HEAT PUMP REPLACEMENT

The residential ground source heat pump replacement program offers cash rebates to residential customers with non-electric heating systems who purchase and install a ground source heat pump with a minimum EER=13. Rebates are set at fifty percent of the incremental cost of the ground source heat pump as compared to a natural gas furnace and standard central air conditioner.

PROGRAM 8 - RESIDENTIAL - AIR SOURCE HEAT PUMP REPLACEMENT

The residential air source heat pump replacement program offers cash rebates to residential customers with non-electric heating systems who purchase and install an air source heat pump with a minimum HSPF=7.5/SEER=12. Rebates are set at $100.00 per heat pump.

PROGRAM 9 - RESIDENTIAL - ELECTRIC WATER HEATER REPLACEMENT

The residential electric water heater replacement program offers cash rebates to residential customers with non-electric water heaters who purchase and install an efficient electric water heater a minimum EF=.92. Rebates are set at $50.00 per water heater.

PROGRAM 10 - COMMERCIAL - ELECTRIC WATER HEATER REPLACEMENT

The commercial electric water heater replacement program offers cash rebates to commercial customers with non-electric water heaters who purchase and install an efficient electric water heater a minimum EF=.92. Rebates are set at $50.00 per water heater.

PROGRAM 11 - COMMERCIAL - AIR SOURCE HEAT PUMP REPLACEMENT

The commercial air source heat pump replacement program offers cash rebates to commercial customers with non-electric heating systems who purchase and install an efficient unitary packaged air source heat pump with a minimum COP=3.2. Rebates are set at $100.00 per 1000 square feet of building space conditioned.

Table 5-2 presents a cost-effectiveness summary of the eleven programs analyzed including program benefits and programs costs for both the TRC and the RIM perspectives.

TABLE 5-2 BIG RIVERS CENTRALIZED COST-EFFECTIVENESS SUMMARY ($1994)						
	TOTAL RESOURCE COST			RATEPAYER IMPACT MEASURE		
Program	Program Benefits	Program Costs	Net Benefits	Program Benefits	Program Costs	Net Benefits
Residential						
Elect Water Heater Tank Wrap	398,380	287,710	110,670	398,380	1,385,620	(987,240)
Low-flow Showerheads	460,630	386,910	43,720	430,630	1,559,690	(1,129,050)
Setback/Clock Thermostat	1,989,880	984,700	1,005,180	1,989,880	1,823,120	166,760
Heat Pump Conv Upgrade	3,832,930	6,193,330	(2,360,400)	3,832,930	8,755,340	(4,922,400)
Heat Traps	316,460	128,970	187,490	316,460	1,118,250	(801,790)
Water Heater Pipe Wrap	86,130	288,890	(202,770)	86,130	361,900	(275,780)
Heat Pump Grd Srce Replace	n/a	n/a	n/a	5,686,480	5,499,620	186,860
Heat Pump Conv Replace	n/a	n/a	n/a	13,020,280	3,584,610	9,436,670
Electric Water Heater Replace	n/a	n/a	n/a	3,680,910	1,089,220	2,591,700
Commercial						
Water Heater Replacement	n/a	n/a	n/a	84,410	22,820	61,600
Air Source Heat Pump Replce	n/a	n/a	n/a	157,760	149,060	8,700

Appendix B contains the Power Supplier Summary Report and the Power Supplier Benefit/Cost Matrix created by DSManager for each of the eleven programs.

6

COMPARISON OF RESULTS

The results of the individual company approach and the results of the Big Rivers Centralized approach were compared using the TRC and RIM perspectives for the Big Rivers system.

PROGRAM RESULTS

For each of the nine recommended programs listed in Section 5, Table 6-1 displays the TRC benefit/cost scores, and the RIM benefit/cost scores from the Big Rivers perspective and from the Coops perspective collectively. [Note: the "distribution cooperatives collectively" does not imply that the results for the RIM benefit/cost test for each individual cooperative are similar.]

TABLE 6-1
BIG RIVERS CENTRALIZED
BENEFIT/COST SCORES

Program #	Program	TRC Score	RIM Score	RIM Score
	Residential		[1]	[2]
1	Electric Water Heater Tank Wrap	1.38	0.29	0.58
2	Low-flow Showerheads and Fittings	1.11	0.28	0.60
3	Setback/Clock Thermostat	2.02	1.09	0.13
5	Heat Traps	2.45	0.28	0.63
7	Heat Pump Ground Source Replace	n/a	1.03	1.10
8	Heat Pump Conventional - Replace	n/a	3.63	0.99
9	Electric Water Heater - Replace	n/a	3.38	1.42
	Commercial			
10	Electric Water Heater - Replace	n/a	3.70	1.78
11	Air Source Heat Pump - Replace	n/a	1.06	0.75

[1] Big Rivers system
[2] Distribution cooperatives collectively

PLAN RESULTS

To compare the effects of implementation of the two study approaches, DSM plans were created. The DSManager program will provide aggregated results of individual programs to provide the results of a comprehensive DSM plan. Using this feature, the Big Rivers Centralized study recommended programs were aggregated into the following DSM plans: recommended TRC programs and recommended RIM programs. In addition, the individual company results for the four Coops were aggregated into two comprehensive DSM plans; recommended TRC programs and recommended RIM programs. Table 6-2 presents a comparison of the total costs and savings for the study period, 1994-2007, in 1994 dollars for the Big Rivers system for each of the DSM plans.

TABLE 6-2
BIG RIVERS CENTRALIZED
DSM PLAN RESULTS
($000)

	Total Resource Cost Perspective				Ratepayer Impact Measure Perspective			
Plan	B/C Ratio	Plan Benefts	Plan Costs	Net Benefits	B/C Ratio	Plan Benefits	Plan Costs	Net Benefits
Centralized Plans								
TRC	1.75	3,135	1,788	1,347	0.53	3,135	5,887	(2,751)
RIM	n/a	n/a	n/a	n/a	2.45	21,040	8,588	12,452
Individual Company Plans								
TRC	0.55	4,533	8,188	(3,655)	0.22	4,533	20,316	(15,783)
RIM	n/a	n/a	n/a	n/a	0.00	0	4,884	(4,884)

7

CONCLUSIONS AND RECOMMENDATIONS

Based on the results presented in the previous sections, this section presents several conclusions and recommendations.

CONCLUSIONS

Based on the analyses performed in the preceding sections the following conclusions have been reached:

- The air source heat pump program, electric to electric installations, at current participation levels is cost-effective for Big Rivers from the TRC perspective under the Big Rivers Centralized approach.

?

- The air source heat pump, electric water heater, and geothermal programs, electric to electric installations, at current participation levels are not cost-effective for Big Rivers from the TRC or the RIM perspective under the Big Rivers Centralized approach.
- The air source heat pump and electric water heater programs, conversion to electric installations, at current participation levels are cost-effective for Big Rivers from the RIM perspective under the Big Rivers Centralized approach.
- The geothermal program, conversion to electric installations, at current participation levels, is not cost-effective for Big Rivers from the RIM perspective under the Big Rivers Centralized approach.
- The All Seasons Comfort Home Program, at current participation levels, is not cost-effective for Big Rivers from the TRC or the RIM perspective under the Big Rivers Centralized approach.
- For the twenty-five programs recommended from the TRC perspective in the individual company approach, six programs are cost-effective from the TRC perspective under the Big Rivers Centralized approach.
- For the fourteen programs recommended from the RIM perspective in the individual company approach, ten programs are cost-effective from the RIM perspective under the Big Rivers Centralized approach.

- Based on the results of the individual company approach and the two preceding conclusions, eleven centralized DSM programs were developed.

- Four of the eleven centralized programs developed were cost-effective from the TRC perspective for Big Rivers under the Big Rivers Centralized approach.

- Six of the eleven centralized programs developed were cost-effective from the RIM perspective for Big Rivers under the Big Rivers Centralized approach.

- Of the six RIM cost-effective programs, three of the programs are cost-effective from the RIM perspective for the distribution cooperatives taken collectively.

- Neither the RIM or TRC aggregate DSM plans for the individual company approach are cost-effective for Big Rivers under the Big Rivers Centralized approach.

RECOMMENDATIONS

The following recommendations are presented based on the analyses and conclusions presented in this study:

- The current wholesale rate structure does not provide accurate pricing signals based on Big Rivers current capacity situation. The current wholesale rate needs to be changed to accurately reflect Big Rivers current capacity situation and in turn to identify the appropriate DSM efforts to be undertaken by Big Rivers and the distribution cooperatives.

- The current design of the All Seasons Comfort Home program is not cost-effective from the TRC or the RIM perspective for Big Rivers or the distribution cooperatives and based on these results should be discontinued.

- The least-cost approach, given the current wholesale rate, is the Big Rivers Centralized approach. If the individual company results are implemented by the distribution cooperatives, based on the results presented, the cost to Big Rivers in terms of revenue reduction could range from approximately five million dollars to sixteen million dollars (1994 dollars) over the study period, depending on the programs implemented.

- If the Big Rivers Centralized RIM recommended programs are selected for implementation, for each of the six programs recommended, a joint marketing decision should be made to determine appropriate rebate levels and program designs. Rebate levels for this study for the electric water heater and air source heat pump replacement programs were set at minimum levels based on the minimal incremental costs incurred by the participants. If rebate levels are increased, a subsequent cost-effectiveness analysis should be performed to determine if the program is still cost-effective at the higher rebate level.

- Based on the current wholesale rate situation, very few programs are cost-effective from all five companies perspectives. Although a program is cost-effective for Big Rivers from the Big Rivers Centralized approach and for the distribution cooperatives collectively, this occurs with some programs because one or two of the companies experiences a substantial increase in costs due to the impacts of a program which is not cost-effective. This is due in most cases to increased demand charges resulting from a switch from summer to winter peaking. Based on Big Rivers current capacity situation and production costs, programs should not derive a benefit based on capacity or demand. If the wholesale rate provided accurate price signals, programs would only be cost effective from the TRC perspective if the avoided production (energy) costs exceeded the costs of administering the program plus the incremental cost of the DSM technology and from the RIM perspective if the increase in energy charges paid by the distribution cooperatives exceeded the increase in production costs plus the rebates and administrative costs incurred by Big Rivers. Therefore, the analyses performed provide internally inconsistent results due to the current wholesale rate structure. It is recommended that until the wholesale rate is corrected, DSM programs should be implemented only if they are consistent with the discussion presented above.

- Information regarding the commercial and small industrial customers is very limited and more information should be obtained before programs are designed for these sectors. The information used in this study for the commercial/industrial sectors was based on national averages and limited utility specific data. It is recommended that a database of commercial and industrial customers be developed to include information regarding market segment classification, square footage, electric end-uses, end-use usage or intensity, etc. Once this information is available, subsequent evaluations of the commercial/industrial programs should be performed to determine whether these programs should be designed for implementation.

BIG RIVERS

A

BIG RIVERS CENTRALIZED DEMAND SIDE MANAGEMENT EXPECTATIONS

1 Address DSM as a group vs. G&T or distribution.

BIG RIVERS CENTRALIZED
DEMAND SIDE MANAGEMENT GOALS

Priority	Goals

1	Develop a long-term and a short-term DSM program that properly balances:
	- Big Rivers revenue regulations.
	- Include district coop. expenditures for DSM projects to benefit customers.
	  - Smelter
	  - Industrial
	  - Rural

2	Look at DSM from customers benefit ($).
3	Survival.
3	DSM aspect of competition.
4	Time table - do we need DSM now?
5	Same playing field so that all are on the same wavelength to avoid conflicting strategies.
6	Consumer friendly - ease of use.
7	Base analysis on overall Big Rivers cost.
8	Establish a revenue neutral DSM program.
9	Develop plan to get to long-term plan.
10	What is DSM?

BIG RIVERS CENTRALIZED DEMAND SIDE MANAGEMENT STRENGTHS

Priority	Strengths
1	Distribution coop. customer acceptance/credibility.
2	Distribution systems recognize change is necessary.
2	Technical migration plan.
3	Capacity.
4	Employee capability and skill levels.
4	Overall generative cost.
5	Programs in place.
6	Reliability.
7	Large industrial load base.
8	Unity.
9	Geographic location.
10	Rates.

BIG RIVERS CENTRALIZED
DEMAND SIDE MANAGEMENT WEAKNESSES

Priority	Weaknesses
1	Lack of commitment on G&T part.
2	Distribution coop. wholesale power rate.
3	Different agendas.
4	Public perception.
4	Employees staffing levels and skills.
5	No coordinated DSM plan.
5	Too much debt on all organization.
6	Capacity.
7	High load factor.

BIG RIVERS CENTRALIZED DEMAND SIDE MANAGEMENT OPPORTUNITIES

Priority	Opportunities
1	Develop a coordinated plan based on unity of purpose.
2	Positive impact financially on customer.
3	Meeting consumers needs.
4	Improve image.
5	Tools on means to educate membership.
6	Diversify the load mix.

BIG RIVERS CENTRALIZED
DEMAND SIDE MANAGEMENT THREATS

Priority	Threats
1	Locked into plan that is difficult to change.
2	Retail wheeling.
3	Make a capital investment based on existing wholesale rates and DSM strategy and rate changes.
4	Development of conflicting or inconsistent plans.
5	Loss of existing or future load.
6	Customer acceptance.
7	Not complying with PSC regulations.
8	Hostile environment smelters.
9	PSC rate base approved.
10	Program failures.
10	Impact of clean air act.
10	Unfriendly consolidation.
11	New technologies.
11	High wholesale rate strategies.

BIG RIVERS CENTRALIZED
DEMAND SIDE MANAGEMENT STRATEGIES & TACTICS

Priority	Strategies & Tactics
1	Determine what consumer wants.
2	Develop a perspective for DSM evaluation.
3	Implement short-term and plan long-term.
4	Explain a wholesale rate that reflects cost (as it relates to DSM).
5	Maintain high public profile.
5	Develop evaluation process for specific issues.
6	Cost justify individual DSM projects.
7	Explore retail rate that reflects cost (as it relates to DSM).
8	Employee and board and consumer training.
8	Monitor, evaluate, measure results and resource requirements.
8	Coordinate: - PRS - Financial forecast - Generation plan - DSM
9	Obtain regulatory approval.
10	Update DSM issues at a minimum of every two years.

B

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG1 - Centralized Study Program 1

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_WRP	Res-Green River-Wtr Heat-Tank Wrap
1994	2007	R_HU_WRP	Res-Henderson Union-Wtr Heat-Tank Wrap
1994	2007	R_JP_WRP	Res-Jackson Purchase-Wtr Heat-Tank Wrap
1994	2007	R_MC_WRP	Res-Meade Cty-Water Heating-Tank Wrap

EPRI DSManager

Page: 1
Date:03/31/95
Time:08:39:03

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG1 - Centralized Study Program 1

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	18.14	0.00	6.68	0.00	0.00
1996	57.71	0.00	20.50	0.00	0.00
1997	117.99	0.00	39.86	0.00	0.00
1998	179.48	0.00	56.77	0.00	0.00
1999	242.20	0.00	76.22	0.00	0.00
2000	244.63	0.00	78.11	0.00	0.00
2001	247.07	0.00	76.09	0.00	0.00
2002	249.54	0.00	74.52	0.00	0.00
2003	252.04	0.00	72.18	0.00	0.00
2004	254.56	0.00	71.03	0.00	0.00
2005	237.07	0.00	63.04	0.00	0.00
2006	195.93	0.00	50.94	0.00	0.00
2007	131.94	0.00	32.94	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG1 - Centralized Study Program 1

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	1.51	0.00	6.28	0.00	0.00	0.00	0.00
1996	2.15	0.00	13.51	0.00	0.00	0.00	0.00
1997	1.63	0.00	20.26	0.00	0.00	0.00	0.00
1998	1.63	0.00	20.27	0.00	0.00	0.00	0.00
1999	1.63	0.00	20.27	0.00	0.00	0.00	0.00
2000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2001	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2002	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2003	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2004	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2005	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG1 - Centralized Study Program 1

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(14.47)	(14.47)	(19.25)	(19.25)	551.07	0.07
1996	(36.16)	(50.64)	(52.88)	(72.13)	1,735.90	0.21
1997	(61.75)	(112.39)	(100.02)	(172.15)	3,513.69	0.43
1998	(78.67)	(191.06)	(144.61)	(316.76)	5,292.03	0.64
1999	(98.12)	(289.18)	(187.90)	(504.66)	7,070.91	0.86
2000	(78.11)	(367.29)	(166.51)	(671.17)	7,070.91	0.86
2001	(76.09)	(443.38)	(170.98)	(842.15)	7,070.91	0.86
2002	(74.52)	(517.90)	(175.03)	(1,017.18)	7,070.91	0.86
2003	(72.18)	(590.08)	(179.86)	(1,197.04)	7,070.91	0.86
2004	(71.03)	(661.11)	(183.53)	(1,380.57)	7,070.92	0.86
2005	(63.04)	(724.15)	(174.02)	(1,554.59)	6,519.84	0.79
2006	(50.94)	(775.09)	(144.99)	(1,699.58)	5,335.01	0.65
2007	(32.94)	(808.03)	(99.00)	(1,798.59)	3,557.22	0.43

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG1 - Centralized Study Program 1

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Inc.							
	Cust. Nonelec. Bill Inc.	0.00						
	Cust. O&M Cost Inc.	0.00					0.00	0.00
	Cust. Cap. Invest. Inc.	264.54					220.33	238.07
	Cust. Other Costs Inc.	0.00					0.00	0.00
	Cust. Rebates Paid							
	Cust. Income Tax Inc.							
	DS Revenue Dec.				2,547.97			
	DS Elec. Acq. Cost Inc.							
C	DS Nonelec. Revenue Dec.				0.00			
	DS Nonelec. Acq. Cost Inc.		0.00		0.00			
O	DS Rebates Paid		66.16		66.16			
	DS Cap. Rebates Paid		0.00		0.00			
S	DS Admin. Cost Inc.		64.75		64.75		60.62	64.75
	DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
T	DS Sales Tax Cost Inc.		0.00		0.00		0.00	
	PS Revenue Dec.					1,317.62		
S	PS Elec. Prod. Cost Inc.							
	PS Nonelec. Revenue Dec.							
	PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
	PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
	PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
	PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
	PS Rebates Paid			61.23		61.23		
	PS Cap. Rebates Paid			0.00		0.00		
	PS Admin. Cost Inc.			6.77		6.77	6.77	7.23
	PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
	Nonelec. Acq. Cost Inc.						0.00	0.00
	Internal Environmental Cost							
	External Environmental Cost							

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG1 - Centralized Study Program 1

