COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF BLUE GRASS ENERGY	)	
COOPERATIVE CORPORATION FOR A	)	
CERTIFICATE OF PUBLIC CONVENIENCE AND	)	**CASE NO.**
NECESSITY TO CONSTRUCT FACILITIES	)	**2011-00007**
ACCORDING TO THE APPLICANT'S 11/01/2010 ~	)	
10/31/2013 CONSTRUCTION WORK PLAN	)	

RESPONSE OF:

BLUE GRASS ENERGY COOPERATIVE, INC. ("BGE") TO THE

"FIRST INFORMATION REQUEST OF COMMISSION STAFF TO BGE"

FOR COMMISSION'S ORDER 2011-00007

DATED MAY 06, 2011

FILED: MAY 21, 2011

The Witnesses for All Response Contained Hereinafter:

Gary Grubbs, P.E. ~ Consulting Engineer for BGE

Chris Brewer ~ BGE

Ken Cooper ~ BGE

Donald Smothers ~ BGE

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VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JESSAMINE)

The undersigned, **Gary Grubbs**, being duly sworn, deposes and says that he is a Consulting Engineer for BGE, and that he has personal knowledge of the matters set forth in the response for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Gary Grubbs
Gary Grubbs

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17th day of May 2011.

Notary Public

(SEAL)

My Commission Expires:

September 11, 2012

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JESSAMINE)

The undersigned, **Chris Brewer**, being duly sworn, deposes and says that he is Vice-President, Engineering for BGE, and that he has personal knowledge of the matters set forth in the response for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Chris Brewer

Chris Brewer

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17th day of May 2011.

(SEAL)

Notary Public

My Commission Expires:

September 11, 2012

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) **SS:**
COUNTY OF JESSAMINE)

The undersigned, **Ken Cooper**, being duly sworn, deposes and says that he is Manager, Information Technology for BGE, and that he has personal knowledge of the matters set forth in the response for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

____
Ken Cooper

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 16th day of May 2011.

(SEAL)

____
Notary Public

My Commission Expires:

September 11, 2012

VERIFICATION

COMMONWEALTH OF KENTUCKY)) SS: COUNTY OF JESSAMINE)

The undersigned, **Donald Smothers**, being duly sworn, deposes and says that he is Vice President, Financial Services and CFO for BGE, and that he has personal knowledge of the matters set forth in the response for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Donald Smothers

Donald Smothers

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 17th day of May 2011.

Notary Public

(SEAL)

My Commission Expires:

September 11, 2012

BLUE GRASS ENERGY COOPERATIVE, INC.

CASE NO. 2011-00007

Response to Commission Staff's First Data Request
Dated May 06, 2011

Question No. 1

Witness: Chris Brewer

Q1. Refer to Executive Summary of the 2010-2013 Construction Work Plan ("CWP"), Section I.A. – Purpose, Results and General Basis of Study. This section states the "2013 projected number of consumers and total peak system load were taken directly from the Cooperative's 2010 Load Forecast Report (LFR) as approved by RUS."

a. Provide a copy of the Rural Utilities Services ("RUS") approval of Blue Grass Energy's 2010 LFR.

b. Provide a copy of Blue Grass Energy's 2010 LFR.

A1.

a. A copy of the approval by RUS is included as page 44 of the LFR (page 73 of the electronic filling) and SEC Board Approval on page 45 (page 74 of the electronic filing).

b. Blue Grass Energy's 2010 LFR is included as <u>Exhibit 1</u>

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 2

Witness: Donald Smothers (2. & b. & c.)
Chris Brewer (2.a.)

Q2. Refer to the Executive Summary of the 2010-2013 CWP, Section I.E. – Summary of Construction Program and Costs. Is the annual total for distribution plant additions and replacements known for 2010? If yes, provide that total.

a. The annual cost for distribution plant additions and replacements from 2001 through 2009 was $9,620,340. The average annual cost for distribution plant changes for the 2010-2013 CWP is $12,663,900, which represents a 32 percent increase from the average annual plant additions for the 2001 through 2009 period. The instant [sic] CWP states that capital expenditures for 2010-2013 have increased over past plant expenditures, "due to material price increases and system improvement increases." Provide specific examples of the "material price increases" and explain what is meant by the phrase "system improvement increases".

b. For the 2010-2013 CWP, approximately 76 percent of the proposed expenditure is for new construction and 24 percent is for system improvements. For each of the previous five years, provide a breakdown of the capital expenditures for new construction and for system improvements.

c. Refer to the final paragraph of this section regarding the eligibility for RUS loan funds and Exhibit 2, Cost of Operations. Does Blue Grass Energy anticipate the interest rate on the RUS loan to be four percent?

A2. Yes, $12,381,438

a. The phrase "system improvement increases" was included to indicate an increase in projects of this type. The 2011/13 CWP was developed using BGE's new GIS/Mapping database and Milsoft WindMil™ models that provided a more-detailed analysis of the distribution system. This "more-detailed analysis" of the system inherently included several additional system improvement projects that required attention.

Material Item	2004 Cost ($)	2011 Cost ($)	% Incr
1/0 URD Primary Conductor	$1.22 / Ft	$2.32 / Ft	13 % / Yr
5/8" X 10" Machine Bolt	$0.64 / Ea	$1.10 / Ea	10 % / Yr
15 KVA Pole Mount Transformer	$423 / Ea	$745 / Ea	11 % / Yr
25 KVA Pole Mount Transformer	$477 / Ea	$956 / Ea	14 % / Yr
25 KVA Pad Mount Transformer	$836 / Ea	$1,373 / Ea	9 % / Yr
350 MCM URD Triplex Cable	$1.60 / Ft	$2.20 / Ft	5 % / Yr
2/0 URD Triplex Cable	$0.70 / Ft	$0.98 / Ft	6 % / Yr
		Average:	10 %

b. For the 2010-2013 CWP the proposed expenditure for new construction is 32.3% not 76%. The five year breakdown of capital expenditures for new construction and for system improvements is as follows:

Year	New Construction	Special Equipment	System Improvements
2006	$4,593.009	$5,450,775	$3,477,118
2007	$5,320,375	$2,483,108	$1,955,907
2008	$4,101,670	$1,906,998	$5,938,639
2009	$3,203,425	$1,306,779	$5,598,208
2010	$4,115,638	$2,557,534	$6,083,447

c. The loan will be based on the RUS Federal Financing Bank (FFB) loan quarterly rates based on the date the loan requisition is processed. Currently the rates are as follows as of May 11, 2011:

3 mo	**0.03%**
6 mo	**0.10%**
1-yr	**0.24%**
2-yr	**0.64%**
3-yr	**1.06%**
5-yr	**1.91**
7-yr	**2.52**
10-yr	**3.12**
20-yr	**3.82**
30-yr	**3.95**

Based on the historical low rates, we anticipate requesting the 30 year rate which is slightly below 4.0% as of May 11, 2011. However, our decision will be based on the rates in effect as of the date of the loan request.

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Question No. 3

Witness: Donald Smothers (3.)
Chris Brewer (3.a.)
Gary Grubbs (3.b.)

Q3. Refer to the Basis of Study and Proposed Construction section of the 2010-2013 CWP, Section II.C.1., Analysis of Current System Studies – 2010 Load Forecast (LF). Blue Grass Energy's 2010 Load Forecast projects a 2.5 percent annual growth in energy sales for the 2010-2013 period. Winter and summer peak KW demands were projected to grow approximately 2.1 percent and 2.3 percent, respectively, for the same time period. Provide the energy sales growth along with the winter and summer peak demand for the previous five years.

a. Refer to Section II.C.2., Analysis of Current System Studies – 2004 Long Range System Study ("LRSS"). Earlier in the 2010-2013 CWP, it was noted that Blue Grass Energy's 2004 LRSS load projections and recommendations were adequate for the 2010-2013 CWP. Provide a copy of the 2004 LRSS.

b. The 2010-2013 CWP notes that the "projected 2010 demand in the LF reflects a system growing slightly less than projected for 2010 in the LRSS. The current LRSS should be valid for recommendations over the next three years (2010-2013 CWP)." Explain in detail the basis for this statement.

A3.

Year	Sales Growth	Winter Peak (MW)	Summer Peak (MW)
2006	-0.9 %	298,632	248,251
2007	5.2 %	311,903	259,429
2008	0.8 %	355,080	237,708
2009	-5.9 %	350,916	231,039
2010	7.3 %	333,127	248,828

a. Blue Grass Energy's 2004 Long Range System Study, alternately referred to as the 2004 Long Range Plan ("LRP"), is included as Exhibit 2.

b. This statement is used to compare the system demand that was predicted in the 2004 LRP to the system demand predicted in the 2010 LF for the year of 2010. The demand predicted in the LF is somewhat lower (slightly less) than the demand that was predicted in the LRP for the year 2010. This illustrates that the future growth rate that was predicted for the system in 2004 has been less than expected. However, the fact that growth has not been as high as expected does not erase the validity of the LRP. The basis for the statement in question was to establish the fact that we feel the LRP is still valid despite the fact that growth has been less.

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 4

Witness: Chris Brewer

Q4. Refer to the 2008 Operations and Maintenance Survey (RUS Form 300) section of the 2010-2013 CWP, Section II.C.3., regarding items noted for improvement. Does Blue Grass Energy own all of the electric utility poles in its service area? If not, provide a list of other owners and the maintenance procedures on such poles.

A4. Blue Grass Energy owns the great majority of the poles in its electric service area. Other poles are owned by AT&T, Windstream and Cincinnati Bell. The other pole owners are responsible for the maintenance procedures of their poles in accordance with our joint use pole agreement in which the pole owners are responsible for maintaining the poles in a safe and serviceable condition in accordance with the requirements of the applicable Code.

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Question No. 5

Witness: Gary Grubbs

Q5. Refer to the Basis of Study and Proposed Construction section of the 2010-2013 CWP, Section II.D.1., Annual Consumer, Load, and Losses Data.

a. Blue Grass Energy's annual distribution system losses were noted to be 4.7 percent for 2009. Is "annual distribution system losses" synonymous with "system energy losses?"

b. If yes, Blue Grass Energy's 2009 distribution system losses, or system energy losses, of 4.7 percent is within the RUS established guidelines of 8.2 percent. Given the level of distribution system losses, explain the statement in paragraph 6 of the Application that the construction proposed in this CWP is needed, in part, to "reduce system energy losses."

A5.

a. Yes, the two terms are synonymous.

b. Reducing losses is usually not the primary objective for justification of a CWP construction item. However, it is an important secondary objective, and we feel that it is worth mentioning when it is applicable to a CWP item. Even if a system's losses are considered typical or better than average, reducing losses is

still desirable, because it reduces costs. This is beneficial to both the company and the member owners.

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 6

Witness: Chris Brewer (6. & b.)
Donald Smothers (6.a.)

Q6. Refer to the Required Construction Items section of the 2010-2013 CWP, Section III.A., Service to New Consumers. The CWP estimates that 2,550 underground and overhead services for new customers will be built for the three-year CWP period. Explain the derivation of the 2,550 figure and the amount of additions expected in each of the three years of the CWP.

a. Approximately 32.3 percent of the capital required for the CWP is estimated to be for new consumer services ($12,285,000 out of $37,991,700). For each of the past five years, provide the percentage of capital used for the new consumer services, including the dollar amounts for new consumer services and the total amount of capital for distribution plant changes.

b. Blue Grass Energy proposes to replace 600 poles each year for the three-year CWP period at a cost of $2,500 per pole. Explain how Blue Grass Energy arrived at the estimated pole cost.

A6. The number of new customers in the CWP is developed in consultation with the Rural Utilities Service General Field Representative. Historical numbers and projected growth are used in developing this figure. The RUS General Field Representative approves this figure when he approves the CWP.

a. The dollar amounts for new construction and plant changes are the same as 2b. The percentage for new services based on 2b for the past five years are:

2006	**34.0%**
2007	**54.5%**
2008	**34.3%**
2009	**31.7%**
2010	**32.3%**

b. As Exhibit B of the 2010/13 CWP shows, the initial cost for year 1 is based on an average of the preceding two years. The dollar figure for years two and three were increased by $75 per year to allow for inflation. This equates to an increase of approximately 3% per year.

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Question No. 7

Witness: Chris Brewer

Q7. Refer to the Required Construction Items section of the 2010-2013 CWP, Section III.H., Pole Replacements. It is noted that, Pursuant to RUS guidelines, Blue Grass Energy should inspect at least 10 percent of its system's total poles annually. Explain whether Blue Grass is complying with the RUS pole inspection recommendation.