PERSPECTIVES Data discounted to 1994	PARTICIPANT TEST ('000 $)	DS UTILITY TEST ('000 $)	PS UTILITY TEST ('000 $)	DS RATEPAYER IMPACT TEST ('000 $)	PS RATEPAYER IMPACT TEST ('000 $)	TOTAL RESOURCE TEST ('000 $)	SOCIETAL TEST ('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Dec.	2,831.29						
Cust. Nonelec. Bill Dec.							
Cust. O&M Cost Dec.							
Cust. Cap. Invest. Dec.							
Cust. Other Costs Dec.							
Cust. Income Tax Dec.	0.00					0.00	
Cust. Rebates Rec'ved	132.33						
DS Revenue Inc.							
DS Elec. Acq. Cost Dec.		1,559.47		1,559.47			
DS Nonelec. Revenue Dec.							
DS Nonelec. Acq. Cost Dec.							
DS Rebates Rec'ved							
DS Cap. Rebates Rec'ved							
DS Admin. Cost Dec.							
DS Cap. Admin. Cost Dec.							
DS Sales Tax Cost Dec.							
PS Revenue Inc.							
PS Elec. Prod. Cost Dec.			398.38		398.38	398.38	468.71
PS Nonelec. Revenue Inc.					0.00		
PS Nonelec. Acq. Cost Dec.							
PS Gen. Cap. Credit							
PS Trans. Cap. Credit							
PS Dist. Cap. Credit							
PS Rebates Rec'ved							
PS Cap. Rebates Rec'ved							
PS Admin. Cost Dec.							
PS Cap. Admin. Cost Dec.							
Nonelec. Acq. Cost Dec.							
Internal Environmental Ben.			0.00		0.00	0.00	0.00
External Environmental Ben.							46.87
Total Costs	264.54	130.91	68.00	2,678.89	1,385.62	287.71	310.05
Total Benefits	2,963.62	1,559.47	398.38	1,559.47	398.38	398.38	515.58
Net Benefits	2,699.08	1,428.56	330.38	(1,119.42)	(987.24)	110.67	205.53
Levelized Costs	28.46	14.08	8.49	288.21	172.98	35.92	33.36
Levelized Benefits	318.84	167.78	49.74	167.78	49.74	49.74	55.47
Levelized Costs ($/kWh)	5.9444	0.0029	0.0018	0.0602	0.0368	0.0076	0.0082
Levelized Benefits ($/kWh)	66.5958	0.0350	0.0106	0.0350	0.0106	0.0106	0.0137
Levelized Costs ($/kW)	49,065.92	24.28	14.90	496.88	303.54	63.03	67.92
Levelized Benefits ($/kW)	549,689.41	289.25	87.27	289.25	87.27	87.27	112.94
Benefit/Cost Ratio	11.20	11.91	5.86	0.58	0.29	1.38	1.66

EPRI DSManager

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG2 - Centralized Study Program 2

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_SHW	Res-Green River-Wtr Heat-Showerheads/Fit
1994	2007	R_HU_SHW	Res-Henderson Union-WH-Showerheads/Fit
1994	2007	R_JP_SHW	Res-Jackson Purchase-WH-Showerheads/Fitt
1994	2007	R_MC_SHW	Res-Meade Cty-Wtr Heat-Showerheads/Fitt

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG2 - Centralized Study Program 2

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	20.12	0.00	7.23	0.00	0.00
1996	64.00	0.00	22.17	0.00	0.00
1997	132.20	0.00	42.85	0.00	0.00
1998	201.10	0.00	60.70	0.00	0.00
1999	271.39	0.00	81.70	0.00	0.00
2000	271.29	0.00	84.81	0.00	0.00
2001	274.00	0.00	82.41	0.00	0.00
2002	276.74	0.00	80.93	0.00	0.00
2003	282.41	0.00	77.92	0.00	0.00
2004	285.24	0.00	76.82	0.00	0.00
2005	262.90	0.00	68.84	0.00	0.00
2006	217.28	0.00	55.73	0.00	0.00
2007	146.32	0.00	35.85	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG2 - Centralized Study Program 2

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	2.03	0.00	8.44	0.00	0.00	0.00	0.00
1996	2.91	0.00	18.16	0.00	0.00	0.00	0.00
1997	2.18	0.00	27.23	0.00	0.00	0.00	0.00
1998	2.18	0.00	27.24	0.00	0.00	0.00	0.00
1999	2.18	0.00	27.25	0.00	0.00	0.00	0.00
2000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2001	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2002	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2003	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2004	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2005	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG2 - Centralized Study Program 2

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(17.70)	(17.70)	(23.36)	(23.36)	584.57	0.09
1996	(43.23)	(60.93)	(62.90)	(86.26)	1,841.41	0.28
1997	(72.26)	(133.19)	(118.76)	(205.02)	3,727.26	0.56
1998	(90.12)	(223.31)	(169.82)	(374.84)	5,613.69	0.84
1999	(111.13)	(334.44)	(219.12)	(593.96)	7,500.70	1.13
2000	(84.81)	(419.25)	(186.48)	(780.44)	7,500.70	1.13
2001	(82.41)	(501.66)	(191.59)	(972.03)	7,500.70	1.13
2002	(80.93)	(582.59)	(195.81)	(1,167.84)	7,500.70	1.13
2003	(77.92)	(660.50)	(204.49)	(1,372.33)	7,500.70	1.13
2004	(76.82)	(737.33)	(208.41)	(1,580.75)	7,500.70	1.13
2005	(68.84)	(806.17)	(194.06)	(1,774.81)	6,916.13	1.04
2006	(55.73)	(861.90)	(161.55)	(1,936.35)	5,659.29	0.85
2007	(35.85)	(897.75)	(110.47)	(2,046.82)	3,773.44	0.57

Big Rivers Electric Corporation
Time:08:39:33

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG2 - Centralized Study Program 2

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Inc.							
	Cust. Nonelec. Bill Inc.	0.00						
	Cust. O&M Cost Inc.	0.00					0.00	0.00
	Cust. Cap. Invest. Inc.	355.72					296.27	320.13
	Cust. Other Costs Inc.	0.00					0.00	0.00
	Cust. Rebates Paid							
	Cust. Income Tax Inc.							
	DS Revenue Dec.				2,696.28			
	DS Elec. Acq. Cost Inc.							
C	DS Nonelec. Revenue Dec.				0.00			
	DS Nonelec. Acq. Cost Inc.		0.00		0.00			
O	DS Rebates Paid		88.93		88.93			
	DS Cap. Rebates Paid		0.00		0.00			
S	DS Admin. Cost Inc.		87.14		87.14		81.57	87.14
	DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
T	DS Sales Tax Cost Inc.		0.00		0.00		0.00	
	PS Revenue Dec.					1,468.32		
S	PS Elec. Prod. Cost Inc.							
	PS Nonelec. Revenue Dec.							
	PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
	PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
	PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
	PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
	PS Rebates Paid			82.30		82.30		
	PS Cap. Rebates Paid			0.00		0.00		
	PS Admin. Cost Inc.			9.06		9.06	9.06	9.68
	PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
	Nonelec. Acq. Cost Inc.						0.00	0.00
	Internal Environmental Cost							
	External Environmental Cost							

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG2 - Centralized Study Program 2

	PERSPECTIVES Data discounted to 1994	PARTICIPANT TEST ('000 $)	DS UTILITY TEST ('000 $)	PS UTILITY TEST ('000 $)	DS RATEPAYER IMPACT TEST ('000 $)	PS RATEPAYER IMPACT TEST ('000 $)	TOTAL RESOURCE TEST ('000 $)	SOCIETAL TEST ('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.	2,996.09						
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	177.86						
B	DS Revenue Inc.							
	DS Elec. Acq. Cost Dec.		1,737.64		1,737.64			
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.							
I	PS Elec. Prod. Cost Dec.			430.63		430.63	430.63	506.81
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							50.6[illegible]
	Total Costs	355.72	176.07	91.37	2,872.35	1,559.69	386.91	416.94
	Total Benefits	3,173.95	1,737.64	430.63	1,737.64	430.63	430.63	557.50
	Net Benefits	2,818.23	1,561.57	339.27	(1,134.71)	(1,129.05)	43.72	140.55
	Levelized Costs	38.27	18.94	11.41	309.02	194.71	48.30	44.86
	Levelized Benefits	341.47	186.94	53.76	186.94	53.76	53.76	59.98
	Levelized Costs ($/kWh)	7.5354	0.0037	0.0023	0.0608	0.0390	0.0097	0.0104
	Levelized Benefits ($/kWh)	67.2355	0.0368	0.0108	0.0368	0.0108	0.0108	0.0139
	Levelized Costs ($/kW)	50,110.10	24.80	15.20	404.63	259.50	64.37	69.37
	Levelized Benefits ($/kW)	447,114.47	244.78	71.65	244.78	71.65	71.65	92.75
	Benefit/Cost Ratio	8.92	9.87	4.71	0.60	0.28	1.11	1.34

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG3 - Centralized Study Program 3

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_SCT	Res-Green River-Spc Cnd-Setback Thermost
1994	2007	R_HU_SCT	Res-Hend Union-Spc Cnd-Setback Thermosta
1994	2007	R_JP_SCT	Res-Jackson Purchase-Spc Cnd-Setback Th
1994	2007	R_MC_SCT	Res-Meade Cty-Space Con-Setback Therm.

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG3 - Centralized Study Program 3

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	45.92	0.00	31.55	0.00	0.00
1996	146.25	0.00	98.10	0.00	0.00
1997	350.03	0.00	194.75	0.00	0.00
1998	363.17	0.00	281.47	0.00	0.00
1999	274.86	0.00	376.79	0.00	0.00
2000	151.09	0.00	365.71	0.00	0.00
2001	152.60	0.00	355.12	0.00	0.00
2002	154.13	0.00	351.23	0.00	0.00
2003	286.02	0.00	342.69	0.00	0.00
2004	238.88	0.00	336.23	0.00	0.00
2005	158.80	0.00	315.91	0.00	0.00
2006	160.38	0.00	310.73	0.00	0.00
2007	161.99	0.00	303.17	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG3 - Centralized Study Program 3

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	5.13	0.00	21.40	0.00	0.00	0.00	0.00
1996	7.40	0.00	46.23	0.00	0.00	0.00	0.00
1997	5.55	0.00	69.36	0.00	0.00	0.00	0.00
1998	5.55	0.00	69.36	0.00	0.00	0.00	0.00
1999	5.55	0.00	69.36	0.00	0.00	0.00	0.00
2000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2001	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2002	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2003	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2004	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2005	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG3 - Centralized Study Program 3

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(58.08)	(58.08)	(40.89)	(40.89)	2,768.37	0.05
1996	(151.73)	(209.81)	(101.77)	(142.66)	8,763.63	0.15
1997	(269.65)	(479.46)	(230.19)	(372.86)	17,754.92	0.30
1998	(356.37)	(835.83)	(156.60)	(529.46)	26,748.25	0.45
1999	(451.70)	(1,287.53)	27.03	(502.43)	35,741.61	0.58
2000	(365.71)	(1,653.24)	214.62	(287.81)	35,741.61	0.58
2001	(355.12)	(2,008.36)	202.52	(85.29)	35,741.61	0.58
2002	(351.23)	(2,359.59)	197.10	111.82	35,741.61	0.58
2003	(342.69)	(2,702.28)	56.67	168.49	35,741.61	0.58
2004	(336.23)	(3,038.51)	47.35	215.83	35,741.61	0.58
2005	(315.91)	(3,354.42)	157.12	372.95	35,741.61	0.58
2006	(310.73)	(3,665.15)	150.34	523.29	35,741.61	0.58
2007	(303.17)	(3,968.32)	141.19	664.48	35,741.61	0.58

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG3 - Centralized Study Program 3

PERSPECTIVES Data discounted to 1994	PARTICIPANT TEST ('000 $)	DS UTILITY TEST ('000 $)	PS UTILITY TEST ('000 $)	DS RATEPAYER IMPACT TEST ('000 $)	PS RATEPAYER IMPACT TEST ('000 $)	TOTAL RESOURCE TEST ('000 $)	SOCIETAL TEST ('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Inc.							
Cust. Nonelec. Bill Inc.	0.00						
Cust. O&M Cost Inc.	0.00					0.00	0.00
Cust. Cap. Invest. Inc.	905.28					754.17	814.89
Cust. Other Costs Inc.	0.00					0.00	0.00
Cust. Rebates Paid							
Cust. Income Tax Inc.							
DS Revenue Dec.				13,369.75			
DS Elec. Acq. Cost Inc.							
DS Nonelec. Revenue Dec.				0.00			
DS Nonelec. Acq. Cost Inc.		0.00		0.00			
DS Rebates Paid		226.32		226.32			
DS Cap. Rebates Paid		0.00		0.00			
DS Admin. Cost Inc.		221.64		221.64		207.48	221.64
DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
DS Sales Tax Cost Inc.		0.00		0.00		0.00	
PS Revenue Dec.					1,590.61		
PS Elec. Prod. Cost Inc.							
PS Nonelec. Revenue Dec.							
PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
PS Rebates Paid			209.45		209.45		
PS Cap. Rebates Paid			0.00		0.00		
PS Admin. Cost Inc.			23.05		23.05	23.05	24.63
PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
Nonelec. Acq. Cost Inc.						0.00	0.00
Internal Environmental Cost							
External Environmental Cost							

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG3 - Centralized Study Program 3

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.	14,351.84						
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	452.64						
B	DS Revenue Inc.							
	DS Elec. Acq. Cost Dec.		1,835.04		1,835.04			
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.							
I	PS Elec. Prod. Cost Dec.			1,989.88		1,989.88	1,989.88	2,353.02
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							235.30
	Total Costs	905.28	447.96	232.51	13,817.71	1,823.12	984.70	1,061.15
	Total Benefits	15,304.48	1,835.04	1,989.88	1,835.04	1,989.88	1,989.88	2,588.32
	Net Benefits	14,399.20	1,387.08	1,757.37	(11,982.67)	166.76	1,005.18	1,527.17
	Levelized Costs	97.39	48.19	29.03	1,486.58	227.60	122.93	114.16
	Levelized Benefits	1,646.53	197.42	248.42	197.42	248.42	248.42	278.46
	Levelized Costs ($/kWh)	3.7867	0.0019	0.0012	0.0578	0.0091	0.0049	0.0053
	Levelized Benefits ($/kWh)	64.0177	0.0077	0.0099	0.0077	0.0099	0.0099	0.0129
	Levelized Costs ($/kW)	232,426.53	115.01	70.92	3,547.64	556.08	300.35	323.67
	Levelized Benefits ($/kW)	##.##	471.14	606.95	471.14	606.95	606.95	789.48
	Benefit/Cost Ratio	16.91	4.10	8.56	0.13	1.09	2.02	2.44

Meade County Rural Electric Coco Corp.

Demand-Side Management Plan

Plan: CEN_PRG4 - Centralized Study Program 4

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_UPR	Res-Green River-Spc Cnd-ASHP Upgrade (R)
1994	2007	R_HU_UPR	Res-Hend Union-Spc Cnd-ASHP Upgrade Res
1994	2007	R_JP_UPR	Res-Jackson-Spc Cnd-ASHP Upgrade (R)
1994	2007	R_MC_UPR	Res-Meade Cty-Space Cond-ASHP Upgrade Rs

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG4 - Centralized Study Program 4

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	119.99	0.00	71.36	0.00	0.00
1996	285.97	0.00	164.71	0.00	0.00
1997	336.58	0.00	255.13	0.00	0.00
1998	474.80	0.00	340.92	0.00	0.00
1999	615.82	0.00	436.35	0.00	0.00
2000	1,048.44	0.00	545.75	0.00	0.00
2001	1,248.95	0.00	622.99	0.00	0.00
2002	1,453.70	0.00	710.00	0.00	0.00
2003	1,208.56	0.00	769.38	0.00	0.00
2004	1,364.25	0.00	845.09	0.00	0.00
2005	2,092.75	0.00	902.02	0.00	0.00
2006	2,292.58	0.00	984.52	0.00	0.00
2007	2,493.47	0.00	1,024.08	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG4 - Centralized Study Program 4

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	10.16	0.00	127.06	0.00	0.00	0.00	0.00
1996	13.93	0.00	174.09	0.00	0.00	0.00	0.00
1997	15.41	0.00	192.61	0.00	0.00	0.00	0.00
1998	15.39	0.00	192.38	0.00	0.00	0.00	0.00
1999	15.41	0.00	192.61	0.00	0.00	0.00	0.00
2000	15.41	0.00	192.61	0.00	0.00	0.00	0.00
2001	15.43	0.00	192.85	0.00	0.00	0.00	0.00
2002	15.45	0.00	193.09	0.00	0.00	0.00	0.00
2003	15.45	0.00	193.09	0.00	0.00	0.00	0.00
2004	15.47	0.00	193.32	0.00	0.00	0.00	0.00
2005	15.48	0.00	193.56	0.00	0.00	0.00	0.00
2006	15.50	0.00	193.80	0.00	0.00	0.00	0.00
2007	15.52	0.00	194.04	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG4 - Centralized Study Program 4

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(208.59)	(208.59)	(185.85)	(185.85)	6,112.92	0.05
1996	(352.73)	(561.32)	(309.27)	(495.13)	14,453.49	0.12
1997	(463.16)	(1,024.47)	(289.46)	(784.59)	23,621.34	0.19
1998	(548.69)	(1,573.16)	(341.64)	(1,126.23)	32,777.40	0.26
1999	(644.37)	(2,217.54)	(387.49)	(1,513.73)	41,947.88	0.34
2000	(753.77)	(2,971.31)	(710.72)	(2,224.44)	51,118.44	0.41
2001	(831.27)	(3,802.58)	(834.24)	(3,058.68)	60,303.40	0.48
2002	(918.53)	(4,721.11)	(952.24)	(4,010.93)	69,502.86	0.56
2003	(977.92)	(5,699.03)	(647.71)	(4,658.64)	78,699.68	0.63
2004	(1,053.88)	(6,752.90)	(727.95)	(5,386.59)	87,911.00	0.70
2005	(1,111.07)	(7,863.97)	(1,399.78)	(6,786.37)	97,136.72	0.78
2006	(1,193.82)	(9,057.79)	(1,517.37)	(8,303.74)	106,376.94	0.85
2007	(1,233.64)	(10,291.43)	(1,678.95)	(9,982.69)	115,629.01	0.92

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG4 - Centralized Study Program 4

PERSPECTIVES Data discounted to 1994	PARTICIPANT TEST ('000 $)	DS UTILITY TEST ('000 $)	PS UTILITY TEST ('000 $)	DS RATEPAYER IMPACT TEST ('000 $)	PS RATEPAYER IMPACT TEST ('000 $)	TOTAL RESOURCE TEST ('000 $)	SOCIETAL TEST ('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Inc.							
Cust. Nonelec. Bill Inc.	0.00						
Cust. O&M Cost Inc.	0.00					0.00	0.00
Cust. Cap. Invest. Inc.	6,518.06					5,067.49	5,867.31
Cust. Other Costs Inc.	0.00					0.00	0.00
Cust. Rebates Paid							
Cust. Income Tax Inc.							
DS Revenue Dec.				25,579.85			
DS Elec. Acq. Cost Inc.							
DS Nonelec. Revenue Dec.				0.00			
DS Nonelec. Acq. Cost Inc.		0.00		0.00			
DS Rebates Paid		1,629.52		1,629.52			
DS Cap. Rebates Paid		0.00		0.00			
DS Admin. Cost Inc.		1,173.25		1,173.25		1,013.26	1,173.25
DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
DS Sales Tax Cost Inc.		0.00		0.00		0.00	
PS Revenue Dec.					7,235.45		
PS Elec. Prod. Cost Inc.							
PS Nonelec. Revenue Dec.							
PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
PS Rebates Paid			1,407.30		1,407.30		
PS Cap. Rebates Paid			0.00		0.00		
PS Admin. Cost Inc.			112.58		112.58	112.58	130.35
PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
Nonelec. Acq. Cost Inc.						0.00	0.00
Internal Environmental Cost							
External Environmental Cost							