A7. Blue Grass Energy is complying with the RUS recommendation of inspecting 10% of its poles annually.

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Question No. 8

Witness: Gary Grubbs

Q8. Refer to Section III.J., concerning the proposed changes to the two-way vehicle communication system. Explain what is meant by the phrase "FCC re-farming of BGE frequencies during the CWP period."

A8. "Re-farming" is the informal name of an FCC notice and comment rule-making proceeding (PR Docket No. 92-235) opened in 1992 to develop an overall strategy for using the spectrum in the private land mobile radio (PLMR) allocations more efficiently to meet future communications requirements. Re-farming changed the channel spacing in the 150 MHz-174 MHz VHF band and in the 450 MHz-512 MHz UHF band. Before re-farming, channels in the VHF band were spaced 15 kHz apart. As part of the re-farming effort, the FCC added a channel midway between the original channel centers, making post re-farming VHF channel spacing 7.5 kHz and, in effect, doubling the number of VHF channels. At UHF before re-farming, channels were spaced 25 kHz apart. The FCC wanted to quadruple the number of channels, so three channels were added between the original channel centers, thus making post re-farming UHF channel spacing 6.25 kHz

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Question No. 9

Witness: Ken Cooper

Q9. Refer to Section III.K., DA Backbone System. It is noted in this section that "BGE is currently in the process of installing a DA Backbone project for the purpose of precisely controlling switched capacitors, regulating VARs, regulating system voltage, and optimizing system conditions conducive to loss reduction and service quality."

a. Regarding the statement that Blue Grass Energy is "currently in the process of installing a DA Backbone project," provide the status of the installation of this project.

b. Has Blue Grass Energy conducted a cost-benefit analysis regarding this project?

c. If the response to 9.b. is no, fully explain why a cost-benefit analysis was not undertaken.

d. If the response to 9.b. is yes, provide the analysis and quantify the benefits to be achieved by this proposed project.

e. Refer to the total cost of Project Management, Setup and Implementation. Provide a breakdown of these costs and the basis for the determination of each basis for the determination of each.

A9.

a. The pilot Volt/VAR project in currently under construction at two (2) substations while the proposed DA Backbone project has not started.

b. No, not at this time

c. A cost benefit analysis has not been done, as part of the benefits of this project will be based on the results of our on-going Volt/VAR pilot project. Once these benefits are known we will complete a cost/benefit analysis. The estimated least cost alternatives were included within the 2010/2013 CWP to have funds available when project details are finalized.

d. N/A

e. Project Management, Setup and Implementation of Base Station

Gateway system:	**$227,000**
Propagation Study:	**$2,350**
Site Preparations:	**$21,300**
Tower Gateway Certification:	**$56,400**
Network Optimization:	**$17,650**
RNI Setup, Configuration & Commissioning:	**$5,900**
DA Hosted Software Setup, Config & Training:	**$8,125**
Project Management:	**$30,000**
BGE Personnel Management and Labor:	**$85,275**

These costs are based on vendor quotes and BGE costs.

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Question No. 10

Witness: Gary Grubbs

Q10. Refer to page 2 of Exhibit B. Explain how Blue Grass Energy arrived at the projected cost for each of the listed constructed types.

A10. These costs were projected based on engineering judgment – taking into account information from various industry sources. Since RUS only finances the actual cost of any project, it is not necessary for these projections to be exact, only reasonably accurate (ballpark) costs.

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 11

Witness: Chris Brewer

Q11. Refer to Exhibit C, Status of Previous 2007-2009 Work Plan Projects. Of the 59 projects listed in these two tables as being completed, 46 of the projects' actual costs exceeded their projected costs, with several projects going three or four times over their projected costs. For each of these projects, fully explain why the project's actual cost exceeded its projected cost.

A11. Line conversion projects can exceed their projected costs for a number of different reasons. Such reasons include increases in material costs, excessive right of way trimming, and relocating lines to allow for reduced future maintenance costs and improved reliability. Also, costs of projects will overlap to another project that is related, but would have a different code. Other reasons that projects can exceed projections is that once the field staking is started you may find additional lines and taps that need replacing that are not part of the original project and cannot be determined from the map. This type work is more economical to be done on the same work order as the original project rather than have another work order staked at a different time. RUS does not place a limit / cap on the cost of the individual projects, however the total value of the accompanying loan is fixed at the beginning of the work plan period.

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 12

Witness: Chris Brewer

Q12. Refer to Exhibit E, page 1. How did Blue Grass Energy arrive at the average cost of $4,818 for underground and overhead services for new customers?

A12. The cost for each year and the historical costs are shown on page 1 of Exhibit B of the 2010/13. These costs were grown by $150 per year to allow for inflation. This equates to an increase of approximately 3% per year. These figures are also developed in consultation with and approved by the RUS General Field Representative.

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 13

Witness: Ken Cooper

Q13. Refer to Exhibit E, page 2. Regarding RUS Ref. No. 601, what type of meters does Blue Grass Energy propose to install for new customers? How did Blue Grass Energy arrive at the average cost of $129 per meter?

A13. BGE uses AMR/AMI meters which are compatible with our current system. The average cost was calculated based on the following:

Meter	**$35.00**
AMR/AMI Module	**$66.50**
Installation Labor	**$27.50**
Total	**$129.00**

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 14

Witness: Chris Brewer

Q14. Refer to Exhibit I, Page 1. Has Blue Grass Energy received approval from East Kentucky Power Cooperative, Inc. ("EKPC") for the costs of the needed capacitors and racks? If so, provide confirmation of the approval and the amount of cost that EKPC will incur.

A14. Blue Grass Energy has not yet received approval on all of the capacitor banks from East Kentucky Power.

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 15

Witness: Gary Grubbs

Q15. Refer to Exhibit N, pages 1-3.

a. Provide an explanation of the basis of the 7.18 percent Cost of Capital, or Cost of Debt, listed on each page and an example of the [sic] how it is computed.

b. Provide the basis of the annual growth rate projected for peak demand and explain why it is the rates projected in Section II.C.1 and 2 [sic] of the CWP.

c. Provide the basis of the energy charge in dollars per kWh per month.

A15.

a. Exhibit N is a computer program that Patterson & Dewar uses to show typical ranges for conductor loading economics. The numbers used as inputs are typical for the "average" electric distribution cooperative and are not specific to BGE. This purpose of this exhibit is to show general ranges for which specific conductors are economical for most distribution cooperatives. Using conductor economic calculations for the selection of conductor size is seldom the most important factor to consider. Other factors such as: ties between substations, critical load transfers, specific circuit loading characteristics, etc. are the driving forces in conductor selection, and these are tempered with local input from the cooperative, taking into account specific system conditions.

b. Please refer to answer 15a above. The annual growth rate shown for projected peak demand is a typical growth rate for the average cooperative and not specific to BGE. The actual growth rate for BGE's winter system demand from the 2010 Load Forecast is approximately 2.2%.

c. Please refer to answer 15a above. The energy charge in dollars per kWh per month is not specific to BGE.

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Question No. 16

Witness: Chris Brewer

Q16. Refer to page 1 of Exhibit W. What is the projected decrease in line losses due to the installation of the DA backbone?

A16. There is no decrease in line losses directly related to the DA backbone project. Line loss reduction comes from the Volt/VAR application. The DA backbone will serve as a communications means for the Volt/VAR application.

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Question No. 17

Witness: Ken Cooper

Q17. Provide an update on the status of the TS-2 Automatic Meter Reading ("AMR") system that has been included in the work plans for 2004-2005.

a. Explain whether or not the system capabilities have been changed since the CPCN was issued for the CWP related to Case No. 2004-00251[1] for the Blue Grass Energy system.

b. Do these meters reflect the most current metering technology available on the market? If not, explain why Blue Grass Energy has decided on this particular technology.

A17. The BGE TS-2 system (AMR/AMI) installation has been completed as designed and certificated.

a. No substantial changes in system capabilities.

b. This technology was state-of-the-art when selected by BGE in 2004/05 and will make a good transition to newer technology when deemed necessary in the future.

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[1] Application of Blue Grass Energy Cooperative Corporation for a Certificate of Convenience and Necessity for its 2004 – 2005 Construction Work Plan (Ky. [sic] PSC, November 15, 2004).

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 18

Witness: Chris Brewer

Q18. Identify if there are any other additional costs in the 2010-2013 CWP associated with any Advanced Metering Infrastructure System, AMR, or Smart Grid activities.

A18. There are no additional costs in the 2010-2013 CWP other than the ones already listed / stated.

BLUE GRASS ENERGY COOPERATIVE, INC.

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Question No. 19

Witness: Ken Cooper

Q19. Has Blue Grass Energy contacted other electric utilities in Kentucky in order to determine what other AMR systems are in use and how they perform?

a. If no, explain why this has not been done.

b. If yes, provide the AMR technology in use and the name of the utility using it.

A19. No

a. We are not planning to implement a new AMR system, although we do continually monitor new AMR/AMI technologies used by others.

b. N/A

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Question No. 20

Witness: Gary Grubbs

Q20. Verify how the system Annual Load Factor currently remains at the 41.0 percent level and why it is expected to increase slightly in the future. Show all calculations.

A20. The annual load factor is the ratio of the average demand to the peak demand. Weather patterns play a significant role from year-to-year in influencing what the actual annual load factor will be. BGE's annual load factor has varied in recent years by more than 10% and weather is one of the most significant influences on this variation. Since weather patterns cannot be accurately predicted for the future, projections for load factor are based upon judgment. The slight increase shown for the future is very small and falls within the range of load factors experienced historically.

Blue Grass Energy Cooperative Corporation

2010 Load Forecast

Prepared by:
East Kentucky Power Cooperative, Inc.
Resource Planning Department

August 2010

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Introduction
Executive Summary

Blue Grass Energy Cooperative Corporation (Blue Grass Energy), located in Nicholasville, Kentucky, is an electric distribution cooperative that serves members in 23 counties. This load forecast report contains Blue Grass Energy's long-range forecast of energy and peak demand.

Blue Grass Energy and its power supplier, East Kentucky Power Cooperative (EKPC), worked jointly to prepare the load forecast. Factors considered in preparing the forecast include the national and local economy, population and housing trends, service area industrial development, electric price, household income, weather, and appliance efficiency changes.

EKPC prepared a preliminary load forecast, which was reviewed by Blue Grass Energy for reasonability. Final projections reflect a rigorous analysis of historical data combined with the experience and judgment of the President/CEO and staff of Blue Grass Energy. Key assumptions are reported beginning on page 18.

Executive Summary *(continued)*

The load forecast is prepared biannually as part of the overall planning cycle at EKPC and Blue Grass Energy. Cooperation helps to ensure that the forecast meets both parties' needs. Blue Grass Energy uses the forecast in developing three-year work plans, long-range work plans, and financial forecasts. EKPC uses the forecast in areas of marketing analysis, transmission planning, generation planning, demand-side planning, and financial forecasting.

The complete load forecast for Blue Grass Energy is reported in Table 1-1 on pages 8 and 9. Residential and commercial sales, total purchases, winter and summer peak demands, and load factor are presented for the years 1990 through 2030.