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG4 - Centralized Study Program 4

PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Dec.	29,528.12						
Cust. Nonelec. Bill Dec.							
Cust. O&M Cost Dec.							
Cust. Cap. Invest. Dec.							
Cust. Other Costs Dec.							
Cust. Income Tax Dec.	0.00					0.00	
Cust. Rebates Rec'ved	3,259.03						
B DS Revenue Inc.							
DS Elec. Acq. Cost Dec.		8,856.33		8,856.33			
E DS Nonelec. Revenue Dec.							
DS Nonelec. Acq. Cost Dec.							
N DS Rebates Rec'ved							
DS Cap. Rebates Rec'ved							
E DS Admin. Cost Dec.							
DS Cap. Admin. Cost Dec.							
F DS Sales Tax Cost Dec.							
PS Revenue Inc.							
I PS Elec. Prod. Cost Dec.			3,832.93		3,832.93	3,832.93	4,640.63
PS Nonelec. Revenue Inc.					0.00		
T PS Nonelec. Acq. Cost Dec.							
PS Gen. Cap. Credit							
S PS Trans. Cap. Credit							
PS Dist. Cap. Credit							
PS Rebates Rec'ved							
PS Cap. Rebates Rec'ved							
PS Admin. Cost Dec.							
PS Cap. Admin. Cost Dec.							
Nonelec. Acq. Cost Dec.							
Internal Environmental Ben.			0.00		0.00	0.00	0.00
External Environmental Ben.							464.06
Total Costs	6,518.06	2,802.77	1,519.89	20,382.62	8,755.34	6,193.33	7,171.43
Total Benefits	32,787.15	8,856.33	3,832.93	8,856.33	3,832.93	3,832.93	5,104.69
Net Benefits	26,269.09	6,053.56	2,313.04	(11,526.28)	(4,922.40)	(2,360.40)	(2,066.74)
Levelized Costs	701.25	301.54	193.75	2,161.13	1,093.04	773.19	771.54
Levelized Benefits	3,527.40	952.81	478.51	952.81	478.51	478.51	549.19
Levelized Costs ($/kWh)	13.8848	0.0060	0.0039	0.0626	0.0227	0.0161	0.0186
Levelized Benefits ($/kWh)	69.8431	0.0189	0.0099	0.0189	0.0099	0.0099	0.0132
Levelized Costs ($/kW)	##.##	744.72	491.27	7,337.18	2,829.98	2,001.87	2,318.02
Levelized Benefits ($/kW)	##.##	2,353.19	1,238.92	2,353.19	1,238.92	1,238.92	1,649.99
Benefit/Cost Ratio	5.03	3.16	2.52	0.30	0.44	0.62	0.71

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG5 - Centralized Study Program 5

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_TRP	Res-Green River-Wtr Heating-Heat Traps
1994	2007	R_HU_TRP	Res-Henderson Union-Wtr Heat-Heat Traps
1994	2007	R_JP_TRP	Res-Jackson Purchase-Wtr Heat-Heat Traps
1994	2007	R_MC_TRP	Res-Meade Cty-Water Heating-Heat Traps

Power Supplier Summary Report

Plan: CEN_PRG5 - Centralized Study Program 5

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	14.08	0.00	5.06	0.00	0.00
1996	44.80	0.00	15.52	0.00	0.00
1997	92.54	0.00	29.99	0.00	0.00
1998	140.77	0.00	42.49	0.00	0.00
1999	189.97	0.00	57.19	0.00	0.00
2000	189.90	0.00	59.37	0.00	0.00
2001	191.80	0.00	57.69	0.00	0.00
2002	193.72	0.00	56.65	0.00	0.00
2003	197.69	0.00	54.54	0.00	0.00
2004	199.66	0.00	53.78	0.00	0.00
2005	199.59	0.00	52.26	0.00	0.00
2006	201.58	0.00	51.70	0.00	0.00
2007	203.60	0.00	49.89	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG5 - Centralized Study Program 5

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	0.68	0.00	2.82	0.00	0.00	0.00	0.00
1996	0.97	0.00	6.05	0.00	0.00	0.00	0.00
1997	0.73	0.00	9.08	0.00	0.00	0.00	0.00
1998	0.73	0.00	9.08	0.00	0.00	0.00	0.00
1999	0.73	0.00	9.08	0.00	0.00	0.00	0.00
2000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2001	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2002	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2003	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2004	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2005	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Plan: CEN_PRG5 - Centralized Study Program 5

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(8.55)	(8.55)	(12.51)	(12.51)	409.20	0.06
1996	(22.54)	(31.09)	(36.31)	(48.82)	1,288.99	0.19
1997	(39.80)	(70.89)	(72.35)	(121.17)	2,609.08	0.39
1998	(52.30)	(123.19)	(108.09)	(229.26)	3,929.58	0.59
1999	(67.00)	(190.18)	(142.59)	(371.85)	5,250.49	0.79
2000	(59.37)	(249.55)	(130.54)	(502.39)	5,250.49	0.79
2001	(57.69)	(307.24)	(134.11)	(636.50)	5,250.49	0.79
2002	(56.65)	(363.89)	(137.07)	(773.56)	5,250.49	0.79
2003	(54.54)	(418.43)	(143.15)	(916.71)	5,250.49	0.79
2004	(53.78)	(472.21)	(145.89)	(1,062.60)	5,250.49	0.79
2005	(52.26)	(524.47)	(147.32)	(1,209.92)	5,250.49	0.79
2006	(51.70)	(576.17)	(149.88)	(1,359.80)	5,250.49	0.79
2007	(49.89)	(626.06)	(153.71)	(1,513.52)	5,250.49	0.79

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG5 - Centralized Study Program 5

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Inc.							
	Cust. Nonelec. Bill Inc.	0.00						
	Cust. O&M Cost Inc.	0.00					0.00	0.00
	Cust. Cap. Invest. Inc.	118.57					98.76	106.71
	Cust. Other Costs Inc.	0.00					0.00	0.00
	Cust. Rebates Paid							
	Cust. Income Tax Inc.							
	DS Revenue Dec.				2,012.48			
	DS Elec. Acq. Cost Inc.							
C	DS Nonelec. Revenue Dec.				0.00			
	DS Nonelec. Acq. Cost Inc.		0.00		0.00			
O	DS Rebates Paid		29.64		29.64			
	DS Cap. Rebates Paid		0.00		0.00			
S	DS Admin. Cost Inc.		29.05		29.05		27.19	29.05
	DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
T	DS Sales Tax Cost Inc.		0.00		0.00		0.00	
	PS Revenue Dec.					1,087.79		
S	PS Elec. Prod. Cost Inc.							
	PS Nonelec. Revenue Dec.							
	PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
	PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
	PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
	PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
	PS Rebates Paid			27.43		27.43		
	PS Cap. Rebates Paid			0.00		0.00		
	PS Admin. Cost Inc.			3.02		3.02	3.02	3.23
	PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
	Nonelec. Acq. Cost Inc.						0.00	0.00
	Internal Environmental Cost							
	External Environmental Cost							

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG5 - Centralized Study Program 5

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.	2,236.28						
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	59.29						
B	DS Revenue Inc.							
	DS Elec. Acq. Cost Dec.		1,296.57		1,296.57			
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.							
I	PS Elec. Prod. Cost Dec.			316.46		316.46	316.46	374.85
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							37.48
	Total Costs	118.57	58.69	30.46	2,071.17	1,118.25	128.97	138.98
	Total Benefits	2,295.57	1,296.57	316.46	1,296.57	316.46	316.46	412.33
	Net Benefits	2,176.99	1,237.88	286.00	(774.59)	(801.79)	187.49	273.35
	Levelized Costs	12.76	6.31	3.80	222.83	139.60	16.10	14.95
	Levelized Benefits	246.97	139.49	39.51	139.49	39.51	39.51	44.36
	Levelized Costs ($/kWh)	3.3758	0.0017	0.0010	0.0590	0.0379	0.0044	0.0047
	Levelized Benefits ($/kWh)	65.3563	0.0369	0.0107	0.0369	0.0107	0.0107	0.0140
	Levelized Costs ($/kW)	22,449.36	11.11	6.86	392.13	251.80	29.04	31.29
	Levelized Benefits ($/kW)	434,619.12	245.48	71.26	245.48	71.26	71.26	92.85
	Benefit/Cost Ratio	19.36	22.09	10.39	0.63	0.28	2.45	2.97

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG6 - Centralized Study Program 6

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_PWR	Res-Green River-Wtr Heating-Pipe Wrap
1994	2007	R_HU_PWR	Res-Henderson Union-Wtr Heat-Pipe Wrap
1994	2007	R_JP_PWR	Res-Jackson Purchase-Wtr Heat-Pipe Wrap
1994	2007	R_MC_PWR	Res-Meade Cty-Wtr Heat-Pipe Wrap

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG6 - Centralized Study Program 6

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	4.02	0.00	1.45	0.00	0.00
1996	12.80	0.00	4.43	0.00	0.00
1997	25.44	0.00	8.57	0.00	0.00
1998	40.22	0.00	12.14	0.00	0.00
1999	54.28	0.00	16.34	0.00	0.00
2000	54.26	0.00	16.96	0.00	0.00
2001	54.80	0.00	16.48	0.00	0.00
2002	55.35	0.00	16.19	0.00	0.00
2003	56.48	0.00	15.58	0.00	0.00
2004	57.05	0.00	15.36	0.00	0.00
2005	52.58	0.00	13.77	0.00	0.00
2006	43.46	0.00	11.15	0.00	0.00
2007	29.26	0.00	7.17	0.00	0.00

Plan: CEN_PRG6 - Centralized Study Program 6

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	1.51	0.00	6.31	0.00	0.00	0.00	0.00
1996	2.18	0.00	13.56	0.00	0.00	0.00	0.00
1997	1.63	0.00	20.33	0.00	0.00	0.00	0.00
1998	1.63	0.00	20.34	0.00	0.00	0.00	0.00
1999	1.63	0.00	20.34	0.00	0.00	0.00	0.00
2000	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2001	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2002	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2003	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2004	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2005	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2006	0.00	0.00	0.00	0.00	0.00	0.00	0.00
2007	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG6 - Centralized Study Program 6

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(9.26)	(9.26)	(10.39)	(10.39)	116.91	0.02
1996	(20.17)	(29.43)	(24.10)	(34.50)	368.28	0.06
1997	(30.54)	(59.97)	(39.84)	(74.33)	745.45	0.11
1998	(34.11)	(94.08)	(50.05)	(124.39)	1,122.74	0.17
1999	(38.32)	(132.40)	(59.92)	(184.31)	1,500.14	0.23
2000	(16.96)	(149.36)	(37.30)	(221.60)	1,500.14	0.23
2001	(16.48)	(165.85)	(38.32)	(259.92)	1,500.14	0.23
2002	(16.19)	(182.03)	(39.16)	(299.08)	1,500.14	0.23
2003	(15.58)	(197.61)	(40.90)	(339.98)	1,500.14	0.23
2004	(15.36)	(212.98)	(41.68)	(381.66)	1,500.14	0.23
2005	(13.77)	(226.75)	(38.81)	(420.47)	1,383.23	0.21
2006	(11.15)	(237.89)	(32.31)	(452.78)	1,131.86	0.17
2007	(7.17)	(245.06)	(22.09)	(474.88)	754.69	0.11

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG6 - Centralized Study Program 6

PERSPECTIVES	PARTICIPANT TEST	OS UTILITY TEST	PS UTILITY TEST	OS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Inc.							
Cust. Nonelec. Bill Inc.	0.00						
Cust. O&M Cost Inc.	0.00					0.00	0.00
Cust. Cap. Invest. Inc.	265.60					221.22	239.03
Cust. Other Costs Inc.	0.00					0.00	0.00
Cust. Rebates Paid							
Cust. Income Tax Inc.							
OS Revenue Dec.				539.26			
OS Elec. Acq. Cost Inc.							
OS Nonelec. Revenue Dec.				0.00			
OS Nonelec. Acq. Cost Inc.		0.00		0.00			
OS Rebates Paid		66.40		66.40			
OS Cap. Rebates Paid		0.00		0.00			
OS Admin. Cost Inc.		65.04		65.04		60.89	65.04
OS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
OS Sales Tax Cost Inc.		0.00		0.00		0.00	
PS Revenue Dec.					293.66		
PS Elec. Proc. Cost Inc.							
PS Nonelec. Revenue Dec.							
PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
PS Rebates Paid			61.45		61.45		
PS Cap. Rebates Paid			0.00		0.00		
PS Admin. Cost Inc.			6.79		6.79	6.79	7.25
PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
Nonelec. Acq. Cost Inc.						0.00	0.00
Internal Environmental Cost							
External Environmental Cost							

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG6 - Centralized Study Program 6

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.	599.22						
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	132.80						
B	DS Revenue Inc.							
	DS Elec. Acq. Cost Dec.		347.53		347.53			
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.							
I	PS Elec. Prod. Cost Dec.			86.13		86.13	86.13	101.36
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Envirormental Ben.			0.00		0.00	0.00	0.00
	External Envirormental Ben.							10.14
	Total Costs	265.60	131.44	68.24	670.70	361.90	288.89	311.32
	Total Benefits	732.02	347.53	86.13	347.53	86.13	86.13	111.50
	Net Benefits	466.42	216.09	17.89	(323.17)	(275.78)	(202.77)	(199.82)
	Levelized Costs	28.57	14.14	8.52	72.16	45.18	36.07	33.49
	Levelized Benefits	78.75	37.39	10.75	37.39	10.75	10.75	12.00
	Levelized Costs ($/kWh)	28.1321	0.0139	0.0085	0.0710	0.0453	0.0361	0.0389
	Levelized Benefits ($/kWh)	77.5338	0.0368	0.0108	0.0368	0.0108	0.0108	0.0133
	Levelized Costs ($/kW)	187,075.28	92.58	56.77	472.40	301.06	240.32	258.98
	Levelized Benefits ($/kW)	515,591.60	244.78	71.65	244.78	71.65	71.65	92.75
	Benefit/Cost Ratio	2.76	2.64	1.26	0.52	0.24	0.30	0.36

EPRI DSManager

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG7 - Centralized Study Program 7

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_GSR	Res-Green River-Spc Cnd-GSHP Replacement
1994	2007	R_HU_GSR	Res-Hend Union-Spc Cnd-GSHP Replacement
1994	2007	R_JP_GSR	Res-Jackson Purchase-Spc Cnd GSHP Repla
1994	2007	R_MC_GSR	Res-Meade Cty-Space Cond-GSHP-Replacemnt

EPRI DSManager

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG7 - Centralized Study Program 7

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	(25.47)	0.00	(42.78)	0.00	0.00
1996	(60.04)	0.00	(97.55)	0.00	0.00
1997	(89.89)	0.00	(144.89)	0.00	0.00
1998	(123.85)	0.00	(191.93)	0.00	0.00
1999	(223.66)	0.00	(242.35)	0.00	0.00
2000	(651.35)	0.00	(301.26)	0.00	0.00
2001	(910.13)	0.00	(341.94)	0.00	0.00
2002	(1,174.07)	0.00	(388.83)	0.00	0.00
2003	(1,177.69)	0.00	(420.91)	0.00	0.00
2004	(1,451.33)	0.00	(460.89)	0.00	0.00
2005	(2,002.16)	0.00	(490.73)	0.00	0.00
2006	(2,290.32)	0.00	(535.93)	0.00	0.00
2007	(2,585.10)	0.00	(554.94)	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG7 - Centralized Study Program 7

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	29.68	0.00	310.05	0.00	0.00	0.00	0.00
1996	39.45	0.00	412.10	0.00	0.00	0.00	0.00
1997	39.51	0.00	412.75	0.00	0.00	0.00	0.00
1998	39.57	0.00	413.40	0.00	0.00	0.00	0.00
1999	39.57	0.00	413.40	0.00	0.00	0.00	0.00
2000	39.63	0.00	414.05	0.00	0.00	0.00	0.00
2001	39.63	0.00	414.05	0.00	0.00	0.00	0.00
2002	39.70	0.00	414.70	0.00	0.00	0.00	0.00
2003	39.70	0.00	414.70	0.00	0.00	0.00	0.00
2004	39.76	0.00	415.35	0.00	0.00	0.00	0.00
2005	39.82	0.00	416.00	0.00	0.00	0.00	0.00
2006	39.82	0.00	416.00	0.00	0.00	0.00	0.00
2007	39.95	0.00	417.30	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG7 - Centralized Study Program 7

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(296.94)	(296.94)	(357.05)	(357.05)	(3,724.31)	0.37
1996	(353.99)	(650.94)	(489.06)	(846.11)	(8,693.80)	0.87
1997	(307.36)	(958.30)	(507.27)	(1,353.38)	(13,671.05)	1.37
1998	(261.05)	(1,219.35)	(521.04)	(1,874.42)	(18,658.21)	1.87
1999	(210.62)	(1,429.97)	(471.66)	(2,346.08)	(23,647.55)	2.37
2000	(152.42)	(1,582.40)	(103.59)	(2,449.68)	(28,644.63)	2.87
2001	(111.75)	(1,694.14)	114.50	(2,335.17)	(33,643.89)	3.37
2002	(65.57)	(1,759.71)	330.85	(2,004.32)	(38,650.90)	3.87
2003	(33.49)	(1,793.20)	302.38	(1,701.94)	(43,660.07)	4.37
2004	5.78	(1,787.42)	535.33	(1,166.61)	(48,679.17)	4.87
2005	34.91	(1,752.51)	1,055.62	(110.99)	(53,726.01)	5.38
2006	80.11	(1,672.40)	1,298.56	1,187.57	(58,735.03)	5.88
2007	97.69	(1,574.70)	1,572.91	2,760.49	(63,731.67)	6.39

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG7 - Centralized Study Program 7

PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Inc.	15,922.13						
Cust. Nonelec. Bill Inc.	0.00						
Cust. O&M Cost Inc.	0.00					0.00	0.00
Cust. Cap. Invest. Inc.	14,274.20					11,734.84	13,557.28
Cust. Other Costs Inc.	0.00					0.00	0.00
Cust. Rebates Paid							
Cust. Income Tax Inc.							
DS Revenue Dec.							
DS Elec. Acq. Cost Inc.		7,131.67		7,131.67			
DS Nonelec. Revenue Dec.				0.00			
DS Nonelec. Acq. Cost Inc.		0.00		0.00			
DS Rebates Paid		3,568.55		3,568.55			
DS Cap. Rebates Paid		0.00		0.00			
DS Admin. Cost Inc.		3,074.44		3,074.44		2,661.20	3,074.44
DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
DS Sales Tax Cost Inc.		0.00		0.00		0.00	
PS Revenue Dec.							
PS Elec. Prod. Cost Inc.			2,115.06		2,115.06	2,115.06	2,557.22
PS Nonelec. Revenue Dec.							
PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
PS Rebates Paid			3,088.89		3,088.89		
PS Cap. Rebates Paid			0.00		0.00		
PS Admin. Cost Inc.			295.68		295.68	295.68	341.59
PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
Nonelec. Acq. Cost Inc.						0.00	0.00
Internal Environmental Cost							
External Environmental Cost							255.72