Table 1-1

Blue Grass Energy - 2010 Load Forecast

MWh Summary

Year	Residential Sales (MWh)	Small Comm. Sales (MWh)	Large Comm. Sales (MWh)	Public Street & Hwy. Lighting Sales (MWh)	Total Sales (MWh)	Office Use (MWh)	% Loss	Purchased Power (MWh)
1990	385,788	72,200	106,324	395	564,707	428	5.4	597,604
1991	422,686	65,729	129,330	402	618,146	455	5.9	657,500
1992	428,403	71,877	137,909	493	638,682	449	5.3	674,899
1993	469,900	75,852	150,928	588	697,268	501	6.0	742,421
1994	481,416	80,524	163,989	548	726,477	525	4.4	760,326
1995	507,435	77,613	182,296	512	767,857	750	6.0	817,922
1996	535,149	84,595	187,761	564	808,068	783	4.5	847,345
1997	544,423	89,185	198,176	588	832,372	764	5.5	881,949
1998	564,721	97,194	206,771	615	869,300	744	5.3	918,716
1999	597,111	107,096	226,725	641	931,573	772	4.8	979,348
2000	619,876	113,387	243,710	662	977,635	881	6.5	1,046,882
2001	660,667	113,469	251,384	754	1,026,274	890	3.2	1,060,783
2002	693,442	112,084	264,838	803	1,071,167	1,016	5.7	1,137,254
2003	706,842	110,316	266,767	823	1,084,749	995	4.7	1,138,813
2004	723,399	113,275	273,519	857	1,111,050	1,055	5.3	1,174,625
2005	787,002	117,057	282,109	888	1,187,056	1,039	4.4	1,242,479
2006	766,303	126,275	282,633	980	1,176,191	1,231	3.1	1,215,593
2007	816,735	134,477	285,115	1,034	1,237,361	1,561	5.5	1,310,866
2008	826,495	128,983	290,597	1,094	1,247,170	1,628	4.8	1,312,250
2009	782,891	105,622	283,583	1,134	1,173,230	1,534	4.7	1,232,819
2010	809,372	109,114	287,629	1,149	1,207,263	1,574	4.8	1,269,787
2011	817,746	112,154	294,273	1,194	1,225,368	1,574	4.8	1,288,805
2012	830,276	115,736	314,592	1,230	1,261,835	1,574	4.8	1,327,110
2013	839,997	119,753	336,923	1,266	1,297,940	1,574	4.8	1,365,036
2014	860,156	124,083	348,797	1,302	1,334,338	1,574	4.8	1,403,269
2015	880,261	128,624	357,789	1,338	1,368,012	1,574	4.8	1,438,641
2016	903,360	133,306	373,355	1,373	1,411,395	1,574	4.8	1,484,211
2017	925,781	138,082	380,315	1,409	1,445,587	1,574	4.8	1,520,127
2018	950,160	142,923	387,703	1,445	1,482,232	1,574	4.8	1,558,620
2019	975,986	147,809	394,930	1,481	1,520,207	1,574	4.8	1,598,509
2020	1,000,390	152,724	401,741	1,517	1,556,371	1,574	4.8	1,636,497
2021	1,025,561	157,653	407,223	1,552	1,591,990	1,574	4.8	1,673,912
2022	1,051,550	162,589	420,121	1,588	1,635,848	1,574	4.8	1,719,981
2023	1,078,825	167,527	425,122	1,624	1,673,099	1,574	4.8	1,759,110
2024	1,105,861	172,469	430,523	1,660	1,710,513	1,574	4.8	1,798,410
2025	1,131,088	177,413	436,185	1,696	1,746,381	1,574	4.8	1,836,088
2026	1,157,933	182,358	442,185	1,731	1,784,208	1,574	4.8	1,875,821
2027	1,183,905	187,306	448,208	1,767	1,821,186	1,574	4.8	1,914,664
2028	1,209,756	192,253	454,142	1,803	1,857,954	1,574	4.8	1,953,286
2029	1,234,164	197,201	459,935	1,839	1,893,138	1,574	4.8	1,990,244
2030	1,261,777	202,147	474,019	1,874	1,939,818	1,574	4.8	2,039,278

** 2009 reflects reclassifications from the Residential Class to Small Commercial General Service Class.*

Table 1-1 cont.
Blue Grass Energy
2010 Load Forecast
Peaks Summary

Winter Season	Noncoincident Peak Demand (MW)	*Summer* Year	Noncoincident Peak Demand (MW)	Year	Purchased Power (MWh)	Load Factor (%)
1989 - 90	172.7	1990	124.4	1990	597,604	39.5%
1990 - 91	155.4	1991	132.9	1991	657,500	48.3%
1991 - 92	175.4	1992	136.6	1992	674,899	43.9%
1992 - 93	177.3	1993	152.3	1993	742,421	47.8%
1993 - 94	218.8	1994	150.0	1994	760,326	39.7%
1994 - 95	190.5	1995	167.7	1995	817,922	49.0%
1995 - 96	223.5	1996	173.8	1996	847,345	43.3%
1996 - 97	225.5	1997	186.7	1997	881,949	44.6%
1997 - 98	204.2	1998	192.3	1998	918,716	51.4%
1998 - 99	233.4	1999	210.6	1999	979,348	47.9%
1999 - 00	248.4	2000	213.0	2000	1,046,882	48.1%
2000 - 01	266.2	2001	217.5	2001	1,060,783	45.5%
2001 - 02	249.3	2002	233.8	2002	1,137,254	52.1%
2002 - 03	296.5	2003	224.5	2003	1,138,813	43.8%
2003 - 04	295.9	2004	223.8	2004	1,174,625	45.3%
2004 - 05	300.3	2005	253.9	2005	1,242,479	47.2%
2005 - 06	285.4	2006	257.4	2006	1,215,593	48.6%
2006 - 07	334.3	2007	272.5	2007	1,310,866	44.8%
2007 - 08	346.2	2008	246.4	2008	1,312,250	43.3%
2008 - 09	362.3	2009	245.3	2009	1,232,819	38.8%
2009 - 10	324.8	2010	268.8	2010	1,269,787	44.6%
2010 - 11	362.2	2011	272.6	2011	1,288,805	40.6%
2011 - 12	370.4	2012	280.0	2012	1,327,110	40.9%
2012 - 13	381.1	2013	289.5	2013	1,365,036	40.9%
2013 - 14	391.0	2014	297.4	2014	1,403,269	41.0%
2014 - 15	400.0	2015	304.6	2015	1,438,641	41.1%
2015- 16	410.4	2016	313.3	2016	1,484,211	41.3%
2016 - 17	420.7	2017	321.6	2017	1,520,127	41.2%
2017 - 18	430.5	2018	329.4	2018	1,558,620	41.3%
2018 - 19	440.7	2019	337.4	2019	1,598,509	41.4%
2019 - 20	449.1	2020	344.1	2020	1,636,497	41.6%
2020 - 21	459.9	2021	352.6	2021	1,673,912	41.5%
2021 - 22	471.4	2022	362.1	2022	1,719,981	41.7%
2022 - 23	481.2	2023	369.8	2023	1,759,110	41.7%
2023 - 24	489.5	2024	376.6	2024	1,798,410	41.9%
2024 - 25	500.2	2025	385.2	2025	1,836,088	41.9%
2025 - 26	509.9	2026	393.1	2026	1,875,821	42.0%
2026 - 27	519.3	2027	400.8	2027	1,914,664	42.1%
2027 - 28	526.9	2028	407.3	2028	1,953,286	42.3%
2028 - 29	537.2	2029	415.9	2029	1,990,244	42.3%
2029 - 30	549.0	2030	425.9	2030	2,039,278	42.4%

Executive Summary *(continued)*
Overall Results

- Total sales are projected to grow by 2.4 percent a year for the period 2010-2030, compared to a 2.3 percent growth projected in the 2008 load forecast for the period 2007-2027. Results shown in Table 1-2 and Figure 1-1.
- Winter and summer peak demands indicate annual growth of 2.2 and 2.3 percent, respectively. Annual peaks shown in Figure 1-2.
- Load factor for the forecast period remains at approximately 41%. See Figure 1-3.

Executive Summary *(continued)*
Overall Results

Table 1-2
Blue Grass Energy-2010 Load Forecast
Summary of Sales Growth Rates

	Time Period	Residential	Small Commercial	Large Commercial	Public Street & Hwy. Lighting	Total Sales
5 Year Growth Rates	1999-2004	3.9%	1.1%	3.8%	6.0%	3.6%
	2004-2009	1.6%	-1.4%	0.7%	5.7%	1.1%
	2010-2015	1.7%	3.3%	4.5%	3.1%	2.5%
	2015-2020	2.6%	3.5%	2.3%	2.5%	2.6%
	2020-2025	2.5%	3.0%	1.7%	2.3%	2.3%
	2025-2030	2.2%	2.6%	1.7%	2.0%	2.1%
10 Year Growth Rates	1999-2009	2.7%	-0.1%	2.3%	5.9%	2.3%
	2010-2020	2.1%	3.4%	3.4%	2.8%	2.6%
	2020-2030	2.3%	2.8%	1.7%	2.1%	2.2%

Figure 1-1
Average Annual Growth in Sales
2010-2030

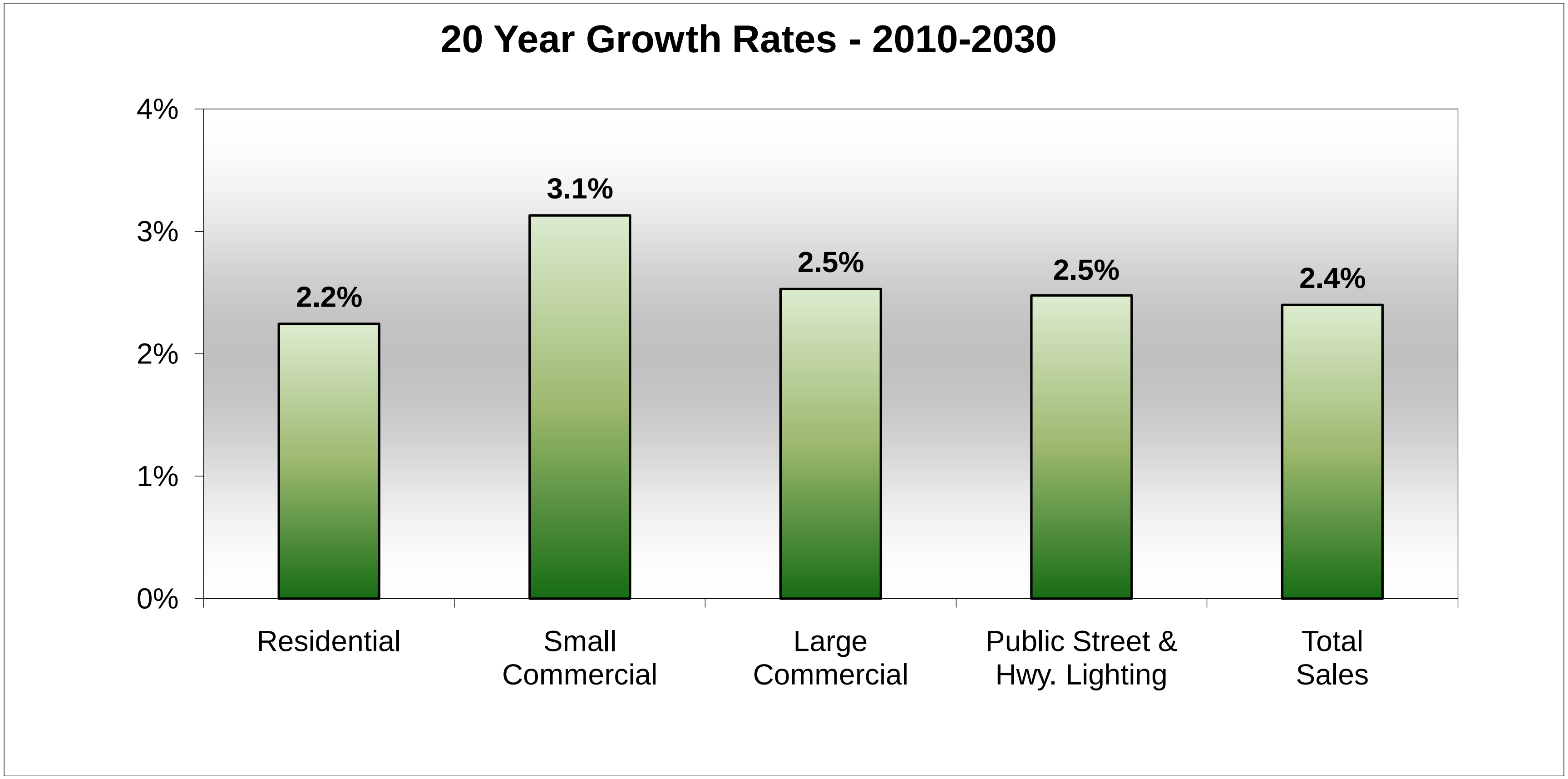


Figure 1-2
Peak Demand Forecast
Winter and Summer

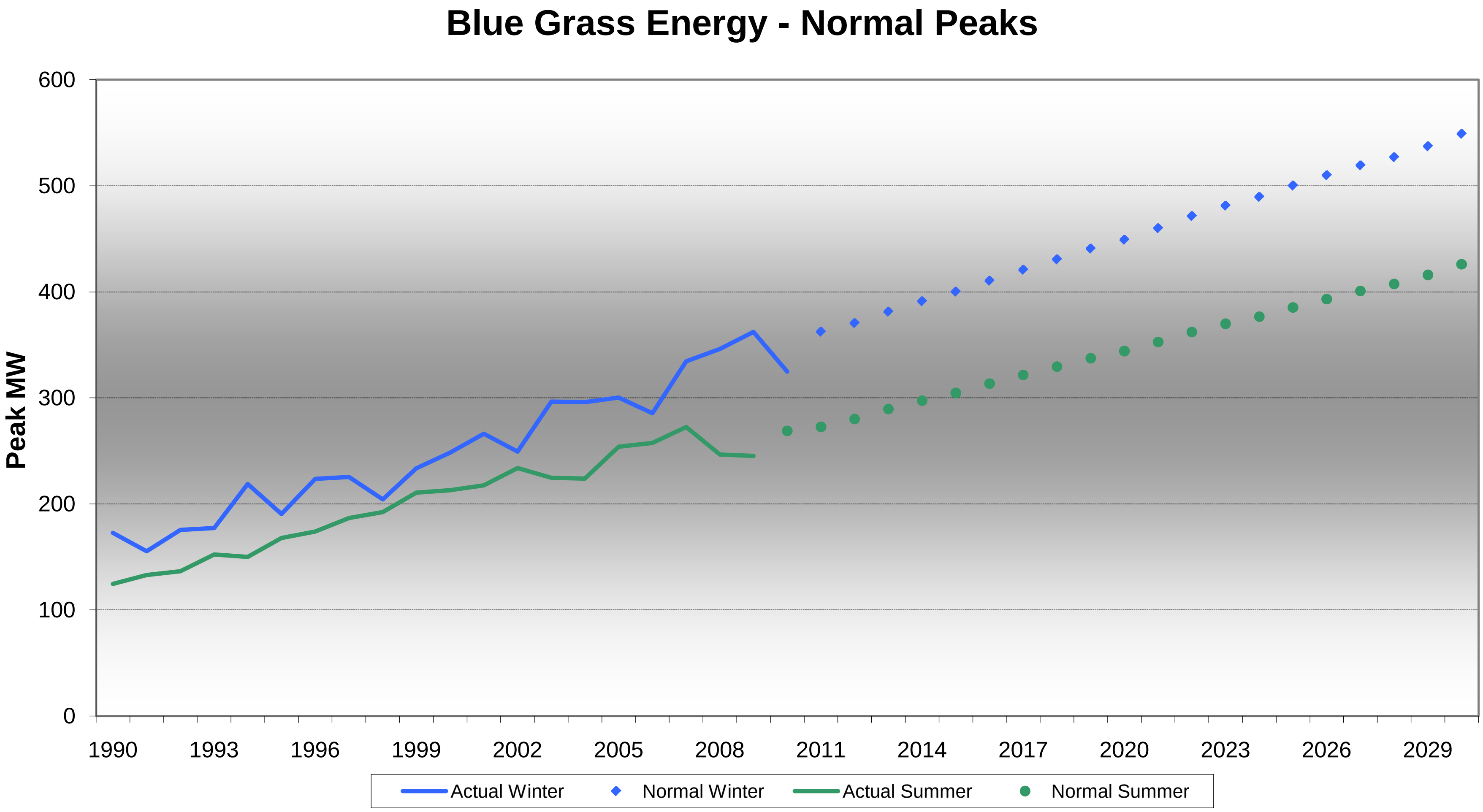
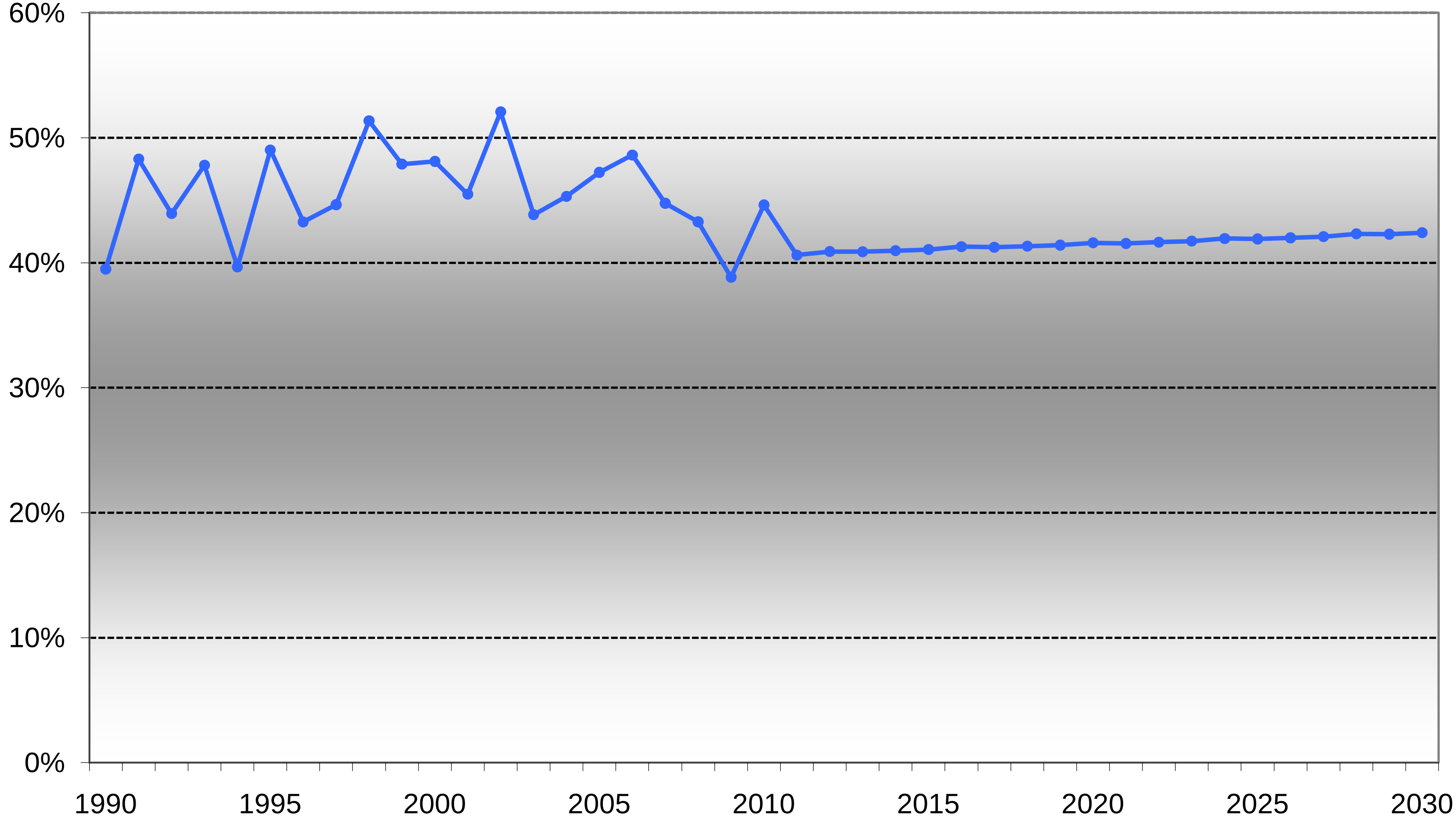


Figure 1-3
Annual System Load Factor



Narrative
Blue Grass Energy Members
Demographic Information

There is an average of 2.51 people per household.

54% of all homes are headed by someone age 55 or greater.

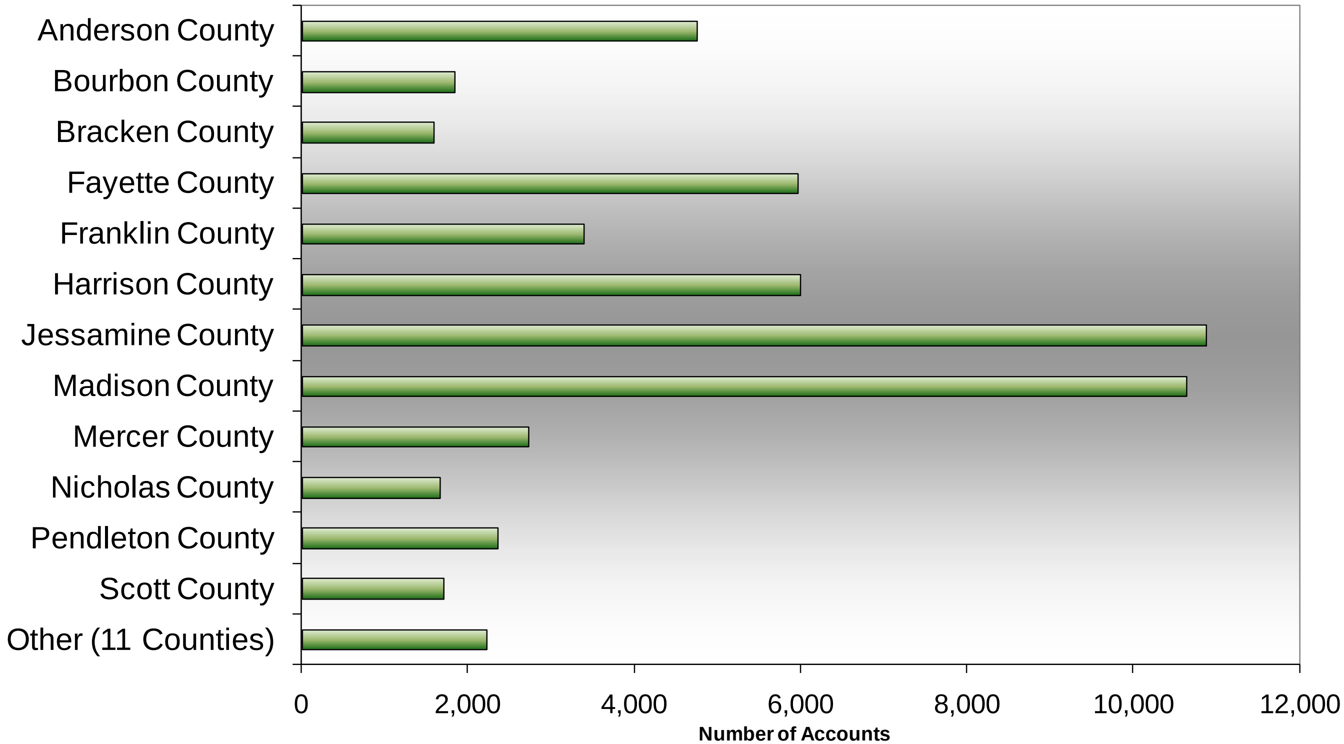
21% of homes have farm operations, with beef cattle most prevalent.

23% of all homes served are less than 10 years old.

Narrative *(continued)*
Counties Served

Blue Grass Energy provides service to members in 23 counties.

Figure 1-4



Key Assumptions
Power Cost and Rates

- EKPC's wholesale power cost forecast used in this load forecast comes from the following report: "Twenty-Year Financial Forecast and Equity Development Plan, 2010-2029", revised May 11, 2010.

- Average residential retail rates will change from 9.787 cents/kWh in 2009 to 17.633 cents/kWh in 2030.