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG7 - Centralized Study Program 7

PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Dec.							
Cust. Nonelec. Bill Dec.							
Cust. O&M Cost Dec.							
Cust. Cap. Invest. Dec.							
Cust. Other Costs Dec.							
Cust. Income Tax Dec.	0.00					0.00	
Cust. Rebates Rec'ved	7,137.10						
DS Revenue Inc.				15,122.72			
DS Elec. Acq. Cost Dec.							
DS Nonelec. Revenue Dec.							
DS Nonelec. Acq. Cost Dec.							
DS Rebates Rec'ved							
DS Cap. Rebates Rec'ved							
DS Admin. Cost Dec.							
DS Cap. Admin. Cost Dec.							
DS Sales Tax Cost Dec.							
PS Revenue Inc.					5,686.48		
PS Elec. Prod. Cost Dec.							
PS Nonelec. Revenue Inc.					0.00		
PS Nonelec. Acq. Cost Dec.							
PS Gen. Cap. Credit							
PS Trans. Cap. Credit							
PS Dist. Cap. Credit							
PS Rebates Rec'ved							
PS Cap. Rebates Rec'ved							
PS Admin. Cost Dec.							
PS Cap. Admin. Cost Dec.							
Nonelec. Acq. Cost Dec.							
Internal Environmental Ben.			0.00		0.00	0.00	0.00
External Environmental Ben.							
Total Costs	30,196.38	13,774.67	5,499.62	13,774.67	5,499.62	16,306.77	19,786.27
Total Benefits	7,137.10	0.00	0.00	15,122.72	5,686.48	0.00	0.00
Net Benefits	(23,059.28)	(13,774.67)	(5,499.62)	1,348.06	186.86	(16,306.77)	(19,786.27)
Levelized Costs	3,248.68	1,481.95	686.59	1,481.95	686.59	2,098.20	2,128.70
Levelized Benefits	767.84	0.00	0.00	1,626.98	709.91	0.00	0.00
Levelized Costs ($/kWh)	(115.0747)	(0.0525)	(0.0255)	(0.0525)	(0.0255)	(0.0778)	(0.0915
Levelized Benefits ($/kWh)	(27.1986)	0.0000	0.0000	(0.0576)	(0.0263)	0.0000	0.0000
Levelized Costs ($/kW)	##.##	524.37	254.43	524.37	254.43	777.53	915.37
Levelized Benefits ($/kW)	271,693.56	0.00	0.00	575.69	263.07	0.00	0.00
Benefit/Cost Ratio	0.24	0.00	0.00	1.10	1.03	0.00	0.00

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG8 - Centralized Study Program 8

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_HPR	Res-Green River-Spc Cnd-ASHP Replacement
1994	2007	R_HU_HPR	Res-Hend Union-Spc Cnd-ASHP Replacement
1994	2007	R_JP_AHR	Res-Jackson-ASHP Replacement
1994	2007	R_MC_HPR	Res-Meade Cty-Space Con-ASHP Replacement

EPRI DSManager

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG8 - Centralized Study Program 8

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	(71.05)	0.00	(52.42)	0.00	0.00
1996	(171.31)	0.00	(121.95)	0.00	0.00
1997	(286.32)	0.00	(190.48)	0.00	0.00
1998	(515.48)	0.00	(256.27)	0.00	0.00
1999	(935.89)	0.00	(327.79)	0.00	0.00
2000	(1,624.25)	0.00	(408.89)	0.00	0.00
2001	(2,066.43)	0.00	(467.78)	0.00	0.00
2002	(2,547.16)	0.00	(533.38)	0.00	0.00
2003	(2,716.66)	0.00	(579.47)	0.00	0.00
2004	(3,293.08)	0.00	(636.34)	0.00	0.00
2005	(4,154.16)	0.00	(677.68)	0.00	0.00
2006	(4,757.64)	0.00	(738.77)	0.00	0.00
2007	(5,374.61)	0.00	(769.57)	0.00	0.00

Plan: CEN_PRG8 - Centralized Study Program 8

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	34.59	0.00	27.80	0.00	0.00	0.00	0.00
1996	48.16	0.00	38.70	0.00	0.00	0.00	0.00
1997	53.88	0.00	43.30	0.00	0.00	0.00	0.00
1998	53.94	0.00	43.35	0.00	0.00	0.00	0.00
1999	53.94	0.00	43.35	0.00	0.00	0.00	0.00
2000	53.94	0.00	43.35	0.00	0.00	0.00	0.00
2001	54.07	0.00	43.45	0.00	0.00	0.00	0.00
2002	54.07	0.00	43.45	0.00	0.00	0.00	0.00
2003	54.07	0.00	43.45	0.00	0.00	0.00	0.00
2004	54.13	0.00	43.50	0.00	0.00	0.00	0.00
2005	54.13	0.00	43.50	0.00	0.00	0.00	0.00
2006	54.26	0.00	43.60	0.00	0.00	0.00	0.00
2007	54.32	0.00	43.65	0.00	0.00	0.00	0.00

EPRI DSManager

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG8 - Centralized Study Program 8

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(9.98)	(9.98)	(43.76)	(43.76)	(4,533.53)	0.14
1996	35.10	25.12	(36.90)	(80.66)	(10,307.58)	0.32
1997	93.30	118.42	(1.34)	(82.01)	(17,731.21)	0.50
1998	158.98	277.39	161.91	79.91	(24,735.23)	0.69
1999	230.50	507.89	510.80	590.71	(31,749.31)	0.88
2000	311.60	819.49	1,118.06	1,708.77	(38,735.38)	1.07
2001	370.26	1,189.75	1,501.14	3,209.91	(45,740.30)	1.25
2002	435.86	1,625.61	1,916.26	5,126.17	(52,745.28)	1.44
2003	481.95	2,107.57	2,039.67	7,165.83	(59,752.24)	1.63
2004	538.70	2,646.27	2,559.11	9,724.94	(66,757.66)	1.82
2005	580.05	3,226.32	3,378.85	13,103.80	(73,785.07)	2.01
2006	640.92	3,867.23	3,921.02	17,024.81	(80,802.48)	2.20
2007	671.60	4,538.83	4,507.08	21,531.89	(87,830.34)	2.39

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG8 - Centralized Study Program 8

PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Inc.	22,637.56						
Cust. Nonelec. Bill Inc.	0.00						
Cust. O&M Cost Inc.	0.00					0.00	0.00
Cust. Cap. Invest. Inc.	731.06					568.37	658.38
Cust. Other Costs Inc.	0.00					0.00	0.00
Cust. Rebates Paid							
Cust. Income Tax Inc.							
DS Revenue Dec.							
DS Elec. Acq. Cost Inc.		16,204.95		16,204.95			
DS Nonelec. Revenue Dec.				0.00			
DS Nonelec. Acq. Cost Inc.		0.00		0.00			
DS Rebates Paid		365.53		365.53			
DS Cap. Rebates Paid		0.00		0.00			
DS Admin. Cost Inc.		4,093.93		4,093.93		3,534.31	4,093.93
DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
DS Sales Tax Cost Inc.		0.00		0.00		0.00	
PS Revenue Dec.							
PS Elec. Prod. Cost Inc.			2,876.36		2,876.36	2,876.36	3,483.12
PS Nonelec. Revenue Dec.							
PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
PS Rebates Paid			315.56		315.56		
PS Cap. Rebates Paid			0.00		0.00		
PS Admin. Cost Inc.			392.69		392.69	392.69	454.87
PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
Nonelec. Acq. Cost Inc.						0.00	0.00
Internal Environmental Cost							
External Environmental Cost							348.31

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG8 - Centralized Study Program 8

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.							
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	731.06						
B	DS Revenue Inc.				20,388.03			
	DS Elec. Acq. Cost Dec.							
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.					13,021.28		
I	PS Elec. Prod. Cost Dec.							
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							
	Total Costs	23,368.62	20,664.41	3,584.61	20,664.41	3,584.61	7,371.73	9,038.59
	Total Benefits	731.06	0.00	0.00	20,388.03	13,021.28	0.00	0.00
	Net Benefits	(22,637.56)	(20,664.41)	(3,584.61)	(276.38)	9,436.67	(7,371.73)	(9,038.59)
	Levelized Costs	2,514.11	2,223.18	447.51	2,223.18	447.51	920.30	972.42
	Levelized Benefits	78.65	0.00	0.00	2,193.44	1,625.61	0.00	0.00
	Levelized Costs ($/kWh)	(65.6717)	(0.0581)	(0.0123)	(0.0581)	(0.0123)	(0.0252)	(0.0309)
	Levelized Benefits ($/kWh)	(2.0545)	0.0000	0.0000	(0.0573)	(0.0445)	0.0000	0.0000
	Levelized Costs ($/kW)	##.##	2,110.35	445.07	2,110.35	445.07	915.28	1,122.24
	Levelized Benefits ($/kW)	74,659.38	0.00	0.00	2,082.13	1,616.73	0.00	0.00
	Benefit/Cost Ratio	0.03	0.00	0.00	0.99	3.63	0.00	0.00

Demand-Side Management Plan

Plan: CEN_PRG9 - Centralized Study Program 9

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_RPL	Res-Green River-Wtr Heat-Htr Replace-52G
1994	2007	R_HU_RPL	Res-Hen Union-Wtr Heat-Htr Replace 52 G
1994	2007	R_JP_RPL	Res-Jackson-Wtr Heat-Htr Replace-52G
1994	2007	R_MC_RPL	Res-Meade Cty-Wtr Heat-Replacement

EPRI DSManager

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG9 - Centralized Study Program 9

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	(24.69)	0.00	(8.41)	0.00	0.00
1996	(85.98)	0.00	(28.26)	0.00	0.00
1997	(181.12)	0.00	(55.78)	0.00	0.00
1998	(277.63)	0.00	(79.58)	0.00	0.00
1999	(376.03)	0.00	(107.53)	0.00	0.00
2000	(472.40)	0.00	(140.21)	0.00	0.00
2001	(573.65)	0.00	(163.78)	0.00	0.00
2002	(677.27)	0.00	(188.07)	0.00	0.00
2003	(789.34)	0.00	(207.06)	0.00	0.00
2004	(897.94)	0.00	(229.99)	0.00	0.00
2005	(1,000.53)	0.00	(248.95)	0.00	0.00
2006	(1,112.59)	0.00	(271.23)	0.00	0.00
2007	(1,227.00)	0.00	(285.59)	0.00	0.00

Plan: CEN_PRG9 - Centralized Study Program 9

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	0.58	0.00	3.65	0.00	0.00	0.00	0.00
1996	1.43	0.00	8.93	0.00	0.00	0.00	0.00
1997	2.15	0.00	13.42	0.00	0.00	0.00	0.00
1998	2.15	0.00	13.45	0.00	0.00	0.00	0.00
1999	2.15	0.00	13.45	0.00	0.00	0.00	0.00
2000	2.15	0.00	13.45	0.00	0.00	0.00	0.00
2001	2.15	0.00	13.42	0.00	0.00	0.00	0.00
2002	2.16	0.00	13.48	0.00	0.00	0.00	0.00
2003	2.15	0.00	13.45	0.00	0.00	0.00	0.00
2004	2.16	0.00	13.48	0.00	0.00	0.00	0.00
2005	2.16	0.00	13.50	0.00	0.00	0.00	0.00
2006	2.16	0.00	13.48	0.00	0.00	0.00	0.00
2007	2.16	0.00	13.50	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG9 - Centralized Study Program 9

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	4.18	4.18	12.04	12.04	(678.75)	(0.10)
1996	17.90	22.08	47.37	59.41	(2,342.03)	(0.36)
1997	40.21	62.29	109.77	169.17	(4,844.82)	(0.75)
1998	63.98	126.27	182.45	351.62	(7,352.79)	(1.14)
1999	91.93	218.20	252.90	604.52	(9,860.83)	(1.52)
2000	124.61	342.81	316.58	921.10	(12,368.88)	(1.91)
2001	148.20	491.02	394.30	1,315.40	(14,871.79)	(2.30)
2002	172.44	663.45	473.57	1,788.97	(17,385.09)	(2.68)
2003	191.45	854.91	566.68	2,355.65	(19,893.25)	(3.07)
2004	214.36	1,069.27	652.31	3,007.96	(22,406.58)	(3.46)
2005	233.29	1,302.56	735.92	3,743.89	(24,930.25)	(3.85)
2006	255.60	1,558.17	825.73	4,569.61	(27,448.79)	(4.24)
2007	269.93	1,828.10	925.75	5,495.36	(29,972.50)	(4.63)

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG9 - Centralized Study Program 9

PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Inc.	7,549.56						
Cust. Nonelec. Bill Inc.	0.00						
Cust. O&M Cost Inc.	0.00					0.00	0.00
Cust. Cap. Invest. Inc.	0.00					0.00	0.00
Cust. Other Costs Inc.	0.00					0.00	0.00
Cust. Rebates Paid							
Cust. Income Tax Inc.							
DS Revenue Dec.							
DS Elec. Acq. Cost Inc.		4,516.11		4,516.11			
DS Nonelec. Revenue Dec.				0.00			
DS Nonelec. Acq. Cost Inc.		0.00		0.00			
DS Rebates Paid		105.85		105.85			
DS Cap. Rebates Paid		0.00		0.00			
DS Admin. Cost Inc.		152.42		152.42		130.47	152.42
DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
DS Sales Tax Cost Inc.		0.00		0.00		0.00	
PS Revenue Dec.							
PS Elec. Prod. Cost Inc.			984.11		984.11	984.11	1,199.89
PS Nonelec. Revenue Dec.							
PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
PS Rebates Paid			90.60		90.60		
PS Cap. Rebates Paid			0.00		0.00		
PS Admin. Cost Inc.			14.50		14.50	14.50	16.94
PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
Nonelec. Acq. Cost Inc.						0.00	0.00
Internal Environmental Cost							
External Environmental Cost							119.99

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG9 - Centralized Study Program 9

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.							
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	211.70						
B	DS Revenue Inc.				6,791.69			
	DS Elec. Acq. Cost Dec.							
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.					3,680.91		
I	PS Elec. Prod. Cost Dec.							
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							
	Total Costs	7,549.56	4,774.39	1,089.22	4,774.39	1,089.22	1,129.08	1,489.24
	Total Benefits	211.70	0.00	0.00	6,791.69	3,680.91	0.00	0.00
	Net Benefits	(7,337.86)	(4,774.39)	(1,089.22)	2,017.30	2,591.70	(1,129.08)	(1,489.24)
	Levelized Costs	812.22	513.65	135.98	513.65	135.98	140.96	160.22
	Levelized Benefits	22.78	0.00	0.00	730.68	459.53	0.00	0.00
	Levelized Costs ($/kWh)	(65.8683)	(0.0417)	(0.0116)	(0.0417)	(0.0116)	(0.0121)	(0.0159)
	Levelized Benefits ($/kWh)	(1.8470)	0.0000	0.0000	(0.0593)	(0.0393)	0.0000	0.0000
	Levelized Costs ($/kW)	(426,548.97)	(269.75)	(75.34)	(269.75)	(75.34)	(78.10)	(103.02)
	Levelized Benefits ($/kW)	(11,961.05)	0.00	0.00	(383.73)	(254.62)	0.00	0.00
	Benefit/Cost Ratio	0.03	0.00	0.00	1.42	3.38	0.00	0.00

EPRI DSManager

Jackson Purchase Electric (Rural)

Demand-Side Management Plan

Plan: CEN_PR10 - Centralized Study Program 10

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	CG_GR_HR	C/I-Grocery-Green Riv-Wtg Htg-Htr Replce
1994	2007	CG_JP_HR	C/I-Grocery-Jack Pur-Wtr Htg-Heater Repl
1994	2007	CG_MC_HR	C/I-Grocery-Meade Cty-Wtr Htg-Heater Rpl
1994	2007	CR_GR_HR	C/I-Res-Green Riv-Wtr Htg-Heater Replace
1994	2007	CR_JP_HR	C/I-Res-Jack Pur-Wtr Htg-Heater Replace
1994	2007	CR_MC_HR	C/I-Res-Meade Cty-Wtr Htg-Heater Replace
1994	2007	CS_GR_HR	C/I-School-Green Riv-Wat Htg-Heater Repl
1994	2007	CS_JP_HR	C/I-School-Jack Pur-Wat Htg-Heater Replc

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PR10 - Centralized Study Program 10

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	0.00	0.00	0.00	0.00	0.00
1996	(2.11)	0.00	(0.69)	0.00	0.00
1997	(4.25)	0.00	(1.31)	0.00	0.00
1998	(6.44)	0.00	(1.84)	0.00	0.00
1999	(8.68)	0.00	(2.49)	0.00	0.00
2000	(10.96)	0.00	(3.23)	0.00	0.00
2001	(13.28)	0.00	(3.76)	0.00	0.00
2002	(15.65)	0.00	(4.30)	0.00	0.00
2003	(18.06)	0.00	(4.73)	0.00	0.00
2004	(20.52)	0.00	(5.24)	0.00	0.00
2005	(23.03)	0.00	(5.69)	0.00	0.00
2006	(25.59)	0.00	(6.19)	0.00	0.00
2007	(28.19)	0.00	(6.52)	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PR10 - Centralized Study Program 10

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1996	0.01	0.00	0.05	0.00	0.00	0.00	0.00
1997	0.01	0.00	0.05	0.00	0.00	0.00	0.00
1998	0.01	0.00	0.05	0.00	0.00	0.00	0.00
1999	0.01	0.00	0.05	0.00	0.00	0.00	0.00
2000	0.01	0.00	0.05	0.00	0.00	0.00	0.00
2001	0.01	0.00	0.05	0.00	0.00	0.00	0.00
2002	0.01	0.00	0.05	0.00	0.00	0.00	0.00
2003	0.01	0.00	0.05	0.00	0.00	0.00	0.00
2004	0.01	0.00	0.05	0.00	0.00	0.00	0.00
2005	0.01	0.00	0.05	0.00	0.00	0.00	0.00
2006	0.01	0.00	0.05	0.00	0.00	0.00	0.00
2007	0.01	0.00	0.05	0.00	0.00	0.00	0.00

Plan: CEN_PR10 - Centralized Study Program 10

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	0.00	0.00	0.00	0.00	0.00	0.00
1996	0.63	0.63	1.36	1.36	(56.07)	(0.01)
1997	1.25	1.88	2.88	4.24	(112.14)	(0.02)
1998	1.78	3.66	4.55	8.79	(168.21)	(0.02)
1999	2.44	6.10	6.13	14.92	(224.28)	(0.03)
2000	3.17	9.27	7.67	22.59	(280.35)	(0.04)
2001	3.71	12.98	9.46	32.05	(336.42)	(0.05)
2002	4.24	17.21	11.29	43.34	(392.49)	(0.06)
2003	4.67	21.88	13.28	56.62	(448.56)	(0.06)
2004	5.18	27.07	15.23	71.84	(504.63)	(0.07)
2005	5.63	32.70	17.28	89.12	(560.70)	(0.08)
2006	6.13	38.83	19.34	108.46	(616.77)	(0.09)
2007	6.46	45.29	21.62	130.08	(672.84)	(0.10)

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PR10 - Centralized Study Program 10