Key Assumptions *(continued)*
Central Economic Region History and Forecast

	Population	(%) Change	Households	(%) Change	Total Employment	(%) Change	Unemployment Rate	(%) Change	Regional Total Income	(%) Change
1990	505,897		192,949		261,835		4.2%		$14,724	
1991	514,596	1.7%	198,344	2.8%	265,692	1.5%	4.2%	-0.4%	$15,302	3.9%
1992	524,323	1.9%	203,138	2.4%	272,004	2.4%	4.2%	-0.6%	$15,841	3.5%
1993	533,045	1.7%	206,781	1.8%	280,184	3.0%	3.6%	-14.7%	$15,990	0.9%
1994	540,583	1.4%	210,503	1.8%	288,478	3.0%	3.3%	-8.0%	$16,381	2.4%
1995	548,600	1.5%	215,120	2.2%	297,872	3.3%	2.9%	-10.4%	$16,795	2.5%
1996	556,676	1.5%	219,487	2.0%	303,710	2.0%	3.2%	8.1%	$17,511	4.3%
1997	564,879	1.5%	223,375	1.8%	314,215	3.5%	2.5%	-22.8%	$18,388	5.0%
1998	573,962	1.6%	227,805	2.0%	324,422	3.2%	2.4%	-2.3%	$19,541	6.3%
1999	582,545	1.5%	232,222	1.9%	332,907	2.6%	2.2%	-7.9%	$20,054	2.6%
2000	589,532	1.2%	235,587	1.4%	336,449	1.1%	3.3%	49.2%	$20,592	2.7%
2001	594,787	0.9%	238,189	1.1%	325,276	-3.3%	4.8%	44.5%	$20,357	-1.1%
2002	600,502	1.0%	240,951	1.2%	324,527	-0.2%	4.7%	-2.2%	$20,509	0.7%
2003	607,482	1.2%	243,863	1.2%	324,705	0.1%	4.8%	2.5%	$20,793	1.4%
2004	615,013	1.2%	246,751	1.2%	327,051	0.7%	4.3%	-9.2%	$21,247	2.2%
2005	623,970	1.5%	248,731	0.8%	334,189	2.2%	5.0%	15.6%	$21,444	0.9%
2006	632,948	1.4%	249,811	0.4%	340,502	1.9%	4.5%	-10.0%	$22,632	5.5%
2007	641,582	1.4%	251,177	0.5%	341,708	0.4%	4.4%	-1.9%	$22,741	0.5%
2008	650,968	1.5%	253,938	1.1%	334,644	-2.1%	5.9%	33.2%	$22,908	0.7%
2009	659,515	1.3%	256,620	1.1%	322,289	-3.7%	9.3%	57.3%	$22,004	-3.9%
2010	667,080	1.1%	261,800	2.0%	323,991	0.5%	9.1%	-1.4%	$22,301	1.3%
2011	674,783	1.2%	266,066	1.6%	331,026	2.2%	8.2%	-10.5%	$22,794	2.2%
2012	682,137	1.1%	269,105	1.1%	339,817	2.7%	7.4%	-9.4%	$23,693	3.9%
2013	689,564	1.1%	273,231	1.5%	346,958	2.1%	7.0%	-4.8%	$24,608	3.9%
2014	696,665	1.0%	276,157	1.1%	352,148	1.5%	6.8%	-3.7%	$25,590	4.0%
2019	731,952	0.8%	296,942	1.0%	372,700	0.8%	5.1%	-4.1%	$30,000	2.3%
2029	801,711	0.9%	331,511	1.1%	404,973	0.8%	4.8%	-0.6%	$39,917	2.9%

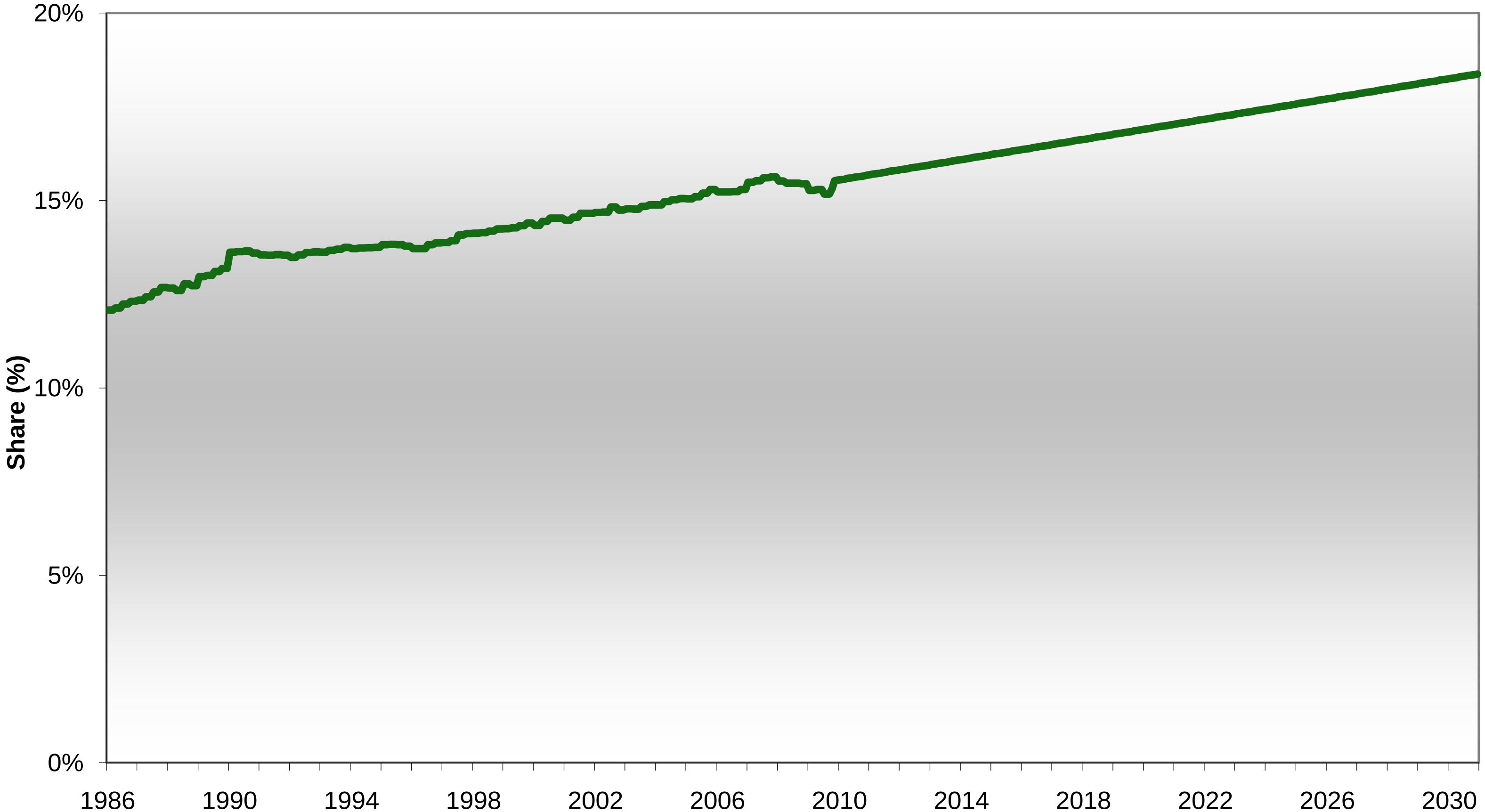
EKPC's source for economic forecasts is Global Insight. Regional Income is reported in millions of 2009 dollars. Growth rates are average annual changes.

Key Assumptions *(continued)*

Share of Regional Homes Served

Blue Grass Energy's market share will increase for the forecast period.

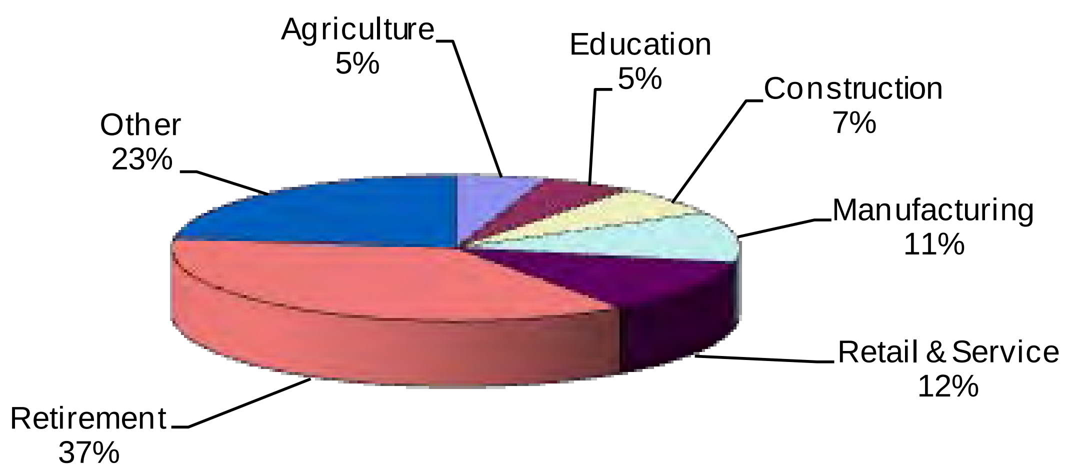
Figure 1-5



Key Assumptions *(continued)*

Household Income
Members' Greatest Sources

Figure 1-6



Key Assumptions *(continued)*
Appliance Saturations

- Electric heat saturation will increase from 64 percent to approximately 68 percent.
- Central air conditioning will continue its penetration into the service area with approximately 88 percent of all residences having central air by 2030.
- Room air conditioner saturation is declining due to customers choosing central air conditioning systems.
- Electric water heater saturation will increase slightly to approximately 89 percent.
- Appliance efficiency trends are accounted for in the model. The data is collected from Energy Information Administration (EIA). See Figure 1-7.
- 77 percent of homes report having at least 1 Compact Fluorescent Light.

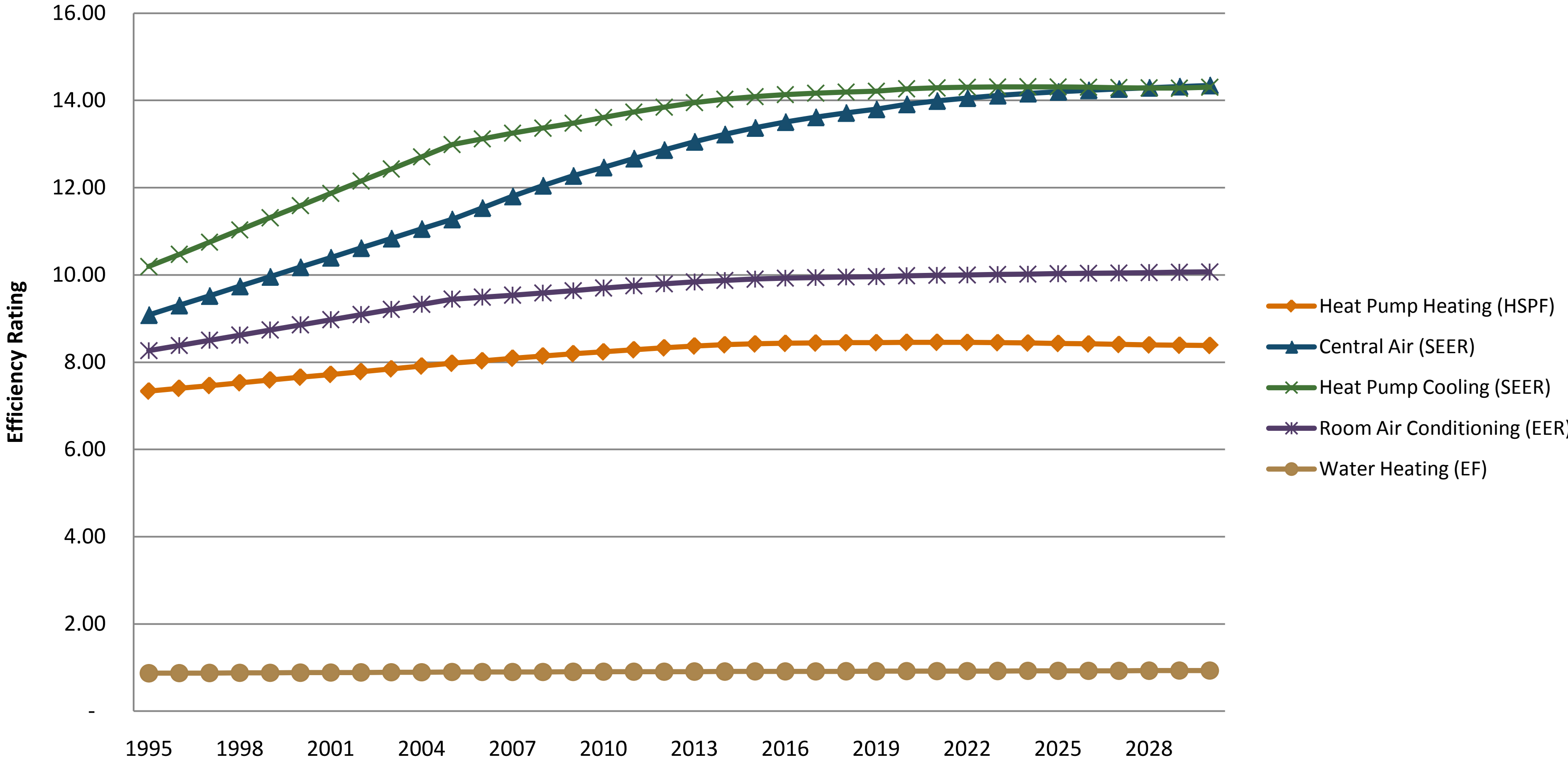
Key Assumptions *(continued)*
Saturation Rates
Non HVAC Appliances

Electric Range	96%
Dishwasher	67%
Freezer	55%
Clothes Dryer	98%
Personal Computer	72%

Key Assumptions *(continued)*

Figure 1-7

Residential Appliance Efficiency Trends
East South Central Region



Source: Energy Information Administration (EIA) Efficiency Trend Update, 2009

Key Assumptions *(continued)*
Weather

- Weather data is from the Blue Grass Airport weather station.
- Normal weather, a 30-year average of historical hourly temperatures, is assumed for the forecast years.

Methodology and Results Introduction

This section briefly describes the methodology used to develop the load forecast and presents results in tabular and graphical form for residential and commercial classifications. Table 1-3 through Table 1-5 shows historical data for Blue Grass Energy as reported on RUS Form 736 and RUS Form 5.

A preliminary forecast is prepared during the first quarter depending on when Blue Grass Energy experiences its winter peak. The first step is modeling the regional economy. Population, income, and employment are among the areas analyzed. The regional model results are used in combination with the historical billing information, appliance saturation data, appliance efficiency data, and weather data to develop the long range forecast.

Table 1-3

Blue Grass Energy Comparative Annual Operating Data

Year	kWh Purchased And Generated	Change	kWh Sold	Change	kWh Loss	% Loss	Billing Peak Demand	Average Number Of Consumers	Miles Of Line	Consumers Per Mile	Cost Of Purchased Power	Cents / kWh
1995	817,922,009		767,856,616		49,315,432	6.0%	190.1	38,834	5,241	7.4	$28,543,872	3.5
1996	847,344,546	3.6%	808,068,283	5.2%	38,492,862	4.5%	217.4	39,863	5,323	7.5	$28,003,307	3.3
1997	881,948,599	4.1%	832,372,368	3.0%	48,812,679	5.5%	221.0	41,320	5,428	7.6	$28,911,720	3.3
1998	918,715,640	4.2%	869,299,838	4.4%	48,672,122	5.3%	192.3	42,802	5,524	7.7	$30,008,290	3.3
1999	979,347,577	6.6%	931,572,726	7.2%	47,003,272	4.8%	226.2	44,422	5,606	7.9	$33,592,840	3.4
2000	1,046,882,284	6.9%	977,635,092	4.9%	68,366,154	6.5%	247.6	45,873	5,673	8.1	$37,077,959	3.5
2001	1,060,782,821	1.3%	1,026,273,686	5.0%	33,619,072	3.2%	258.0	47,093	5,747	8.2	$40,366,370	3.8
2002	1,137,254,113	7.2%	1,071,167,494	4.4%	65,070,993	5.7%	244.0	48,347	5,794	8.3	$42,473,977	3.7
2003	1,138,812,610	0.1%	1,084,748,761	1.3%	53,068,739	4.7%	287.7	49,421	5,847	8.5	$44,737,984	3.9
2004	1,174,624,818	3.1%	1,111,050,270	2.4%	62,519,738	5.3%	284.8	50,775	5,912	8.6	$50,444,868	4.3
2005	1,242,478,615	5.8%	1,187,056,074	6.8%	54,383,205	4.4%	290.0	52,068	4,440	11.7	$63,167,767	5.1
2006	1,215,593,076	-2.2%	1,176,191,462	-0.9%	38,170,415	3.1%	292.6	53,175	4,487	11.9	$66,355,815	5.5
2007	1,310,866,218	7.8%	1,237,361,259	5.2%	71,943,769	5.5%	311.9	54,021	4,535	11.9	$76,312,698	5.8
2008	1,312,249,611	0.1%	1,247,169,548	0.8%	63,452,198	4.8%	335.1	54,694	4,566	12.0	$82,869,778	6.3
2009	1,232,818,537	-6.1%	1,173,229,591	-5.9%	58,054,516	4.7%	350.9	54,816	4,593	11.9	$78,319,200	6.4
Average						4.9%						4.5

Table 1-4

Blue Grass Energy Comparative Annual Operating Data

	Residential		Residential Seasonal		Commercial / Industrial (1 MW Or Less)		Commercial / Industrial (Over 1 MW)		Public Street / Highway Lighting		Public Authorities	
Year	kWh Sales	% Change	kWh Sales	% Change	kWh Sales	% Change	kWh Sales	% Change	kWh Sales	% Change	kWh Sales	% Change
1995	507,435,200				77,613,416		182,296,017		511,983			
1996	535,148,520	5.5%			84,595,081	9.0%	187,760,762	3.0%	563,920	10.1%		
1997	544,423,185	1.7%			89,185,217	5.4%	198,176,186	5.5%	587,780	4.2%		
1998	564,720,599	3.7%			97,193,729	9.0%	206,770,888	4.3%	614,622	4.6%		
1999	597,111,328	5.7%			107,095,869	10.2%	226,724,525	9.7%	641,004	4.3%		
2000	619,876,222	3.8%			113,386,890	5.9%	243,710,030	7.5%	661,950	3.3%		
2001	660,667,021	6.6%			113,468,789	0.1%	251,384,004	3.1%	753,872	13.9%		
2002	693,441,991	5.0%			112,084,493	-1.2%	264,837,957	5.4%	803,053	6.5%		
2003	706,842,242	1.9%			110,316,486	-1.6%	266,766,744	0.7%	823,289	2.5%		
2004	723,398,583	2.3%			113,275,362	2.7%	273,519,012	2.5%	857,313	4.1%		
2005	787,002,336	8.8%			117,057,136	3.3%	282,109,076	3.1%	887,526	3.5%		
2006	766,303,024	-2.6%			126,275,385	7.9%	282,632,633	0.2%	980,420	10.5%		
2007	816,734,824	6.6%			134,477,416	6.5%	285,115,341	0.9%	1,033,678	5.4%		
2008	826,494,821	1.2%			128,983,096	-4.1%	290,597,149	1.9%	1,094,482	5.9%		
* 2009	782,891,075	-5.3%			105,622,218	-18.1%	283,582,748	-2.4%	1,133,550	3.6%		
Average Annual Change												
2 Year	-16,921,875	-5.9%			-14,427,599	-12.3%	-766,297	-1.6%	49,936	-0.9%		
5 Year	11,898,498	-1.5%			-1,530,629	-4.2%	2,012,747	-1.0%	55,247	-0.1%		
10 Year	18,577,975	-1.1%			-147,365	-2.8%	5,685,822	-1.2%	49,255	-0.1%		

** 2009 reflects reclassifications from the Residential Class to Small Commercial General Service Class.*

Table 1-5

Blue Grass Energy Comparative Annual Operating Data

	Residential		Residential Seasonal		Commercial / Industrial (1 MW Or Less)		Commercial / Industrial (Over 1 MW)		Public Street / Highway Lighting		Public Authorities	
Year	Consumers	kwh / Mo.	Consumers	kwh / Mo.	Consumers	kwh / Mo.	Consumers	kwh / Mo.	Consumers	kwh / Mo.	Consumers	kwh / Mo.
1995	37,477	1,128	0		1,329	4,867	10	1,519,133	18	2,370	0	
1996	38,450	1,160	0		1,382	5,101	10	1,564,673	21	2,238	0	
1997	39,866	1,138	0		1,420	5,234	11	1,501,335	23	2,130	0	
1998	41,306	1,139	0		1,458	5,555	13	1,325,454	25	2,049	0	
1999	42,756	1,164	0		1,625	5,492	14	1,349,551	27	1,978	0	
2000	44,108	1,171	0		1,723	5,484	14	1,450,655	28	1,970	0	
2001	45,202	1,218	0		1,845	5,125	13	1,611,436	33	1,904	0	
2002	46,362	1,246	0		1,933	4,832	15	1,471,322	37	1,809	0	
2003	47,406	1,243	0		1,960	4,690	16	1,389,410	39	1,759	0	
2004	48,688	1,238	0		2,030	4,650	16	1,424,578	41	1,743	0	
2005	49,962	1,313	0		2,048	4,763	16	1,469,318	42	1,761	0	
2006	51,011	1,252	0		2,100	5,011	17	1,385,454	47	1,738	0	
2007	51,794	1,314	0		2,161	5,186	17	1,397,624	49	1,758	0	
2008	52,345	1,316	0		2,276	4,723	20	1,210,821	53	1,721	0	
* 2009	52,180	1,250	0		2,556	3,444	28	843,996	52	1,817	0	
10 Year Avg	942	9			93	-205	1	-50,555	3	-16		
5 Year Avg	698	2			105	-241	2	-116,116	2	15		
2 Year Avg	193	-32			198	-871	6	-276,814	2	29		

Annual Changes In Blue Grass Energy's Residential Class

	1998	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*
Consumers	1,440	1,450	1,352	1,094	1,160	1,044	1,282	1,274	1,049	783	551	-165
kWh/month	1	24	7	47	28	-4	-4	75	-61	62	2	-65

** 2009 reflects reclassifications from the Residential Class to Small Commercial General Service Class.*

Methodology and Results *(continued)*

The preliminary forecast was presented to Blue Grass Energy staff, and reviewed by the Rural Utilities Services (RUS) Field Representative. Changes were made to the forecast as needed based on new information, such as new large loads or subdivisions. In some instances, other assumptions were changed based on insights from Blue Grass Energy staff.

Methodology and Results *(continued)*
Residential Forecast

Residential customers are analyzed by means of regression analysis with resulting coefficients used to prepare customer projections. Regressions for residential customers are typically a function of regional economic and demographic variables. Two variables that are very significant are the numbers of households by county in each member system's economic region and the percent of total households served by the member system. Table 1-6 and Figure 1-8 report Blue Grass Energy's customer forecast.

The residential energy sales were projected using a statistically adjusted end-use (SAE) approach. This method of modeling incorporates end-use forecasts and can be used to allocate the monthly and annual forecasts into end-use components. This method, like end-use modeling, requires detailed information about appliance saturation, appliance use, appliance efficiencies, household characteristics, weather characteristics, and demographic and economic information. The SAE approach segments the average household use into heating, cooling, and water heating end-use components. This model accounts for appliance efficiency improvements. Table 1-6 reports Blue Grass Energy's energy forecast.