	PERSPECTIVES Data discounted to 1994	PARTICIPANT TEST ('000 $)	DS UTILITY TEST ('000 $)	PS UTILITY TEST ('000 $)	DS RATEPAYER IMPACT TEST ('000 $)	PS RATEPAYER IMPACT TEST ('000 $)	TOTAL RESOURCE TEST ('000 $)	SOCIETAL TEST ('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Inc.	185.81						
	Cust. Nonelec. Bill Inc.	0.00						
	Cust. O&M Cost Inc.	0.00					0.00	0.00
	Cust. Cap. Invest. Inc.	0.00					0.00	0.00
	Cust. Other Costs Inc.	0.00					0.00	0.00
	Cust. Rebates Paid							
	Cust. Income Tax Inc.							
	DS Revenue Dec.							
	DS Elec. Acq. Cost Inc.		103.63		103.63			
C	DS Nonelec. Revenue Dec.				0.00			
	DS Nonelec. Acq. Cost Inc.		0.00		0.00			
O	DS Rebates Paid		0.40		0.40			
	DS Cap. Rebates Paid		0.00		0.00			
S	DS Admin. Cost Inc.		0.57		0.57		0.49	0.57
	DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
T	DS Sales Tax Cost Inc.		0.00		0.00		0.00	
	PS Revenue Dec.							
S	PS Elec. Prod. Cost Inc.			22.43		22.43	22.43	27.36
	PS Nonelec. Revenue Dec.							
	PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
	PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
	PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
	PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
	PS Rebates Paid			0.34		0.34		
	PS Cap. Rebates Paid			0.00		0.00		
	PS Admin. Cost Inc.			0.05		0.05	0.05	0.05
	PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
	Nonelec. Acq. Cost Inc.						0.00	0.00
	Internal Environmental Cost							
	External Environmental Cost							2.74

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PR10 - Centralized Study Program 10

PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Dec.							
Cust. Nonelec. Bill Dec.							
Cust. O&M Cost Dec.							
Cust. Cap. Invest. Dec.							
Cust. Other Costs Dec.							
Cust. Income Tax Dec.	0.00					0.00	
Cust. Rebates Rec'ved	0.79						
DS Revenue Inc.				185.81			
DS Elec. Acq. Cost Dec.							
DS Nonelec. Revenue Dec.							
DS Nonelec. Acq. Cost Dec.							
DS Rebates Rec'ved							
DS Cap. Rebates Rec'ved							
DS Admin. Cost Dec.							
DS Cap. Admin. Cost Dec.							
DS Sales Tax Cost Dec.							
PS Revenue Inc.					84.41		
PS Elec. Prod. Cost Dec.							
PS Nonelec. Revenue Inc.					0.00		
PS Nonelec. Acq. Cost Dec.							
PS Gen. Cap. Credit							
PS Trans. Cap. Credit							
PS Dist. Cap. Credit							
PS Rebates Rec'ved							
PS Cap. Rebates Rec'ved							
PS Admin. Cost Dec.							
PS Cap. Admin. Cost Dec.							
Nonelec. Acq. Cost Dec.							
Internal Environmental Ben.			0.00		0.00	0.00	0.00
External Environmental Ben.							
Total Costs	185.81	104.59	22.82	104.59	22.82	22.97	30.73
Total Benefits	0.79	0.00	0.00	185.81	84.41	0.00	0.00
Net Benefits	(185.02)	(104.59)	(22.82)	81.22	61.60	(22.97)	(30.73)
Levelized Costs	19.99	11.25	2.85	11.25	2.85	2.87	3.31
Levelized Benefits	0.09	0.00	0.00	19.99	10.54	0.00	0.00
Levelized Costs ($/kWh)	(72.1011)	(0.0406)	(0.0108)	(0.0406)	(0.0108)	(0.0109)	(0.0146)
Levelized Benefits ($/kWh)	(0.3069)	0.0000	0.0000	(0.0721)	(0.0401)	0.0000	0.0000
Levelized Costs ($/kW)	(510,172.20)	(287.17)	(76.74)	(287.17)	(76.74)	(77.24)	(103.35)
Levelized Benefits ($/kW)	(2,171.59)	0.00	0.00	(510.17)	(283.90)	0.00	0.00
Benefit/Cost Ratio	0.00	0.00	0.00	1.78	3.70	0.00	0.00

EPRI DSManager

Jackson Purchase Electric (Rural)

Demand-Side Management Plan

Plan: CEN_PR11 - Centralized Study Program 11

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	CE_GR_HP	C/I-Retail-Green Riv-HVAC-Heat Pump Rplc
1994	2007	CE_JP_HP	C/I-Retail-Jack Pur-HVAC-Heat Pump Rplc
1994	2007	CE_MC_HP	C/I-Retail-Meade Cty-HVAC-Heat Pump Rplc
1994	2007	CO_GR_HP	C/I-Office-Green Riv-HVAC-Heat Pump Rplc
1994	2007	CO_JP_HP	C/I-Office-Jack Pur-HVAC-Heat Pump Rplc
1994	2007	CO_MC_HP	C/I-Office-Meade Cty-HVAC-Heat Pump Rplc
1994	2007	CS_GR_HP	C/I-School-Green Riv-HVAC-Heat Pump Rplc
1994	2007	CS_JP_HP	C/I-School-Jack Pur-HVAC-Heat Pump Rplc

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PR11 - Centralized Study Program 11

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	(1.32)	0.00	(0.69)	0.00	0.00
1996	(3.94)	0.00	(1.98)	0.00	0.00
1997	(8.02)	0.00	(3.74)	0.00	0.00
1998	(12.12)	0.00	(5.36)	0.00	0.00
1999	(16.29)	0.00	(7.13)	0.00	0.00
2000	(20.19)	0.00	(9.19)	0.00	0.00
2001	(24.46)	0.00	(10.68)	0.00	0.00
2002	(28.81)	0.00	(12.24)	0.00	0.00
2003	(33.83)	0.00	(13.49)	0.00	0.00
2004	(38.42)	0.00	(14.93)	0.00	0.00
2005	(42.37)	0.00	(16.04)	0.00	0.00
2006	(47.07)	0.00	(17.49)	0.00	0.00
2007	(51.85)	0.00	(18.38)	0.00	0.00

Power Supplier Summary Report

Plan: CEN_PR11 - Centralized Study Program 11

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	2.30	0.00	1.85	0.00	0.00	0.00	0.00
1996	4.60	0.00	3.70	0.00	0.00	0.00	0.00
1997	6.91	0.00	5.55	0.00	0.00	0.00	0.00
1998	6.91	0.00	5.55	0.00	0.00	0.00	0.00
1999	6.91	0.00	5.55	0.00	0.00	0.00	0.00
2000	6.91	0.00	5.55	0.00	0.00	0.00	0.00
2001	6.91	0.00	5.55	0.00	0.00	0.00	0.00
2002	6.91	0.00	5.55	0.00	0.00	0.00	0.00
2003	6.91	0.00	5.55	0.00	0.00	0.00	0.00
2004	6.91	0.00	5.55	0.00	0.00	0.00	0.00
2005	6.91	0.00	5.55	0.00	0.00	0.00	0.00
2006	6.91	0.00	5.55	0.00	0.00	0.00	0.00
2007	6.91	0.00	5.55	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PR11 - Centralized Study Program 11

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(3.46)	(3.46)	(3.52)	(3.52)	(58.44)	0.00
1996	(6.32)	(9.79)	(6.35)	(9.87)	(172.19)	(0.01)
1997	(8.71)	(18.50)	(8.17)	(18.04)	(341.24)	(0.01)
1998	(7.10)	(25.60)	(5.70)	(23.74)	(510.30)	(0.02)
1999	(5.32)	(30.92)	(3.30)	(27.03)	(679.36)	(0.02)
2000	(3.27)	(34.19)	(1.45)	(28.48)	(848.42)	(0.03)
2001	(1.78)	(35.97)	1.33	(27.16)	(1,017.47)	(0.04)
2002	(0.22)	(36.19)	4.12	(23.04)	(1,186.53)	(0.04)
2003	1.03	(35.16)	7.88	(15.16)	(1,355.59)	(0.05)
2004	2.47	(32.69)	11.04	(4.11)	(1,524.65)	(0.05)
2005	3.59	(29.10)	13.87	9.76	(1,693.70)	(0.06)
2006	5.03	(24.07)	17.12	26.88	(1,862.76)	(0.07)
2007	5.93	(18.15)	21.01	47.89	(2,031.82)	(0.07)

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PR11 - Centralized Study Program 11

	PERSPECTIVES Data discounted to 1994	PARTICIPANT TEST ('000 $)	DS UTILITY TEST ('000 $)	PS UTILITY TEST ('000 $)	DS RATEPAYER IMPACT TEST ('000 $)	PS RATEPAYER IMPACT TEST ('000 $)	TOTAL RESOURCE TEST ('000 $)	SOCIETAL TEST ('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Inc.	598.95						
	Cust. Nonelec. Bill Inc.	0.00						
	Cust. O&M Cost Inc.	0.00					0.00	0.00
	Cust. Cap. Invest. Inc.	0.00					0.00	0.00
	Cust. Other Costs Inc.	0.00					0.00	0.00
	Cust. Rebates Paid							
	Cust. Income Tax Inc.							
	DS Revenue Dec.							
	DS Elec. Acq. Cost Inc.		193.34		193.34			
C	DS Nonelec. Revenue Dec.				0.00			
	DS Nonelec. Acq. Cost Inc.		0.00		0.00			
O	DS Rebates Paid		44.00		44.00			
	DS Cap. Rebates Paid		0.00		0.00			
S	DS Admin. Cost Inc.		492.75		492.75		422.28	492.75
	DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
T	DS Sales Tax Cost Inc.		0.00		0.00		0.00	
	PS Revenue Dec.							
S	PS Elec. Prod. Cost Inc.			64.44		64.44	64.44	78.46
	PS Nonelec. Revenue Dec.							
	PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
	PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
	PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
	PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
	PS Rebates Paid			37.70		37.70		
	PS Cap. Rebates Paid			0.00		0.00		
	PS Admin. Cost Inc.			46.92		46.92	46.92	54.75
	PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
	Nonelec. Acq. Cost Inc.						0.00	0.00
	Internal Environmental Cost							
	External Environmental Cost							7.85

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PR11 - Centralized Study Program 11

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.							
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	87.99						
B	DS Revenue Inc.				549.42			
	DS Elec. Acq. Cost Dec.							
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.					157.76		
I	PS Elec. Prod. Cost Dec.							
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							
	Total Costs	598.95	730.08	149.06	730.08	149.06	533.64	633.81
	Total Benefits	87.99	0.00	0.00	549.42	157.76	0.00	0.00
	Net Benefits	(510.96)	(730.08)	(149.06)	(180.67)	8.70	(533.64)	(633.81)
	Levelized Costs	64.44	78.55	18.61	78.55	18.61	66.62	68.19
	Levelized Benefits	9.47	0.00	0.00	59.11	19.70	0.00	0.00
	Levelized Costs ($/kWh)	(76.2956)	(0.0930)	(0.0232)	(0.0930)	(0.0232)	(0.0831)	(0.0987)
	Levelized Benefits ($/kWh)	(11.2086)	0.0000	0.0000	(0.0700)	(0.0246)	0.0000	0.0000
	Levelized Costs ($/kW)	##.##	(2,583.13)	(645.05)	(2,583.13)	(645.05)	(2,309.24)	(2,742.71)
	Levelized Benefits ($/kW)	(311,322.08)	0.00	0.00	(1,943.90)	(682.68)	0.00	0.00
	Benefit/Cost Ratio	0.15	0.00	0.00	0.75	1.06	0.00	0.00

13

Item 13) If Figure IV-1 is not an original drawing, please provide the reference.

Response) Figure IV-1 is not an original drawing. It is taken from the work of Armando J. de Leon, PE, an engineer with Burns & McDonnell Engineering. Mr. de Leon's work was inspired by the work of Clark Gellings, in the 1980's. Mr. Gellings is currently EPRI's Vice President of Customer Systems. A similar diagram has appeared in several EPRI publications.

Witness) Armando de Leon
Burns & McDonnell

14

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 14) The first paragraph on page IV-5 implies that Burns & McDonnell performed an analysis of certain DSM programs considered in the 1995 study by R. W. Beck. Please provide a copy of this analysis, including any working papers.

Response) Burns & McDonnell reviewed the R. W. Beck study and considered options which were viable at the time of the study. Given the industry's general trend toward lower capacity costs and commodity purchases and sales, Burns & McDonnell was able to eliminate several programs which were considered in 1995.

The work papers associated with this process are attached to this response.

Witness) Armando de Leon
Burns & McDonnell

Response to KDOE Questions 14 and 16 – Work papers
Evaluation of Replacement of Water heaters and Non-electric heat Systems

a) Non-electric heat systems
  1. Benefits:
     Increase sales
     Fuel switch
     Increase customer loyalty
  2. Costs (negatives):
     Increase coincident peak
     Incentives
     Administrative
     Marketing

See attached DSManager Print Outs
- Participant Test Scores of 0.03
- Utility test Score of 0.00
- RIM tests of 1.42 and 3.38 (at different discount rates)
  - Indicates great sensitivity to discount rates and time till capacity additions
- Total resource Cost test score of 0.00

In light of competition, energy costs have dropped and capacity costs have likewise. Emission credits, etc., unaffected. See attached runs of DSManager. Burns & McDonnell recommends no action here.

Evaluation of Space heater Fuel Switch program

b) Non-electric heat systems
  1. Benefits:
     Increase sales
     Fuel switch
     Increase customer loyalty
  2. Costs (negatives):
     Increase coincident peak
     Incentives
     Administrative
     Marketing

See attached DSManager Print Outs
- Participant Test Scores of 0.24
- Utility test Score of 0.00
- RIM tests of 1.10 and 1.03 (at different discount rates)
  - Indicates great sensitivity to discount rates and time till capacity additions
- Total resource Cost test score of 0.00

In light of competition, energy costs have dropped and capacity costs have likewise. Emission credits, etc., unaffected. See attached. Burns & McDonnell commends no action.

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG9 - Centralized Study Program 9

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_RPL	Res-Green River-Wtr Heat-Htr Replace-52G
1994	2007	R_HU_RPL	Res-Hen Union-Wtr Heat-Htr Replace 52 G
1994	2007	R_JP_RPL	Res-Jackson-Wtr Heat-Htr Replace-52G
1994	2007	R_MC_RPL	Res-Meade Cty-Wtr Heat-Replacement

EPRI DSManager

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG9 - Centralized Study Program 9

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	(24.69)	0.00	(3.41)	0.00	0.00
1996	(85.98)	0.00	(28.26)	0.00	0.00
1997	(181.12)	0.00	(55.78)	0.00	0.00
1998	(277.63)	0.00	(79.58)	0.00	0.00
1999	(376.03)	0.00	(107.53)	0.00	0.00
2000	(472.40)	0.00	(140.21)	0.00	0.00
2001	(573.65)	0.00	(153.78)	0.00	0.00
2002	(677.27)	0.00	(188.07)	0.00	0.00
2003	(789.34)	0.00	(207.05)	0.00	0.00
2004	(897.94)	0.00	(229.99)	0.00	0.00
2005	(1,000.53)	0.00	(248.35)	0.00	0.00
2006	(1,112.59)	0.00	(271.23)	0.00	0.00
2007	(1,227.00)	0.00	(285.59)	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG9 - Centralized Study Program 9

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	0.58	0.00	3.65	0.00	0.00	0.00	0.00
1996	1.43	0.00	8.93	0.00	0.00	0.00	0.00
1997	2.15	0.00	13.42	0.00	0.00	0.00	0.00
1998	2.15	0.00	13.45	0.00	0.00	0.00	0.00
1999	2.15	0.00	13.45	0.00	0.00	0.00	0.00
2000	2.15	0.00	13.45	0.00	0.00	0.00	0.00
2001	2.15	0.00	13.42	0.00	0.00	0.00	0.00
2002	2.16	0.00	13.48	0.00	0.00	0.00	0.00
2003	2.15	0.00	13.45	0.00	0.00	0.00	0.00
2004	2.16	0.00	13.48	0.00	0.00	0.00	0.00
2005	2.16	0.00	13.50	0.00	0.00	0.00	0.00
2006	2.16	0.00	13.48	0.00	0.00	0.00	0.00
2007	2.16	0.00	13.50	0.00	0.00	0.00	0.00

EPRI DSManager

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG9 - Centralized Study Program 9

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	4.18	4.18	12.04	12.04	(678.75)	(0.10)
1996	17.90	22.08	47.37	59.41	(2,342.03)	(0.36)
1997	40.21	62.29	109.77	169.17	(4,844.82)	(0.75)
1998	63.98	126.27	182.45	351.62	(7,352.79)	(1.14)
1999	91.93	218.20	252.90	604.52	(9,860.83)	(1.52)
2000	124.61	342.81	316.58	921.10	(12,368.88)	(1.91)
2001	148.20	491.02	394.30	1,315.40	(14,871.79)	(2.30)
2002	172.44	663.45	473.57	1,788.97	(17,385.09)	(2.68)
2003	191.45	854.91	566.68	2,355.65	(19,893.25)	(3.07)
2004	214.36	1,069.27	652.31	3,007.96	(22,406.58)	(3.46)
2005	233.29	1,302.56	735.92	3,743.89	(24,930.25)	(3.85)
2006	255.60	1,558.17	825.73	4,569.61	(27,448.79)	(4.24)
2007	269.93	1,828.10	925.75	5,495.35	(29,972.50)	(4.63)

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG9 - Centralized Study Program 9

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Inc.	7,549.56						
	Cust. Nonelec. Bill Inc.	0.00						
	Cust. O&M Cost Inc.	0.00					0.00	0.00
	Cust. Cap. Invest. Inc.	0.00					0.00	0.00
	Cust. Other Costs Inc.	0.00					0.00	0.00
	Cust. Rebates Paid							
	Cust. Income Tax Inc.							
	DS Revenue Dec.							
	DS Elec. Acq. Cost Inc.		4,516.11		4,516.11			
C	DS Nonelec. Revenue Dec.				0.00			
	DS Nonelec. Acq. Cost Inc.		0.00		0.00			
O	DS Rebates Paid		105.85		105.85			
	DS Cap. Rebates Paid		0.00		0.00			
S	DS Admin. Cost Inc.		152.42		152.42		130.47	152.42
	DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
T	DS Sales Tax Cost Inc.		0.00		0.00		0.00	
	PS Revenue Dec.							
S	PS Elec. Prod. Cost Inc.			984.11		984.11	984.11	1,199.93
	PS Nonelec. Revenue Dec.							
	PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
	PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
	PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
	PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
	PS Rebates Paid			90.60		90.60		
	PS Cap. Rebates Paid			0.00		0.00		
	PS Admin. Cost Inc.			14.50		14.50	14.50	16.94
	PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
	Nonelec. Acq. Cost Inc.						0.00	0.00
	Internal Environmental Cost							
	External Environmental Cost							119.99

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG9 - Centralized Study Program 9

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.							
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	211.70						
B	DS Revenue Inc.				6,791.69			
	DS Elec. Acq. Cost Dec.							
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.					3,680.91		
I	PS Elec. Prod. Cost Dec.							
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							
	Total Costs	7,549.56	4,774.39	1,089.22	4,774.39	1,089.22	1,129.08	1,489.24
	Total Benefits	211.70	0.00	0.00	6,791.69	3,680.91	0.00	0.00
	Net Benefits	(7,337.86)	(4,774.39)	(1,089.22)	2,017.30	2,591.70	(1,129.08)	(1,489.24)
	Levelized Costs	812.22	513.65	135.98	513.65	135.98	140.96	160.22
	Levelized Benefits	22.78	0.00	0.00	730.68	459.53	0.00	0.00
	Levelized Costs ($/kWh)	(65.8683)	(0.0417)	(0.0116)	(0.0417)	(0.0116)	(0.0121)	(0.0159)
	Levelized Benefits ($/kWh)	(1.8470)	0.0000	0.0000	(0.0593)	(0.0393)	0.0000	0.0000
	Levelized Costs ($/kW)	(426,548.97)	(269.75)	(75.34)	(269.75)	(75.34)	(78.10)	(103.02)
	Levelized Benefits ($/kW)	(11,961.05)	0.00	0.00	(383.73)	(254.62)	0.00	0.00
	Benefit/Cost Ratio	0.03	0.00	0.00	1.42	3.38	0.00	0.00

EPRI DSManager

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG7 - Centralized Study Program 7

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_GSR	Res-Green River-Spc Cnd-GSHP Replacement
1994	2007	R_HU_GSR	Res-Hend Union-Spc Cnd-GSHP Replacement
1994	2007	R_JP_GSR	Res-Jackson Purchase-Spc Cnd GSHP Repla
1994	2007	R_MC_GSR	Res-Meade Cty-Space Cond-GSHP-Replacemnt

EPRI DSManager

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG7 - Centralized Study Program 7

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	(25.47)	0.00	(42.78)	0.00	0.00
1996	(60.04)	0.00	(97.55)	0.00	0.00
1997	(89.89)	0.00	(144.89)	0.00	0.00
1998	(123.85)	0.00	(191.93)	0.00	0.00
1999	(223.66)	0.00	(242.35)	0.00	0.00
2000	(651.35)	0.00	(301.26)	0.00	0.00
2001	(912.13)	0.00	(341.94)	0.00	0.00
2002	(1,174.07)	0.00	(388.83)	0.00	0.00
2003	(1,177.69)	0.00	(420.91)	0.00	0.00
2004	(1,451.33)	0.00	(460.89)	0.00	0.00
2005	(2,002.16)	0.00	(490.73)	0.00	0.00
2006	(2,290.32)	0.00	(535.93)	0.00	0.00
2007	(2,585.10)	0.00	(554.94)	0.00	0.00

Plan: CEN_PRG7 - Centralized Study Program 7

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	29.68	0.00	310.05	0.00	0.00	0.00	0.00
1996	39.45	0.00	412.10	0.00	0.00	0.00	0.00
1997	39.51	0.00	412.75	0.00	0.00	0.00	0.00
1998	39.57	0.00	413.40	0.00	0.00	0.00	0.00
1999	39.57	0.00	413.40	0.00	0.00	0.00	0.00
2000	39.63	0.00	414.05	0.00	0.00	0.00	0.00
2001	39.63	0.00	414.05	0.00	0.00	0.00	0.00
2002	39.70	0.00	414.70	0.00	0.00	0.00	0.00
2003	39.70	0.00	414.70	0.00	0.00	0.00	0.00
2004	39.76	0.00	415.35	0.00	0.00	0.00	0.00
2005	39.82	0.00	416.00	0.00	0.00	0.00	0.00
2006	39.82	0.00	416.00	0.00	0.00	0.00	0.00
2007	39.95	0.00	417.30	0.00	0.00	0.00	0.00

Plan: CEN_PRG7 - Centralized Study Program 7

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(296.94)	(296.94)	(357.05)	(357.05)	(3,724.31)	0.37
1996	(353.99)	(650.94)	(489.06)	(846.11)	(8,693.80)	0.87
1997	(307.36)	(958.30)	(507.27)	(1,353.38)	(13,671.05)	1.37
1998	(261.05)	(1,219.35)	(521.04)	(1,874.42)	(18,658.21)	1.87
1999	(210.62)	(1,429.97)	(471.66)	(2,346.08)	(23,647.55)	2.37
2000	(152.42)	(1,582.40)	(103.59)	(2,449.68)	(28,644.63)	2.87
2001	(111.75)	(1,694.14)	114.50	(2,335.17)	(33,643.89)	3.37
2002	(65.57)	(1,759.71)	330.85	(2,004.32)	(38,650.90)	3.87
2003	(33.49)	(1,793.20)	302.38	(1,701.94)	(43,660.07)	4.37
2004	5.78	(1,787.42)	535.33	(1,166.61)	(48,679.17)	4.87
2005	34.91	(1,752.51)	1,055.62	(110.99)	(53,706.01)	5.38
2006	80.11	(1,672.40)	1,298.56	1,187.57	(58,735.03)	5.88
2007	97.69	(1,574.70)	1,572.91	2,760.49	(63,781.67)	6.39

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG7 - Centralized Study Program 7

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Inc.	15,922.18						
	Cust. Nonelec. Bill Inc.	0.00						
	Cust. O&M Cost Inc.	0.00					0.00	0.00
	Cust. Cap. Invest. Inc.	14,274.20					11,734.84	13,557.28
	Cust. Other Costs Inc.	0.00					0.00	0.00
	Cust. Rebates Paid							
	Cust. Income Tax Inc.							
	DS Revenue Dec.							
	DS Elec. Acq. Cost Inc.		7,131.67		7,131.67			
C	DS Nonelec. Revenue Dec.				0.00			
	DS Nonelec. Acq. Cost Inc.		0.00		0.00			
O	DS Rebates Paid		3,568.55		3,568.55			
	DS Cap. Rebates Paid		0.00		0.00			
S	DS Admin. Cost Inc.		3,074.44		3,074.44		2,661.20	3,074.44
	DS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
T	DS Sales Tax Cost Inc.		0.00		0.00		0.00	
	PS Revenue Dec.							
S	PS Elec. Prod. Cost Inc.			2,115.06		2,115.06	2,115.06	2,557.22
	PS Nonelec. Revenue Dec.							
	PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
	PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
	PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
	PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
	PS Rebates Paid			3,088.89		3,088.89		
	PS Cap. Rebates Paid			0.00		0.00		
	PS Admin. Cost Inc.			295.68		295.68	295.68	341.59
	PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
	Nonelec. Acq. Cost Inc.						0.00	0.00
	Internal Environmental Cost							
	External Environmental Cost							255.72

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG7 - Centralized Study Program 7

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.							
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	7,137.10						
B	DS Revenue Inc.				15,122.72			
	DS Elec. Acq. Cost Dec.							
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.					5,686.48		
I	PS Elec. Prod. Cost Dec.							
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							
	Total Costs	30,196.38	13,774.67	5,499.62	13,774.67	5,499.62	16,806.77	19,786.27
	Total Benefits	7,137.10	0.00	0.00	15,122.72	5,686.48	0.00	0.00
	Net Benefits	(23,059.28)	(13,774.67)	(5,499.62)	1,348.06	186.86	(16,806.77)	(19,786.27)
	Levelized Costs	3,248.68	1,481.95	686.59	1,481.95	686.59	2,098.20	2,128.70
	Levelized Benefits	767.84	0.00	0.00	1,626.98	709.91	0.00	0.00
	Levelized Costs ($/kWh)	(115.0747)	(0.0525)	(0.0255)	(0.0525)	(0.0255)	(0.0778)	(0.0916)
	Levelized Benefits ($/kWh)	(27.1986)	0.0000	0.0000	(0.0576)	(0.0263)	0.0000	0.0000
	Levelized Costs ($/kW)	##.##	524.37	254.43	524.37	254.43	777.53	915.37
	Levelized Benefits ($/kW)	271,693.56	0.00	0.00	575.69	263.07	0.00	0.00
	Benefit/Cost Ratio	0.24	0.00	0.00	1.10	1.03	0.00	0.00

EPRI DSManager

Page: 1
Date:03/31/95
Time:08:42:23

Meade County Rural Electric Coop Corp.

Demand-Side Management Plan

Plan: CEN_PRG8 - Centralized Study Program 8

START YEAR	END YEAR	PROGRAM NAME	PROGRAM DESCRIPTION
1994	2007	R_GR_HPR	Res-Green River-Spc Cnd-ASHP Replacement
1994	2007	R_HU_HPR	Res-Hend Union-Spc Cnd-ASHP Replacement
1994	2007	R_JP_AHR	Res-Jackson-ASHP Replacement
1994	2007	R_MC_HPR	Res-Meade Cty-Space Con-ASHP Replacement

EPRI DSManager

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG8 - Centralized Study Program 8

YEARLY STATISTICS

YEAR	BASE REVENUE LOST ('000 $)	F.C.A. REVENUE LOST ('000 $)	PRODUCTION COST SAVINGS ('000 $)	NONELEC REVENUE ('000 $)	INCREASE IN NONELEC AQUIS COST ('000 $)
1994	0.00	0.00	0.00	0.00	0.00
1995	(71.05)	0.00	(52.42)	0.00	0.00
1996	(171.91)	0.00	(121.95)	0.00	0.00
1997	(286.32)	0.00	(190.48)	0.00	0.00
1998	(515.48)	0.00	(256.27)	0.00	0.00
1999	(935.89)	0.00	(327.79)	0.00	0.00
2000	(1,624.25)	0.00	(408.89)	0.00	0.00
2001	(2,066.43)	0.00	(467.78)	0.00	0.00
2002	(2,547.16)	0.00	(533.38)	0.00	0.00
2003	(2,716.66)	0.00	(579.47)	0.00	0.00
2004	(3,293.08)	0.00	(636.34)	0.00	0.00
2005	(4,154.16)	0.00	(677.68)	0.00	0.00
2006	(4,757.64)	0.00	(738.77)	0.00	0.00
2007	(5,374.61)	0.00	(769.57)	0.00	0.00

Plan: CEN_PRG8 - Centralized Study Program 8

YEARLY STATISTICS

YEAR	NON CAP. ADMIN COST ('000 $)	CAPITALIZED ADMIN COST ('000 $)	NON CAP. REBATES PAID ('000 $)	CAPITALIZED REBATES PAID ('000 $)	GENERATION CAPACITY SAVINGS ('000 $)	TRANSMISSION CAPACITY SAVINGS ('000 $)	DISTRIBUTION CAPACITY SAVINGS ('000 $)
1994	0.00	0.00	0.00	0.00	0.00	0.00	0.00
1995	34.59	0.00	27.80	0.00	0.00	0.00	0.00
1996	48.16	0.00	38.70	0.00	0.00	0.00	0.00
1997	53.88	0.00	43.30	0.00	0.00	0.00	0.00
1998	53.94	0.00	43.35	0.00	0.00	0.00	0.00
1999	53.94	0.00	43.35	0.00	0.00	0.00	0.00
2000	53.94	0.00	43.35	0.00	0.00	0.00	0.00
2001	54.07	0.00	43.45	0.00	0.00	0.00	0.00
2002	54.07	0.00	43.45	0.00	0.00	0.00	0.00
2003	54.07	0.00	43.45	0.00	0.00	0.00	0.00
2004	54.13	0.00	43.50	0.00	0.00	0.00	0.00
2005	54.13	0.00	43.50	0.00	0.00	0.00	0.00
2006	54.26	0.00	43.60	0.00	0.00	0.00	0.00
2007	54.32	0.00	43.65	0.00	0.00	0.00	0.00

Big Rivers Electric Corporation

Power Supplier Summary Report

Plan: CEN_PRG8 - Centralized Study Program 8

YEARLY STATISTICS

YEAR	NET SAVINGS W/O REV. ('000 $)	CUMULATIVE SAVINGS W/O REV. ('000 $)	NET SAVINGS W/ REV. ('000 $)	CUMULATIVE SAVINGS W/ REV. ('000 $)	PRODUCTION SAVINGS (MWh)	PEAK LOAD REDUCTION (MW)
1994	0.00	0.00	0.00	0.00	0.00	0.00
1995	(9.98)	(9.98)	(43.76)	(43.76)	(4,533.53)	0.14
1996	35.10	25.12	(36.90)	(80.66)	(10,807.58)	0.32
1997	93.30	118.42	(1.34)	(82.01)	(17,781.21)	0.50
1998	158.98	277.39	161.91	79.91	(24,765.23)	0.69
1999	230.50	507.89	510.80	590.71	(31,749.31)	0.88
2000	311.60	819.49	1,118.06	1,708.77	(38,735.38)	1.07
2001	370.26	1,189.75	1,501.14	3,209.91	(45,740.30)	1.25
2002	435.86	1,625.61	1,916.26	5,126.17	(52,745.28)	1.44
2003	481.95	2,107.57	2,039.67	7,165.83	(59,752.24)	1.63
2004	538.70	2,646.27	2,559.11	9,724.94	(66,767.66)	1.82
2005	580.05	3,226.32	3,378.85	13,103.80	(73,785.07)	2.01
2006	640.92	3,867.23	3,921.02	17,024.81	(80,802.48)	2.20
2007	671.60	4,538.83	4,507.08	21,531.89	(87,830.34)	2.39

EPRI DSManager

Big Rivers Electric Corporation

Least Cost Planning Benefit/Cost Matrix

Plan: CEN_PRG8 - Centralized Study Program 8

PERSPECTIVES	PARTICIPANT TEST	OS UTILITY TEST	PS UTILITY TEST	OS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
Cust. Elec. Bill Inc.	22,637.56						
Cust. Nonelec. Bill Inc.	0.00						
Cust. O&M Cost Inc.	0.00					0.00	0.00
Cust. Cap. Invest. Inc.	731.06					568.37	658.36
Cust. Other Costs Inc.	0.00					0.00	0.00
Cust. Rebates Paid							
Cust. Income Tax Inc.							
OS Revenue Dec.							
OS Elec. Acq. Cost Inc.		15,204.95		16,204.95			
OS Nonelec. Revenue Dec.				0.00			
OS Nonelec. Acq. Cost Inc.		0.00		0.00			
OS Rebates Paid		365.53		365.53			
OS Cap. Rebates Paid		0.00		0.00			
OS Admin. Cost Inc.		4,093.93		4,093.93		3,534.31	4,093.93
OS Cap. Admin. Cost Inc.		0.00		0.00		0.00	0.00
OS Sales Tax Cost Inc.		0.00		0.00		0.00	
PS Revenue Dec.							
PS Elec. Prod. Cost Inc.			2,876.36		2,876.36	2,876.36	3,483.12
PS Nonelec. Revenue Dec.							
PS Nonelec. Acq. Cost Inc.			0.00		0.00	0.00	0.00
PS Gen. Cap. Debit			0.00		0.00	0.00	0.00
PS Trans. Cap. Debit			0.00		0.00	0.00	0.00
PS Dist. Cap. Debit		0.00		0.00		0.00	0.00
PS Rebates Paid			315.56		315.56		
PS Cap. Rebates Paid			0.00		0.00		
PS Admin. Cost Inc.			392.69		392.69	392.69	454.87
PS Cap. Admin. Cost Inc.			0.00		0.00	0.00	0.00
Nonelec. Acq. Cost Inc.						0.00	0.00
Internal Environmental Cost							
External Environmental Cost							348.31

Least Cost Planning Benefit/Cost Matrix

Program: CEN_PRG8 - Centralized Study Program 8

	PERSPECTIVES	PARTICIPANT TEST	DS UTILITY TEST	PS UTILITY TEST	DS RATEPAYER IMPACT TEST	PS RATEPAYER IMPACT TEST	TOTAL RESOURCE TEST	SOCIETAL TEST
	Data discounted to 1994	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)	('000 $)
	Discount Rates	6.00%	6.00%	8.50%	6.00%	8.50%	8.50%	6.00%
	Cust. Elec. Bill Dec.							
	Cust. Nonelec. Bill Dec.							
	Cust. O&M Cost Dec.							
	Cust. Cap. Invest. Dec.							
	Cust. Other Costs Dec.							
	Cust. Income Tax Dec.	0.00					0.00	
	Cust. Rebates Rec'ved	731.06						
B	DS Revenue Inc.				20,388.03			
	DS Elec. Acq. Cost Dec.							
E	DS Nonelec. Revenue Dec.							
	DS Nonelec. Acq. Cost Dec.							
N	DS Rebates Rec'ved							
	DS Cap. Rebates Rec'ved							
E	DS Admin. Cost Dec.							
	DS Cap. Admin. Cost Dec.							
F	DS Sales Tax Cost Dec.							
	PS Revenue Inc.					13,021.28		
I	PS Elec. Prod. Cost Dec.							
	PS Nonelec. Revenue Inc.					0.00		
T	PS Nonelec. Acq. Cost Dec.							
	PS Gen. Cap. Credit							
S	PS Trans. Cap. Credit							
	PS Dist. Cap. Credit							
	PS Rebates Rec'ved							
	PS Cap. Rebates Rec'ved							
	PS Admin. Cost Dec.							
	PS Cap. Admin. Cost Dec.							
	Nonelec. Acq. Cost Dec.							
	Internal Environmental Ben.			0.00		0.00	0.00	0.00
	External Environmental Ben.							
	Total Costs	23,368.62	20,664.41	3,584.61	20,664.41	3,584.61	7,371.73	9,038.59
	Total Benefits	731.06	0.00	0.00	20,388.03	13,021.28	0.00	0.00
	Net Benefits	(22,637.56)	(20,664.41)	(3,584.61)	(276.38)	9,436.67	(7,371.73)	(9,038.59)
	Levelized Costs	2,514.11	2,223.18	447.51	2,223.18	447.51	920.30	972.42
	Levelized Benefits	78.65	0.00	0.00	2,193.44	1,625.61	0.00	0.00
	Levelized Costs ($/kWh)	(65.6717)	(0.0581)	(0.0123)	(0.0581)	(0.0123)	(0.0252)	(0.0309)
	Levelized Benefits ($/kWh)	(2.0545)	0.0000	0.0000	(0.0573)	(0.0445)	0.0000	0.0000
	Levelized Costs ($/kW)	##.##	2,110.35	445.07	2,110.35	445.07	915.28	1,122.24
	Levelized Benefits ($/kW)	74,659.38	0.00	0.00	2,082.13	1,616.73	0.00	0.00
	Benefit/Cost Ratio	0.03	0.00	0.00	0.99	3.63	0.00	0.00

15

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 15) The first two paragraphs under "Load Growth Options" on page IV-5 discuss programs that would provide financial incentives to encourage member/customers to switch from natural gas furnaces and water heaters to their electric counterparts.

a. Please define and explain what the IRP means by "market transformation" in this context.

b. If such a fuel-switching incentive program were to be instituted for a number of years (with some measurable effect on the market) and were then terminated, would Big Rivers expect member/customers to continue purchasing electric space and water heating appliances in the absence of the incentives?

Response) a. Market transformation is the process by which consumer purchases of a particular type of appliance make it the dominant commodity. This "transforms" the market by reducing the number of available options to all customers in a region. An example might be the Appliance Efficiency Program instituted by the City of Austin, Texas in the 1980's. Over the years, more than 198,000 residential HVAC units were sold through this program. Because of the program's impact, local vendors stocked units with SEER values of 12 and above. Less efficient, lower priced units provided such little demand that they literally became scarce in the marketplace.

b. It is conceivable that such a market transformation might take place as a result of such a program. Customer convenience, electric rates and gas prices will all affect the final outcome of this process.