Table 1-6

Blue Grass Energy

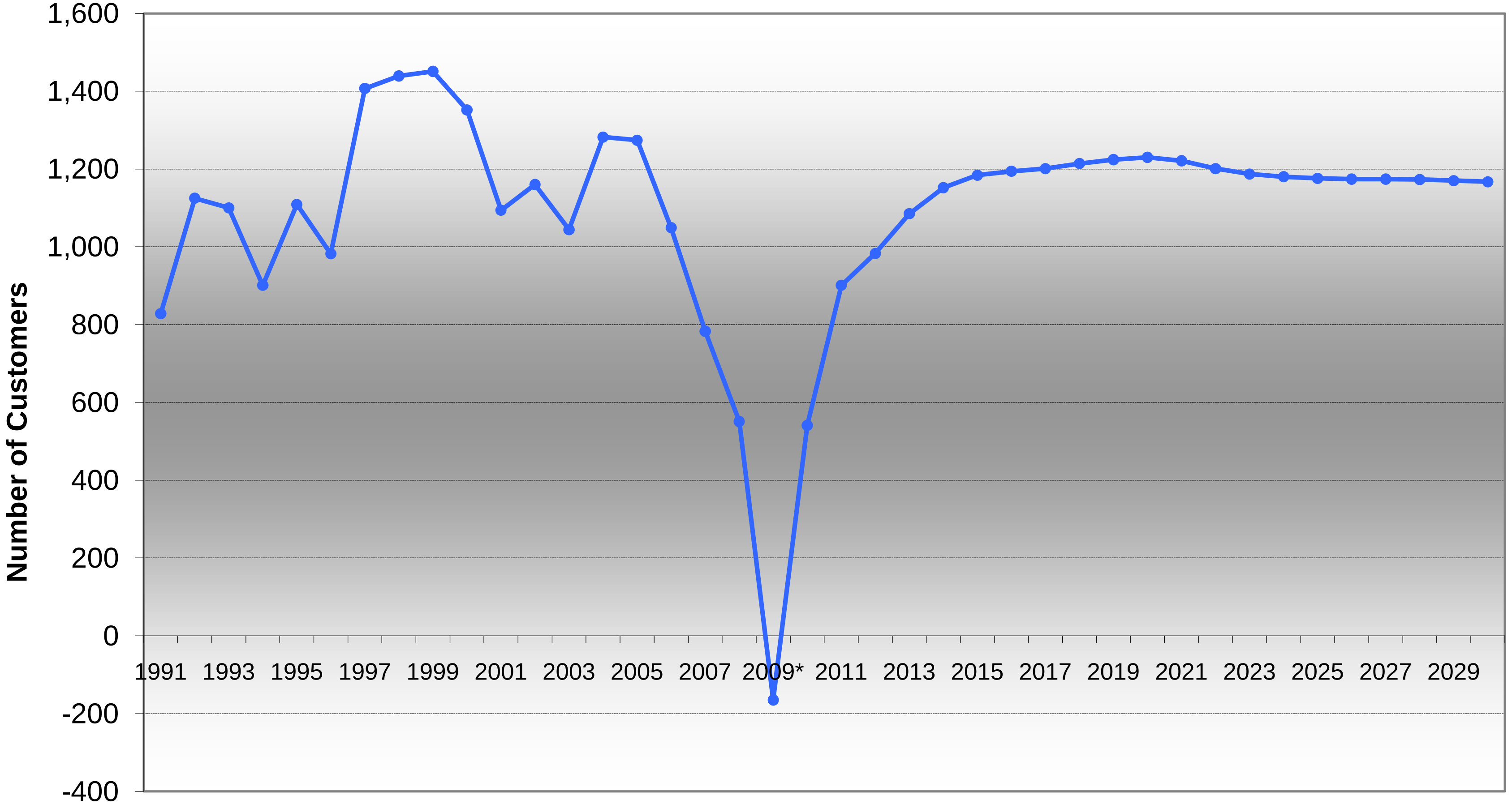
Blue Grass Energy - 2010 Load Forecast

Residential Summary

	Customers			Use Per Customer			Class Sales		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Annual Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	32,414			992			385,788		
1991	33,242	828	2.6	1,060	68	6.8	422,686	36,898	9.6
1992	34,367	1,125	3.4	1,039	-21	-2.0	428,403	5,717	1.4
1993	35,467	1,100	3.2	1,104	65	6.3	469,900	41,497	9.7
1994	36,368	901	2.5	1,103	-1	-0.1	481,416	11,516	2.5
1995	37,477	1,109	3.0	1,128	25	2.3	507,435	26,019	5.4
1996	38,459	982	2.6	1,160	31	2.8	535,149	27,713	5.5
1997	39,866	1,407	3.7	1,138	-22	-1.9	544,423	9,275	1.7
1998	41,305	1,439	3.6	1,139	1	0.1	564,721	20,297	3.7
1999	42,756	1,451	3.5	1,164	24	2.1	597,111	32,391	5.7
2000	44,108	1,352	3.2	1,171	7	0.6	619,876	22,765	3.8
2001	45,202	1,094	2.5	1,218	47	4.0	660,667	40,791	6.6
2002	46,362	1,160	2.6	1,246	28	2.3	693,442	32,775	5.0
2003	47,406	1,044	2.3	1,243	-4	-0.3	706,842	13,400	1.9
2004	48,688	1,282	2.7	1,238	-4	-0.4	723,399	16,556	2.3
2005	49,962	1,274	2.6	1,313	75	6.0	787,002	63,604	8.8
2006	51,011	1,049	2.1	1,252	-61	-4.6	766,303	-20,699	-2.6
2007	51,794	783	1.5	1,314	62	5.0	816,735	50,432	6.6
2008	52,345	551	1.1	1,316	2	0.1	826,495	9,760	1.2
2009*	52,180	-165	-0.3	1,250	-65	-5.0	782,891	-43,604	-5.3
2010	52,721	541	1.0	1,279	29	2.3	809,372	26,481	3.4
2011	53,622	901	1.7	1,271	-8	-0.7	817,746	8,375	1.0
2012	54,605	983	1.8	1,267	-4	-0.3	830,276	12,530	1.5
2013	55,690	1,085	2.0	1,257	-10	-0.8	839,997	9,721	1.2
2014	56,842	1,152	2.1	1,261	4	0.3	860,156	20,159	2.4
2015	58,026	1,184	2.1	1,264	3	0.2	880,261	20,104	2.3
2016	59,220	1,194	2.1	1,271	7	0.6	903,360	23,099	2.6
2017	60,421	1,201	2.0	1,277	6	0.4	925,781	22,421	2.5
2018	61,635	1,214	2.0	1,285	8	0.6	950,160	24,379	2.6
2019	62,859	1,224	2.0	1,294	9	0.7	975,986	25,826	2.7
2020	64,089	1,230	2.0	1,301	7	0.5	1,000,390	24,404	2.5
2021	65,310	1,221	1.9	1,309	8	0.6	1,025,561	25,172	2.5
2022	66,511	1,201	1.8	1,318	9	0.7	1,051,550	25,989	2.5
2023	67,698	1,187	1.8	1,328	10	0.8	1,078,825	27,275	2.6
2024	68,878	1,180	1.7	1,338	10	0.7	1,105,861	27,036	2.5
2025	70,054	1,176	1.7	1,345	8	0.6	1,131,088	25,227	2.3
2026	71,228	1,174	1.7	1,355	9	0.7	1,157,933	26,845	2.4
2027	72,402	1,174	1.6	1,363	8	0.6	1,183,905	25,972	2.2
2028	73,575	1,173	1.6	1,370	8	0.6	1,209,756	25,851	2.2
2029	74,745	1,170	1.6	1,376	6	0.4	1,234,164	24,408	2.0
2030	75,912	1,167	1.6	1,385	9	0.7	1,261,777	27,613	2.2

** 2009 reflects reclassifications from the Residential Class to Small Commercial General Service Class.*

Figure 1-8
Annual Change in Residential Customers



** 2009 reflects reclassifications from the Residential Class to Small Commercial General Service Class.*

Methodology and Results *(continued)*
Small Commercial Forecast

Small commercial sales are projected using two equations, a customer equation and a small commercial sales equation. Both are determined through regression analysis and utilize inputs relating to the economy, electric price, and the residential customer forecast. Small commercial projections are reported in Table 1-7.

Table 1-7

Blue Grass Energy
Blue Grass Energy - 2010 Load Forecast
Small Commercial Summary

	Customers			*Use Per Customer*			*Class Sales*		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Annual Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	1,148			63			72,200		
1991	1,213	65	5.7	54	-9	-13.8	65,729	-6,471	-9.0
1992	1,254	41	3.4	57	3	5.8	71,877	6,148	9.4
1993	1,271	17	1.4	60	2	4.1	75,852	3,975	5.5
1994	1,298	27	2.1	62	2	4.0	80,524	4,672	6.2
1995	1,329	31	2.4	58	-4	-5.9	77,613	-2,911	-3.6
1996	1,382	53	4.0	61	3	4.8	84,595	6,982	9.0
1997	1,420	38	2.7	63	2	2.6	89,185	4,590	5.4
1998	1,459	39	2.7	67	4	6.1	97,194	8,009	9.0
1999	1,625	166	11.4	66	-1	-1.1	107,096	9,902	10.2
2000	1,723	98	6.0	66	0	-0.1	113,387	6,291	5.9
2001	1,845	122	7.1	62	-4	-6.5	113,469	82	0.1
2002	1,933	88	4.8	58	-4	-5.7	112,084	-1,384	-1.2
2003	1,960	27	1.4	56	-2	-2.9	110,316	-1,768	-1.6
2004	2,030	70	3.6	56	0	-0.9	113,275	2,959	2.7
2005	2,048	18	0.9	57	1	2.4	117,057	3,782	3.3
2006	2,100	52	2.5	60	3	5.2	126,275	9,218	7.9
2007	2,161	61	2.9	62	2	3.5	134,477	8,202	6.5
2008	2,276	115	5.3	57	-6	-8.9	128,983	-5,494	-4.1
2009*	2,556	280	12.3	41	-15	-27.1	105,622	-23,361	-18.1
2010	2,595	39	1.5	42	1	1.8	109,114	3,492	3.3
2011	2,636	41	1.6	43	0	1.2	112,154	3,040	2.8
2012	2,688	52	2.0	43	1	1.2	115,736	3,582	3.2
2013	2,748	60	2.2	44	1	1.2	119,753	4,017	3.5
2014	2,813	65	2.4	44	1	1.2	124,083	4,330	3.6
2015	2,882	69	2.5	45	1	1.2	128,624	4,541	3.7
2016	2,952	70	2.4	45	1	1.2	133,306	4,682	3.6
2017	3,025	73	2.5	46	0	1.1	138,082	4,776	3.6
2018	3,098	73	2.4	46	0	1.1	142,923	4,841	3.5
2019	3,172	74	2.4	47	0	1.0	147,809	4,886	3.4
2020	3,246	74	2.3	47	0	1.0	152,724	4,915	3.3
2021	3,321	75	2.3	47	0	0.9	157,653	4,930	3.2
2022	3,395	74	2.2	48	0	0.9	162,589	4,935	3.1
2023	3,470	75	2.2	48	0	0.8	167,527	4,939	3.0
2024	3,545	75	2.2	49	0	0.8	172,469	4,942	2.9
2025	3,620	75	2.1	49	0	0.7	177,413	4,944	2.9
2026	3,695	75	2.1	49	0	0.7	182,358	4,946	2.8
2027	3,769	74	2.0	50	0	0.7	187,306	4,947	2.7
2028	3,844	75	2.0	50	0	0.6	192,253	4,948	2.6
2029	3,919	75	2.0	50	0	0.6	197,201	4,947	2.6
2030	3,994	75	1.9	51	0	0.6	202,147	4,947	2.5

** 2009 reflects reclassifications from the Residential Class to Small Commercial General Service Class.*

Methodology and Results *(continued)*

Large Commercial Forecast

Large commercial customers are those with loads 1 MW or greater. Blue Grass Energy currently has 28 customers in this class and is projected to increase to 32 customers by 2030. Large commercial results are reported in Table 1-8.

Table 1-8

Blue Grass Energy

Blue Grass Energy - 2010 Load Forecast

Large Commercial Summary

	Customers			Use Per Customer			Class Sales		
	Annual Average	Annual Change	% Change	Annual Average (MWh)	Annual Change (MWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	7			15,189			106,324		
1991	9	2	28.6	14,370	-819	-5.4	129,330	23,006	21.6
1992	9	0	0.0	15,323	953	6.6	137,909	8,579	6.6
1993	11	2	22.2	13,721	-1,602	-10.5	150,928	13,020	9.4
1994	11	0	0.0	14,908	1,187	8.7	163,989	13,060	8.7
1995	10	-1	-9.1	18,230	3,322	22.3	182,296	18,307	11.2
1996	10	0	0.0	18,776	546	3.0	187,761	5,465	3.0
1997	11	1	10.0	18,016	-760	-4.0	198,176	10,415	5.5
1998	13	2	18.2	15,905	-2,111	-11.7	206,771	8,595	4.3
1999	14	1	7.7	16,195	289	1.8	226,725	19,954	9.7
2000	14	0	0.0	17,408	1,213	7.5	243,710	16,986	7.5
2001	13	-1	-7.1	19,337	1,929	11.1	251,384	7,674	3.1
2002	15	2	15.4	17,656	-1,681	-8.7	264,838	13,454	5.4
2003	16	1	6.7	16,673	-983	-5.6	266,767	1,929	0.7
2004	16	0	0.0	17,095	422	2.5	273,519	6,752	2.5
2005	16	0	0.0	17,632	537	3.1	282,109	8,590	3.1
2006	17	1	6.3	16,625	-1,006	-5.7	282,633	524	0.2
2007	17	0	0.0	16,771	146	0.9	285,115	2,483	0.9
2008	20	3	17.6	14,530	-2,242	-13.4	290,597	5,482	1.9
2009	28	8	40.0	10,128	-4,402	-30.3	283,583	-7,014	-2.4
2010	27	-1	-3.6	10,653	525	5.2	287,629	4,046	1.4
2011	27	0	0.0	10,899	246	2.3	294,273	6,644	2.3
2012	28	1	3.7	11,235	336	3.1	314,592	20,319	6.9
2013	29	1	3.6	11,618	383	3.4	336,923	22,331	7.1
2014	29	0	0.0	12,027	409	3.5	348,797	11,873	3.5
2015	29	0	0.0	12,338	310	2.6	357,789	8,992	2.6
2016	30	1	3.4	12,445	108	0.9	373,355	15,566	4.4
2017	30	0	0.0	12,677	232	1.9	380,315	6,960	1.9
2018	30	0	0.0	12,923	246	1.9	387,703	7,388	1.9
2019	30	0	0.0	13,164	241	1.9	394,930	7,227	1.9
2020	30	0	0.0	13,391	227	1.7	401,741	6,811	1.7
2021	30	0	0.0	13,574	183	1.4	407,223	5,482	1.4
2022	31	1	3.3	13,552	-22	-0.2	420,121	12,898	3.2
2023	31	0	0.0	13,714	161	1.2	425,122	5,001	1.2
2024	31	0	0.0	13,888	174	1.3	430,523	5,401	1.3
2025	31	0	0.0	14,070	183	1.3	436,185	5,662	1.3
2026	31	0	0.0	14,264	194	1.4	442,185	6,000	1.4
2027	31	0	0.0	14,458	194	1.4	448,208	6,023	1.4
2028	31	0	0.0	14,650	191	1.3	454,142	5,934	1.3
2029	31	0	0.0	14,837	187	1.3	459,935	5,793	1.3
2030	32	1	3.2	14,813	-24	-0.2	474,019	14,084	3.1

Methodology and Results *(continued)*

Public Street & Highway Lighting Forecast

Blue Grass Energy serves street light accounts which are classified in the 'Public Street & Highway Lighting Forecast' category. This class is modeled separately. Results are reported in Table 1-9.