Witness) Armando de Leon
Burns & McDonnell

16

Item 16) a. Which cost effectiveness test (e.g., TRC, RIM, UC or PC) is being referenced in the last paragraph on page IV-5?

b. The same paragraph refers to a "preliminary analysis." Please provide a copy of this analysis, including any working papers.

Response) a. The utility test (UC) is being referenced in section IV-5.

b. The preliminary analysis was a comparison of the benefit costs as outlined in the R. W. Beck study of 1995, with corresponding data representative of Big Rivers' energy and capacity costs in 1999. Given that most programs were not cost effective in 1995 when energy and capacity costs were significantly higher than at present, Burns & McDonnell reviewed those few programs found to be cost-effective in 1995, reviewed Big Rivers' current costs and situation and established that those marginally cost effective programs would fail to be cost effective in the current situation. Please refer to Big Rivers response to the Division of Energy's first request for information Item No. 14 for the relevant work papers.

Witness) Armando de Leon
Burns & McDonnell

17

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 17) Which cost effectiveness test is being referenced in the last paragraph on page IV-11?

Response) The utility test is being referenced in the last paragraph on page IV-11.

Witness) C. William Blackburn

18

Item 18) Does Big Rivers or its member distribution cooperatives presently have any programs to promote improved energy efficiency among their member/customers? If so, please describe these programs, including quantitative information about their energy impacts if available.

Response) There are no demand-side management goal-oriented incentive programs at any of the distribution cooperatives or at Big Rivers to promote energy efficiency. Each cooperative provides energy efficiency advice to customers on a one-on-one basis.

Specific energy efficiency programs are offered for commercial and industrial customers to assist them with evaluating procedures and equipment to improve their efficiency and more effectively use energy in their facility. These services are performed and coordinated by the Commercial and Industrial (C/I) Services Advisor and are available to any C/I customer of Kenergy, Jackson Purchase or Meade County RECC.

- Energy use assessments evaluate the current energy use for a process or facility to determine if energy efficiency can be improved through a change of equipment.

- Operation assessments consider the energy use patterns for a facility or process to assist the customer to optimize their energy use with regard to the cost.

- Coordinated energy audits through the University of Louisville Industrial Assessment Center. The center will perform a comprehensive and confidential energy and waste assessment.

- Commercial & Industrial News is a quarterly publication produced by Big Rivers on behalf of its three member distribution cooperatives for all C/I customers which discusses electric utility issues and energy efficiency.

Information on energy efficiency for residential customers is promoted through direct customer contact and is soon to be available on various web sites sponsored by Big Rivers and its member cooperatives. Other programs and information available from one or more of Big Rivers' member distribution cooperatives are:

- Loan programs for weatherization and energy efficiency improvements;
- Written information on weatherization of residences;
- School programs on energy efficiency and safety;
- Advertising to promote weatherization; and
- Work with homebuilders on weatherization and energy efficient construction techniques.

Witness) Russ Pogue

19

Reorder No. 5109
JULIUS BLUMBERG, I
NYC 10013
®10% P.C.W.

Item 19) While Section IV of the IRP focuses on the effects of various types of DSM programs on the utility company, it does not appear to consider the question of which programs would be most beneficial to member/customers in terms of reduced energy bills.

a. In view of the fact that the purpose of a cooperative is to benefit its member/customers, why do the discussion and recommendations on pages IV-3 through IV-5 and pages IV-11 through IV-12 appear to leave the benefits for member/customers out of the analysis?

b. Why isn't the total resource cost (TRC) test used as a primary criterion for evaluating and comparing demand-side and supply-side resource options?

Response) Any program that can be considered beneficial to the customer and passing the participant test can and should be used by the customers as a means for reducing their overall energy bills. It is not in Big Rivers' or its members' best interest to increase revenue requirements and invest in programs that can become either "stranded" or "fleeting" investment.

a. Many DSM programs are beneficial to the customers. In the case of programs studied by R. W. Beck in 1995, and revisited by Burns & McDonnell in 1999, most of the conservation based programs were beneficial to the participant, but not so to Big Rivers. While Big Rivers and its members encourage customers to implement their own cost-savings initiatives, it is likewise the members responsibility to serve all ratepayers (RIM test) and implement programs that encourage rate reduction or rate stability in its respective service area.

b. The TRC is one of the criteria considered in evaluating demand- and supply-side options. In considering a utility's options, however, the utility test (UC) and all-ratepayers test (RIM) must also be considered. Programs that are not cost-effective to the participant are immediately discarded (since they would be difficult to sell and impractical to fund by individual customers). Many programs can have a positive TRC and poor RIM score.

Witness) Armando de Leon
Burns & McDonnell

20

Item 20) The provisions at the bottom of page IV-7 refer to load management contracts. The first provision would require the member/customer to agree to remain a customer for at least 7 years from the date of signing the contract. In view of the present status of the debate on electric industry restructuring, is it realistic to expect many customers to agree to this provision?

Response) Load Management contracts serve to preserve customer-utility partnerships and to benefit both throughout their duration. The customers benefit from reduced rates and additional services. The utility benefits because it retains customers and increases its optional resources and can increase revenues and maintain lower rates. Customers likewise benefit because they reduce their risk of increased rates and are remunerated financially when curtailed.

The program outlined in Appendix E is an interruptible rate schedule. Big Rivers has chosen to implement a curtailable rate schedule, which is a bit different. Burns & McDonnell recommends test marketing the contracting provisions before establishing them as a requirement.

Witness) Armando de Leon
Burns & McDonnell

21

BIG RIVERS ELECTRIC CORPORATION
RESPONSE TO THE KENTUCKY DIVISION OF ENERGY'S
FIRST REQUEST FOR INFORMATION OF MAY 18, 2000

CASE NO. 99-429

Item 21) Does Big Rivers plan to make any improvements to and/or more efficient utilization of its transmission and distribution (T&D) system during the 2000-2013 time frame? [Reference 807 KAR 5:058 Section 8(2)(a) and Section 5(4)]. If so, please provide a quantitative description and schedule of these improvements.

Response) Big Rivers' "Long Range Engineering Plan" for the period of 1995-2015 projected about $21 million of transmission improvements. Two of these projects were interconnections with other utilities. One interconnection, between Big Rivers and Kentucky Utilities, was completed September of 1997. The second was projected interconnection for 2010 and was between Big Rivers and East Kentucky Power. The plan has been modified to drop the East Kentucky interconnection, and in its place an interconnection with LG&E for the 2002-2003 time frame is being studied. The balance of the system improvements are improvements projected and contingent upon load growth predicted in Big Rivers' Power Requirements Study.

Witness) Travis Housley

22

Item 22) The method of local integrated resource planning (LIRP), as described in a strategic issues paper by E Source (1995) titled, "Local Integrated Resource Planning: A New Tool for a Competitive Era," is designed to determine if costs could be reduced by deferring transmission and distribution upgrades through the use of geographically-focused demand-side programs. [Other names for LIRP include "targeted area planning," "local area investment planning," "distributed resources planning," or "area wide asset and customer service."]

a. Has Big Rivers used the LIRP approach to determine whether any planned transmission or distribution projects could economically be deferred? If so, please provide the results of the studies.

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

Response) a. No, Big Rivers has not used the LIRP approach.

b. No, Big Rivers presently has no plans to use the LIRP approach in the future.

Witness) C. William Blackburn and Travis Housley

23

CASE NO. 99-429

Item 23) Please provide a detailed description of the method Big Rivers and its member distribution cooperatives use to determine how much to charge a new residential, commercial, or industrial customer to hook up their building to the grid. Please explain why this particular method or formula was chosen.

Response) Big Rivers supplies wholesale electric power to its three member distribution cooperatives who in turn supply the retail electric requirements of its member consumers. Generally, the wholesale power furnished by Big Rivers and the retail power furnished by the distribution cooperatives is provided by tariff approved by the Kentucky Public Service Commission. Each tariff explains the charge to "hook up" the new residential, commercial, or industrial customer's service. The hook-up charge is typically a nonrecurring charge designed to recover the cost of connecting to the utility. Generally, the methodology used would be to determine the cost plus a contribution to overheads. Commission approval of the tariffs includes approval of each utility's methodology. A copy of page 3 of Big Rivers' tariff dealing with this issue is attached. Additionally, a copy of certain pages of Henderson Union Electric Cooperative Corporation's (a part of Kenergy Corp.) approved tariff is attached which describes the method used to charge retail customers for service hook-up. Big Rivers and each of its members' tariff can be found on the Commission's web site at http://www.psc.state.ky.us under "Tariff Library."

Witness) David A. Spainhoward

RULES AND REGULATIONS

2. Contract Demand:

Upon mutual agreement with Member, a Contract Demand may be established for certain customers.

3. Metering:

The Seller shall meter all power and energy at voltage as mutually agreed to with the Member. Meters and metering equipment shall be furnished, maintained and read or caused to be furnished, maintained and read by the Seller.

4. Electric Characteristics and Delivery Point(s):

Electric power and energy to be furnished hereunder shall be alternating current, three-phase, sixty Hertz. The Seller shall make and pay for all final connections between the systems of the Seller and the Member at the point(s) of delivery. The parties will specify the initial points of delivery, delivery voltages and capacity prior to the commencement of service hereunder. Additional points shall be agreed upon by the Seller and the Member from time to time.

5. Substations:

The Member shall install, own and maintain the necessary substation equipment at the point(s) of connection unless otherwise agreed to by Seller. The Seller shall own and maintain switching and protective equipment which may be reasonably necessary to enable the Member to take and use the electric power and energy hereunder and to protect the system of the Seller.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JUL 18 1998

PURSUANT TO 807 KAR 5:011.
SECTION 9 (1)
BY: Stephan O Bell
SECRETARY OF THE COMMISSION

HENDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

RULES AND REGULATIONS

undercharged, an additional debit adjustment will be made to the member's account.

(c) If the member fails to agree to the above arrangement, Henderson Union will remove the meter and service and make proper preparations for taking legal action.

5. CONTINUITY

Henderson Union shall diligently try to provide constant and uninterrupted supply of electric energy, but should supply fail or be interrupted through acts of God, the public enemy, by accident, strikes, labor troubles, by action of the elements, or by any other cause beyond the reasonable control of Henderson Union, Henderson Union shall not be liable therefor.

6. RELOCATION OF LINES BY REQUEST OF MEMBERS

Henderson Union's established lines will not be relocated unless the expense for moving and relocating is paid by the member, except in instances where it would be to the advantage of Henderson Union to make such relocation.

7. SERVICES PERFORMED FOR MEMBERS

Henderson Union's personnel are prohibited from making repairs, performing services to the member's equipment or property except in cases of emergency or to protect the public or member's person or property. When such emergency services are performed, the member shall be charged for such service at the rate of time and material.

Service Procedures

8. APPLICATION FOR SERVICE

(a) All applicants for electric service shall execute Henderson Union's form of Applications for Membership and Service in acknowledgment of the terms and conditions of electric service cited therein and grant, convey and/or provide to Henderson Union any and all necessary rights, privileges, permits and easements incidental to or connected with such electrical service before electric service is supplied.

(b) All applicants shall provide within thirty (30) working days prior to the date service is required certain load data information in order that adequate facilities may be installed for the new service.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Stephan O Bell
SECRETARY OF THE COMMISSION

DATE OF ISSUE November 18, 1997 DATE EFFECTIVE January 1, 1998
Month Day Year Month Day Year

ISSUED BY John West President & CEO P. O. Box 18, Henderson, KY 42420
John West Title Address

For All Territory Served

P.S.C. No. 10

Original Sheet No. 3

..ENDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

Canceling P.S.C. KY No. 9

Sheet No.

RULES AND REGULATIONS

9. MEMBERSHIP FEE

Pursuant to Henderson Union's bylaws, a membership fee of twenty-five dollars ($25.00) shall be paid by all new members. Membership fee shall be refunded when all financial obligations are satisfied or may be applied against any unpaid bill of the member upon termination of electric service. Service will not be made available to a former member until any previously existing indebtedness to Henderson Union has been satisfied.

10. MEMBER DEPOSIT

(a) Henderson Union may require from any member or applicant for service, regardless of customer class, a minimum cash deposit, letter of credit from a financial institution, surety or performance bond, prepaid budget billing amount, adequate financial statements or other suitable guaranty to secure payment of bills in an amount not to exceed 2/12th of the estimated annual bill of such member or applicant; except for members qualifying for service reconnection pursuant to 807 KAR 5:006, Section 15, Winter Hardship Reconnection. Service may be refused or discontinued for failure to pay the requested deposit. Interest, as prescribed by KRS 78.460, will be paid annually either by refund or credit to the member's bill, except that no refund or credit will be made if the member's bill is delinquent on the anniversary date of the deposit.

(b) Henderson Union may waive the required deposit if the member or applicant has an established reliable payment history with Henderson Union. If a deposit has been waived or returned and the member fails to maintain a satisfactory payment record, a deposit may then be required. Henderson Union may require a deposit in addition to the initial deposit if the member's classification of service changes or if there is a substantial change in usage. Upon termination of service, the deposit, any principal amounts, and any interest earned and owing will be credited to the final bill with any remainder refunded to the member.

(c) If a deposit is held longer that 18 months, the deposit will be recalculated at the member's request based on the member's actual usage. If the deposit on account differs from the recalculated amount by more than $10.00 for a residential member or 10 percent for a non-residential member, Henderson Union may collect any underpayment and shall refund any overpayment by check or credit to the member's bill. No refund will be made if the member's bill is delinquent at the time of the recalculation.

(d) Interest will be paid on all sums held on deposit at the rate of 6 percent annually beginning on the date of deposit. The interest accrued shall be applied as a credit to the customer's bill or paid to the customer on an annual basis. If interest is paid or credited to the customer's bill prior to twelve (12) months from date of deposit, the payment or credit shall be on a prorated basis. If

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

DATE OF ISSUE November 18, 1997 DATE EFFECTIVE January 1, 1998
Month Day Year PURSUANT TO 807 KAR 5:011, SECTION 9 (1) Month Day Year

ISSUED BY John West BY: Stephan Bell President & CEO P. O. Box 18, Henderson, KY 42420
John West Title Address

Item 23
4 of 17

..ENDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

RULES AND REGULATIONS

interest is not credited to the member's bill or paid to the member annually, interest will be computed by a method which will result in an amount no less than that obtained by using a middle course method between simple and compound interest in compliance with Commission order dated October 31, 1989 in Case No. 89-057. Interest on deposits computed in this manner will accrue until credited to the member's bill or paid to the member.

(e) Sign--in cases of sign lighting, if it is an established firm, no deposit of any nature will be required except membership fee.

11. DISTRIBUTION LINE EXTENSIONS

(1) Residential extensions. An extension of 1,000 feet or less of single phase line shall be made by Henderson Union from its existing distribution line without charge to a prospective member who shall apply for service to a permanent dwelling that is to be the principle place of residence. The Cooperative will extend up to an additional 500 feet without charge provided the member executes a minimum bill contract for a period of three (3) years for the cost of the additional extension. The "service drop" to customer premises from the distribution line at the last pole shall not be included in the foregoing measurements. (T)

(2) Other extensions.

(a) When an extension of Henderson Union's line to serve an applicant or group of applicants amounts to more than 1,500 feet per customer, Henderson Union shall require the total cost of the excessive footage over 1,500 feet per member to be deposited with Henderson Union by the applicant or applicants, based on the average estimated cost per foot of the total extensions. (T)

(b) Each member receiving service under such extension will be reimbursed under the following plan: Each year for a period of not less than ten (10) years, for which the purpose of this rule shall be the refund period, Henderson Union shall refund to the member or members who paid for the excessive footage the cost of 1,000 feet of the extension in place for each additional residence connected during the year whose service line is directly connected to the extension installed and not to extensions or laterals therefrom, but in no case shall the total amount refunded exceed the amount paid Henderson Union. After the end of the ten (10) year refund period, no refund will be made.

(c) For additional members connected to an extension or lateral from the distribution line, the utility shall refund to any member who paid for excessive footage the cost of

1,000 feet of line less the length of the lateral or extension.

(3) Real estate subdivisions. An applicant desiring an extension to a proposed real estate subdivision may be required to pay the entire cost of the extension. Each year, for a period of not less than ten (10) years, Henderson Union shall refund to the applicant who paid for the extension a sum equivalent to the cost of 1,000 feet of the extension installed for each additional member connected during the year, but in no case shall the total amount refunded exceed the amount paid to Henderson Union.

(4) Indeterminate Services. Extensions of electric service for other than residential shall be provided under conditions that will not seriously jeopardize the objectives of Henderson Union of providing electric service for residential members. These prospective members are usually speculative in nature, such as barns, grains bins, wells, feed lots, farrowing houses, etc. Service to these members may be provided under the following conditions:

(a) Single-phase service shall be provided without contribution or contract if only a service drop is required.

(b) If a primary extension is required, the applicant, if a property owner, shall sign a minimum bill contract for a three-year period equal to the cost of the extension. No work is to be completed until contract is executed by applicant. Energy purchased under these special contracts will apply to the special monthly minimum.

(c) Non-property owners and businesses of a speculative nature shall pay the estimated cost of construction before work begins and will not be refunded.

(d) If a primary extension over 1,000 feet is required , the applicant, if a property owner, may request to sign a minimum bill contract for a ten-year period equal to the cost of the extension. The property owner shall also be required to allow Henderson Union to file a declining lien on the property for the cost of the construction. No work is to be completed until Henderson Union and applicant execute a contract and the lien is recorded. Energy purchased under these special contracts will apply to the special minimum on a month-by-month basis.

(5) Nothing contained herein shall be construed as to prohibit Henderson Union from making extensions under different arrangements provided such arrangements have been approved by the Public Service Commission.

(6) Nothing contained herein shall be construed as to prohibit Henderson Union from making

at its expense greater extensions than herein prescribed, should its judgement so dictate, provided like free extensions are made to other members under similar conditions.

12. DISTRIBUTION LINE EXTENSIONS TO MOBILE HOMES

(1) All extensions of up to 150 feet from the nearest facility shall be made without charge.

(2) Extensions greater than 150 feet from the nearest facility and up to 300 feet shall be made provided the member shall pay Henderson Union a "member advance for construction" of fifty dollars ($50) in addition to any other charges required by the utility for all members. This advance shall be refunded at the end of one (1) year if the service to the mobile home continues for that length of time.

(3) For extensions greater than 300 feet and less than 1,000 feet from the nearest facility, the utility may charge an advance equal to the reasonable costs incurred by it for that portion of the service beyond 300 feet plus fifty dollars ($50). Beyond 1,000 feet, the extension policies set forth in 807 KAR 5:041, Section 11 shall apply.

(a) This advance shall be refunded to the member over a four (4) year period in equal amounts for each year the service is continued.

(b) If the service is discontinued for a period of sixty (60) days, or should the mobile home be removed and another does not take its place within sixty (60) days, or be replaced by a permanent structure, the remainder of the advance shall be forfeited.

(c) No refunds shall be made to any member who did not make the advance originally.

13. RIGHT OF ACCESS

Henderson Union's identified employee shall at all reasonable hours have access to meters, service connections and other property owned by it and located on member's premises for purposes of installation, maintenance, meter reading, operation, replacement or removal of its property at the time service is to be terminated. Any employee of the utility whose duties require him to enter the member's premises shall wear a distinguishing uniform or other insignia, identifying him as an employee of Henderson Union, or show a badge or other identification which will identify him as an employee of the utility.

14. NOTICE OF TROUBLE

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Stephan O Bell

-ENDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

RULES AND REGULATIONS

Member shall give immediate notice at the office of Henderson Union of any interruptions, or irregularities, or unsatisfactory service, and of any defects known to member. Henderson Union may at any time it deems necessary, suspend supply of electrical energy to any member or members for the purpose of making repairs, changes, or improvements upon any part of its system. Henderson Union shall make reasonable notice of such discontinuance to member.

15. MEMBERS'S REQUEST FOR TERMINATION OF SERVICE

Any member desiring service terminated or changed from one address to another shall give the utility three (3) working days' notice in person, in writing, or by telephone provided such notice does not violate contractual obligations or tariff provision. The member shall not be responsible for charges for service beyond the three (3) day notice period if the member provides reasonable access to the meter during the notice period. If the member notifies the utility of his request for termination by telephone, the burden of proof is on the member to prove that service termination was requested if a dispute arises.

16. RECONNECTION CHARGES

Henderson Union will make no charge for connecting service to the members's premises for the initial installation of service, or to the member's premises if the service has been destroyed by fire. When service has been terminated, or service is transferred to a new member, Henderson Union's representative shall read the meter at such premises. A service charge of $10.00 (ten dollars) will be made to new occupant for the reconnecting or transferring of such service. Service charge will be due and payable at time of connection or transfer, or upon notice of said charge. No meters shall be installed or reinstalled after working hours unless in the judgement of Henderson Union's manager there exist circumstances that will justify the additional expense. In these cases, a service charge of $35.00 (thirty-five dollars) will apply.

17. RESALE OF POWER BY MEMBERS

All purchased electric service used on the premises of the member shall be supplied exclusively by Henderson Union and the member shall not directly or indirectly sell, sublet, or otherwise dispose of the electric service of any part thereof.

18. SERVICE CHARGE

All service calls made by Henderson Union pertaining to the member's premises shall be charged at the rate of $10.00 (ten dollars) per call during normal working hours.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011
SECTION 9 (1)
BY: Stephan Bell
SECRETARY OF THE COMMISSION

DATE OF ISSUE November 18, 1997 DATE EFFECTIVE January 1, 1998
Month Day Year Month Day Year

ISSUED BY John West Item 23 President & CEO P. O. Box 18, Henderson, KY 42420
John West 8 of 17 Title Address

error is know to have existed. If the period during which the error existed cannot be determined with reasonable precision, the time period shall be estimated using such data as elapsed time since the last meter test, if applicable, and historical usage data for the member. If that data is not available, the average usage of similar member loads shall be used for comparison purposes in calculating the time period. If the member and Henderson Union are unable to agree on an estimate of the time period during which the error existed, the Public Service commission shall determine the issue. In all instances of member over billing, the member's account shall be credited or the over billed amount refunded at the discretion of the member within thirty (30) days after final meter test results. Henderson Union shall not require member repayment of any under billing to be made over a period shorter than a period coextensive with the under billing.

23. DISCONTINUANCE OF SERVICE BY HENDERSON UNION EC

Henderson Union will discontinue or refuse service without notice to a member or an applicant when a dangerous condition is found to exist on the member's or applicant's premises. Henderson Union may refuse or discontinue service to an applicant or member, after proper notice for failure to comply with its rules and regulations, when a member or applicant refuses or neglects to provide reasonable access to the premises, for fraudulent or illegal use of service, or for nonpayment of bills. If discontinuance is for nonpayment of bills, the member shall be given at least ten (10) days written notice separate from the original bill, and cut-off shall be effected not less than twenty-seven (27) days after the mailing date of the original bill unless prior to discontinuance, a residential member presents to Henderson Union a written certificate, signed by a physician, registered nurse, or public health officer, that such discontinuance will aggravate an existing illness or infirmity on the affected premises, in which case discontinuance may be effected not less than thirty (30) days from the date the utility notifies the member in writing of state and federal programs which may be available to aid in payment of bills and the office to contact for such possible assistance. The discontinuance of service by Henderson Union for any cause stated in this rule does not release the member of his obligation of all bills due. The termination date will not be affected by receipt of any subsequent bill.

The termination notice requirements of this subsection shall not apply if termination notice requirements to a particular member or members are otherwise dictated by the terms of a special contract between the utility and member.

24. THREE PHASE SERVICE

Members are required to negotiate a contract for all three-phase service except as otherwise provided herein. Term of contract is determined by amount of investment required.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011,
SECTION 9(1)
BY: Stephan Bell
SECRETARY OF THE COMMISSION

RULES AND REGULATIONS

25. ELECTRIC MOTORS

Any single-phase motor larger than 7 ½ horse power will not be permitted except by written permission of Henderson Union. Larger motors must be three phase.

26. PRIMARY METERING

At any time Henderson Union finds it more desirable, it may at its own option and expense install primary metering equipment. The member will own and operate all facilities past the metering point. A discount of $.50 per kW of Billing Demand will be applied to the monthly bill if consumer owns and maintains all facilities beyond meter. (T)

27. EXTENSIONS TO UNDERGROUND SERVICE

Henderson Union will extend underground facilities to areas which physically and economically lend themselves to this type of service under the following terms and conditions which insure adequate service and safety to all persons engaged in the construction, maintenance, operations, or use of underground facilities and to the public in general. The terms and conditions also reflect and protect the rate payers who are served with overhead facilities from subsidizing those served with higher cost underground facilities and in general requires the reimbursement of the cost difference between overhead and underground facilities necessary to serve a given load requirement.

1. Definitions

The following words and terms when used in these rules and regulations have the meaning indicated:

(a) Applicant
The developer, builder or other person, partnership, association, corporation or governmental agency applying for the installation of an underground electric distribution system.

(b) Building
A structure enclosed within exterior walls or fire walls, built, erected, and framed of component structural parts and designed for less than five (5) family occupancy.

(c) Multiple-Occupancy Building
A structure enclosed within exterior walls or fire walls, built, erected and framed of

component structural parts and designed to contain five (5) or more individual dwelling units.

(d) Plant, Store, Warehouse, Commercial, School, Church, Community Building, Industrial, etc.
A structure (or structures) other than residential occupancy where power is used for any type of service classification other than residential.

(e) Distribution System
Electric service facilities consisting of primary and secondary conductors, transformers, and necessary accessories and appurtenances for the furnishings of electric power at utilization voltage.

(f) Subdivisions
The tract of land which is divided into ten (10) or more lots for the construction of new residential buildings, or the land on which is constructed two (2) or more new multiple occupancy buildings.

(g) Individual Service
Any service resulting in only one metering point on a permanent type building used as a residence.

(h) Indeterminate Service
Includes service to mines, quarries, oil wells, industrial and commercial enterprises of speculative purposes, seasonal use of any type, real estate subdivision, development of property for sale, enterprises where the applicant will not be the user of service, where there is little or no demand for service, tenant house, seasonal cabins, rental property and to barns, wells, and other service where the amount of permanency of service cannot be reasonably assured.

(I) Trenching & Backfilling
Opening and preparing the ditch for the installation of conductors including placing of raceways under roadways, driveways, or paved areas; providing a sand bedding below and above conductors when required; and backfill of trench to ground level. Minimum depth 48" primary, 4" secondary.

2. Rights-of-Way & Easements

(a) Henderson Union shall construct, own, operate, and maintain distribution lines

HENDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

RULES AND REGULATIONS

only along easements, public streets, roads, and highways which are legal right accessible to the utility's equipment and which the utility has the legal right to occupy, and on the public lands and private property across which rights-of-way and easements satisfactory to Henderson Union are provided without cost or condemnation by Henderson Union.

(b) Obtaining easements and rights-of-way necessary to extend service is the responsibility of Henderson Union. Henderson Union shall not require a prospective customer to obtain easements or rights-of-way on property not owned by the prospective customer as a condition of providing service. The cost of obtaining easements or rights-of-way shall be included in the total per foot cost of an extension, and shall be apportioned among the utility and customer in accordance with the applicable extension regulation.

(c) Rights-of-way and easements suitable to Henderson Union at the underground distribution facilities must be furnished by the Applicant in reasonable time to meet service requirements. The Applicant shall make the area in which the underground distribution facilities are to be located accessible to Henderson Union's equipment, remove all obstructions from such area, stake to show the property lines and final grade, and maintain clearing and grading during construction by Henderson Union. Suitable land rights shall be granted to Henderson Union obligating the Applicant and subsequent property owners to provide continuing access to the utility for operation, maintenance or replacement of its facilities, and to prevent any encroachment in the utility's easement or substantial changes in grade or elevation thereof.

(d) Where not feasible to trench under roads, highway, railroads, lakes, streams, etc., Henderson Union shall have the right to place this portion overhead with the granting of easements (at no cost to Henderson Union) for such overhead construction.

3. <u>Installation of Underground Distribution System - Subdivisions</u>

(a) Where appropriate contractual arrangements have been made, Henderson Union shall install within the subdivision an underground electric distribution system of sufficient capacity and suitable materials which, in its judgement, will assure that the property owner(s) will receive safe and adequate electric service for the foreseeable future.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011
SECTION 9 (1)
BY: Stephan D Bell
SECRETARY OF THE COMMISSION

DATE OF ISSUE November 18, 1997 (Month Day Year) DATE EFFECTIVE January 1, 1998 (Month Day Year)

ISSUED BY John West (signature) — John West, President & CEO (Title), P. O. Box 18, Henderson, KY 42420 (Address)

Item 23

.-NDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

RULES AND REGULATIONS

(b) All single phase conductors installed by the utility shall be underground. Appurtenances such as transformers, pedestal-mounted terminals, switching equipment and meter cabinets shall be placed above ground.

(c) Multi-phase primary mains or feeders required within a subdivision to supply local distribution or to service individual multi-phase loads may be overhead unless underground is required by governmental authority or chosen by the Applicant, in either of which case the differential cost of underground shall be borne by the Applicant.

(d) If the Applicant has complied with the requirements herein and has given Henderson Union not less than 10 days written notice prior to the anticipated date of the completion (i.e., ready for occupancy of the first building) in the subdivision, Henderson Union shall complete the installation 30 days prior to the estimated completion dates. (Subject to weather and ground conditions and availability of materials and barring extraordinary or emergency circumstances beyond the reasonable control of Henderson Union.) However, nothing in this policy shall be interpreted to require Henderson Union to extend service to portions of the subdivision not under active development.

(e) A non-refundable payment shall be made by the Applicant equal to the difference between the cost of providing underground facilities and that of providing overhead facilities. The payment to be made by the Applicant shall be determined from the total footage of single-phase primary, secondary, and service conductor to be installed at an average per foot cost differential in accordance with the Average Cost Differential filed herewith as Exhibit "A", which Average Cost Differential shall be updated annually as required by order dated February 2, 1973 of the Public Service Commission of Kentucky in Administrative Case No. 146. (Three (3) wire secondary and service conductor runs shall be considered as one conductor, i.e., triplex). The average cost differential per foot, as stated, is representative of construction in soil free of rock, shale, or other impairments which are anticipated or encountered in construction, the actual increased cost of trenching and backfilling shall be borne by the Applicant.

(f) The Applicant may be required to deposit the entire estimated cost of the extension. If this is done, the amount deposited in excess of the normal charge for the underground extensions, as provided in paragraph "e" above, shall be refunded to the applicant over a ten (10) year period as provided in 807 KAR 5:041 Section 3.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
Y: Stephan O Bell
SECRETARY OF THE COMMISSION

DATE OF ISSUE November 18, 1997 DATE EFFECTIVE January 1, 1998
Month Day Year Month Day Year

ISSUED BY John West Item 23 President & CEO P. O. Box 18, Henderson, KY 42420
John West 13 of 17 Title Address

For All Territory Served

P.S.C. No. 10

Original Sheet No. 14

Canceling P.S.C. KY No. 9

Sheet No.

..ENDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

RULES AND REGULATIONS

(g) The Applicant may be required to perform all necessary trenching and backfilling in accordance with Henderson Union's specifications. Henderson Union shall then credit the applicant's cost in an amount equal to Henderson Union's normal cost for trenching and backfilling.

(h) Henderson Union shall furnish, install and maintain the service lateral to the Applicant's meter base except that the Applicant shall furnish and install proper size metal conduit from the meter base to two (2) feet below ground level. When conditions require it and at its discretion, Henderson Union will install twenty (20) foot section of proper size conduit (metal or PVC) from Applicant's below grade conduit termination, back toward source.

EXHIBIT "A"
INSTALLATION OF UNDERGROUND DISTRIBUTION SYSTEM-SUBDIVISIONS

Single Phase, Loop Feed

Estimated Cost per foot Underground	$6.60
Estimated Cost per foot Overhead	$3.20
Cost Differential per foot	$3.40

(I) Plans for the location of all facilities to be installed shall be approved by Henderson Union and the Applicant prior to construction. Alterations in plans by the Applicant will require additional cost of installation or construction shall be at the sole expense of the Applicant.

(j) Henderson Union shall not be obligated to install any facility within a subdivision until satisfactory arrangements for the payment of charges have been completed by the Applicant.

(k) The charges specified in these rules are based on the promise that each Applicant will cooperate with the utility in an effort to keep the cost of construction and installation of the underground electric distribution system as low as possible and make satisfactory arrangements for the payment of the above charges prior to the installation of the facilities.

All electrical facilities shall be installed and constructed to comply with the rules

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011
SECTION 9 (1)
BY: Stephan O Bell
SECRETARY OF THE COMMISSION

DATE OF ISSUE November 18, 1997 DATE EFFECTIVE January 1, 1998
Month Day Year Month Day Year

ISSUED BY John West Item 23 President & CEO P. O. Box 18, Henderson, KY 42420
John West 14 of 17 Title Address

RULES AND REGULATIONS

and regulations of the Public Service Commission, National Electric Safety Code, Henderson Union specifications, or other rules and regulations which may be applicable.

(m) Service pedestals and method of installation shall be approved by Henderson Union prior to installation.

(n) Henderson Union shall backfill only once and in the event of further settling or washing, the Applicant shall be responsible for all necessary additional backfilling.

(o) An additional $20.00 per linear trench foot shall be charged where extremely rocky conditions are encountered, such conditions being defined as limestone or other hard stratified material in a continuous volume of at least one cubic yard or more which cannot be removed using ordinary excavation equipment.

(p) In the event of a grade change which results in Henderson Union reburying or setting deeper any underground facility to maintain safety limits, the entire cost of such reburying or relocation shall be borne by Applicant.

(q) In unusual circumstances, when the application of these rules appears impracticable or unjust to either party, or discriminatory to other members, Henderson Union or Applicant shall refer the matter to the Commission for a special ruling or for the approval of special conditions which may be mutually agreed upon, prior to commencing construction.

4. Installation of Underground Facilities to Individual Service Delivery Points

(a) Where primary and secondary conductors are involved, Henderson Union shall estimate the cost to provide adequate service both overhead and underground, and the Applicant shall pay such difference in cost as a non-refundable contribution prior to the commencement of such construction.

(b) Where only secondary conductors are involved, Henderson Union shall install underground conductors as follows:

1. Where possible, Henderson Union will trench and backfill and install the secondary conductor, the Applicant shall pay three dollars and forty cents ($3.40) per underground cable foot (pole to meter) prior to the commencement of such construction.

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)
BY: Stephan Bell
SECRETARY OF THE COMMISSION

..:NDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

RULES AND REGULATIONS

5. Change from Overhead to Underground Facilities

Where an existing member requests underground facilities and is presently being served with adequate overhead facilities, then the entire cost of such change shall be borne by the Applicant as a non-refundable contribution prior to the commencement of such construction. The cost includes:

(a) Labor, material, and overhead charges for the new installation, $3.40 per underground cable foot. (Service only, pole to meter.)

6. Three Phase Requirements - Underground

Any member requiring three-phase loads which are to be served by URD cables shall be encouraged to install all three phase equipment rated for 120/208 or 277/480 volts. The transformer(s) are to be connected grd. wye - grd. wye to minimize the possibility of ferroresonance.

If the member insists on a voltage requiring a delta connected transformer, the member will be required to pay for the equipment required to avoid ferroresonance, such as (1) three phase OCB, (2) gang operated air break switch at riser pole, or (3) dummy loads.

28. BILLING

Notices of amounts due and payable are sent to members of Henderson Union using four cycle billing periods based on map location on member's account. Date of current billing, penalty, late notice, and disconnect are as follows:

Billing Cycle	Billing Date	Penalty Date	Late Notice	Disconnect For Nonpayment
1	1st	15th	20th	11 days after late notice date
2	8th	23rd	28th	11 days after late notice date
3	15th	30th	5th following month	11 days after late notice date
4	20th	5th following month	10th following month	11 days after late notice date

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE

JAN 01 1998

PURSUANT TO 807 KAR 5:011
SECTION 9 (1)
BY: Stephan O Bell
SECRETARY OF THE COMMISSION

DATE OF ISSUE November 18, 1997 DATE EFFECTIVE January 1, 1998
Month Day Year Month Day Year

ISSUED BY John West President & CEO P. O. Box 18, Henderson, KY 42420
John West Title Address

..ENDERSON UNION ELECTRIC
COOPERATIVE CORPORATION

RULES AND REGULATIONS

29. COLLECTION CHARGE

Should it become necessary for a representative of Henderson Union to call at the member's premises or other location for the purpose of collecting a delinquent account, a charge of $10.00 will be made to the member's account for the extra service rendered, due and payable at such time delinquent account is collected. Henderson Union will charge a collection charge only once in any bill period. If service is discontinued for nonpayment, an additional charge of $10.00 will be made for reconnecting service, due and payable at time of such reconnection.

30. RETURNED CHECK CHARGE

When a check is received in payment of a member's account and returned unpaid by a bank for any reason, such account, together with all others owed by the member shall be due and payable upon demand, and such member subject to discontinuance of service without further notice.

Henderson Union will assess a $10.00 handling fee for any check that is returned to Henderson Union from the member's bank for insufficient funds or any reason for nonpayment.

31. SPECIAL METER READING CHARGE

All meters with demand devices are read by a representative of Henderson Union.

Henderson Union utilizes a one-card system which includes the bill and the meter card. The bill/meter card is mailed monthly to all other members. Upon failure of a member to return the meter reading card for three consecutive months, Henderson Union shall have its representative read the member's meter and a service charge of $10.00 will be made for the extra service rendered. The service charge will be made to the member's account and will be due and payable upon notice of said charge. In the event that an error in meter reading should be made, then the member shall pay for that month an equal to approximately his average bill. The following month his bill shall be computed on the regular schedule prorated for two months, and the amount paid shall be credited.

32. MONITORING USAGE

The following procedure has been established for monitoring member usage so as to detect any unusual deviations in individual member usage and the reasons for such deviations:

(a) The computerized billing system is programmed to automatically alert Henderson Union to any member provided monthly meter readings which would cause KWH usage to be

PUBLIC SERVICE COMMISSION
OF KENTUCKY
EFFECTIVE
JAN 0 1 1998
PURSUANT TO 807 KAR 5:011,
SECTION 9 (1)