Table 1-9

Blue Grass Energy - 2010 Load Forecast

Public Street & Highway Lighting Summary

	Customers			Use Per Customer			Class Sales		
	Annual Average	Annual Change	% Change	Monthly Average (kWh)	Annual Change (kWh)	% Change	Total (MWh)	Annual Change (MWh)	% Change
1990	14			2,351			395		
1991	16	2	14.3	2,091	-260	-11.1	402	7	1.6
1992	16	0	0.0	2,566	475	22.7	493	91	22.7
1993	16	0	0.0	3,060	494	19.3	588	95	19.3
1994	17	1	6.3	2,685	-376	-12.3	548	-40	-6.8
1995	18	1	5.9	2,370	-315	-11.7	512	-36	-6.5
1996	21	3	16.7	2,238	-133	-5.6	564	52	10.1
1997	23	2	9.5	2,130	-108	-4.8	588	24	4.2
1998	25	2	8.7	2,049	-81	-3.8	615	27	4.6
1999	27	2	8.0	1,978	-70	-3.4	641	26	4.3
2000	28	1	3.7	1,970	-8	-0.4	662	21	3.3
2001	33	5	17.9	1,904	-66	-3.4	754	92	13.9
2002	37	4	12.1	1,809	-95	-5.0	803	49	6.5
2003	39	2	5.4	1,759	-50	-2.7	823	20	2.5
2004	41	2	5.1	1,743	-17	-0.9	857	34	4.1
2005	42	1	2.4	1,761	18	1.1	888	30	3.5
2006	47	5	11.9	1,738	-23	-1.3	980	93	10.5
2007	49	2	4.3	1,758	20	1.1	1,034	53	5.4
2008	53	4	8.2	1,721	-37	-2.1	1,094	61	5.9
2009	52	-1	-1.9	1,817	96	5.6	1,134	39	3.6
2010	54	2	3.8	1,773	-44	-2.4	1,149	15	1.4
2011	55	1	1.9	1,810	37	2.1	1,194	46	4.0
2012	57	2	3.6	1,799	-11	-0.6	1,230	36	3.0
2013	59	2	3.5	1,788	-10	-0.6	1,266	36	2.9
2014	61	2	3.4	1,778	-10	-0.5	1,302	36	2.8
2015	62	1	1.6	1,798	19	1.1	1,338	36	2.7
2016	64	2	3.2	1,788	-10	-0.5	1,373	36	2.7
2017	66	2	3.1	1,779	-9	-0.5	1,409	36	2.6
2018	68	2	3.0	1,771	-8	-0.5	1,445	36	2.5
2019	69	1	1.5	1,788	18	1.0	1,481	36	2.5
2020	71	2	2.9	1,780	-8	-0.5	1,517	36	2.4
2021	73	2	2.8	1,772	-8	-0.4	1,552	36	2.4
2022	75	2	2.7	1,765	-7	-0.4	1,588	36	2.3
2023	76	1	1.3	1,781	16	0.9	1,624	36	2.3
2024	78	2	2.6	1,773	-7	-0.4	1,660	36	2.2
2025	80	2	2.6	1,766	-7	-0.4	1,696	36	2.2
2026	82	2	2.5	1,759	-7	-0.4	1,731	36	2.1
2027	83	1	1.2	1,774	15	0.8	1,767	36	2.1
2028	85	2	2.4	1,768	-7	-0.4	1,803	36	2.0
2029	87	2	2.4	1,761	-6	-0.4	1,839	36	2.0
2030	89	2	2.3	1,755	-6	-0.3	1,874	36	1.9

Methodology and Results *(continued)*

Peak Day Weather Scenarios

Extreme temperatures can dramatically influence Blue Grass Energy's peak demands. Table 1-10 and Figure 1-9 reports the impact of extreme weather on system demands.

Blue Grass Energy
Peak Day Weather Scenarios

Winter Peak Day Minimum Temperatures

	Mild	Normal	**Extreme**		
Degrees	10	-3	-12	-17	-25
Probability	*99%*	*50%*	*20%*	*10%*	*3%*
Occurs Once Every		**2 Years**	**5 Years**	**10 Years**	**30 Years**

Noncoincident Winter Peak Demand - MW

Season	Mild	Normal	Extreme		
2010 - 11	338	362	379	389	404
2011 - 12	345	370	388	397	413
2012 - 13	356	381	399	408	424
2013 - 14	365	391	409	419	435
2014 - 15	374	400	418	429	445
2015- 16	383	410	429	439	456
2016 - 17	393	421	440	450	467
2017 - 18	402	431	450	461	478
2018 - 19	412	441	461	472	489
2019 - 20	420	449	469	481	499
2020 - 21	430	460	481	492	510
2021 - 22	441	471	492	504	523
2022 - 23	450	481	503	514	534
2023 - 24	458	489	511	523	543
2024 - 25	468	500	522	535	554
2025 - 26	477	510	532	545	565
2026 - 27	486	519	542	555	575
2027 - 28	493	527	550	563	584
2028 - 29	503	537	561	574	595
2029 - 30	514	549	573	586	608

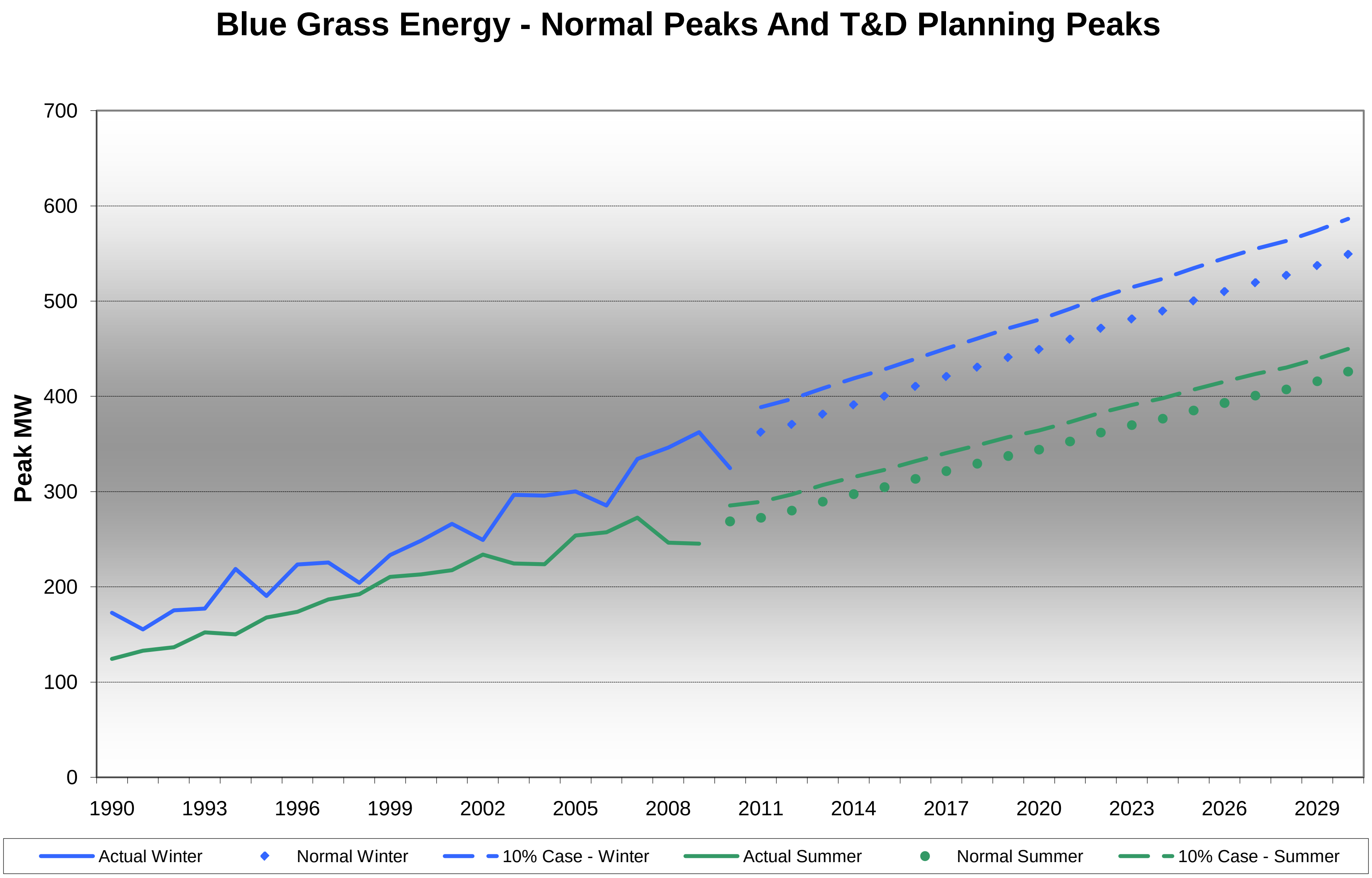
Summer Peak Day Maximum Temperatures

	Normal	**Extreme**		
Degrees	96	98	100	104
Probability	*50%*	*20%*	*10%*	*3%*
	2 Years	**5 Years**	**10 Years**	**30 Years**

Noncoincident Summer Peak Demand - MW

Year	Normal	Extreme		
2010	269	277	285	302
2011	273	281	289	306
2012	280	288	297	314
2013	289	298	307	324
2014	297	306	315	333
2015	305	314	323	341
2016	313	322	332	350
2017	322	331	340	359
2018	329	339	349	368
2019	337	347	357	377
2020	344	354	364	384
2021	353	363	373	393
2022	362	372	383	404
2023	370	380	391	412
2024	377	387	398	420
2025	385	396	407	429
2026	393	404	415	438
2027	401	412	424	446
2028	407	419	430	453
2029	416	427	439	463
2030	426	438	450	473

Figure 1-9



Blue Grass Energy - Normal Peaks And T&D Planning Peaks
Peak MW
700
600
500
400
300
200
100
0
1990
1993
1996
1999
2002
2005
2008
2011
2014
2017
2020
2023
2026
2029
Actual Winter
Normal Winter
10% Case - Winter
Actual Summer
Normal Summer
10% Case - Summer

LOAD FORECAST SUMMARY	
1. Borrower Designation	KY 64
2. Name of Borrower	Blue Grass Energy
3. Date	June 25, 2010

CLASS OF CONSUMER	NO. OF CONSUMERS			AVG. MONTHLY KWH USAGE		
	2009	2014	2019	2009	2014	2019
4. Residential	52,180	56,842	62,859	1,250	1,261	1,294
5. Seasonal						
6. Irrigation						
7. Commercial & Industrial 1000 kVa or less	2,556	2,813	3,172	3,444	3,676	3,883
8. Commercial & Industrial over 1000 kVa	28	29	30	843,996	1,002,289	1,097,029
9. Public Street & Highway Lighting	52	61	69	1,817	1,778	1,788
10. Other Sales to Public Authorities						
11. Sales for Resale - REA Borrowers						
12. Sales for Resale - Others						

TOTAL SYSTEM POWER REQUIREMENTS

ITEM	2009	2014	2019
13. Annual MWh Requirements	1,232,819	1,403,269	1,598,509
14. Including Losses @	4.7%	4.8%	4.8%
15. Annual Load Factor (Based on maximum monthly system peak demand)	38.8%	41.0%	41.4%
16. Maximum Monthly System Peak Demand (MW) Noncoincident	362.3	391.0	440.7
17. Source(s) of Supply	East Kentucky Power Cooperative, Inc.		
18. Previous Power Requirements Study Dated:	Jul-08		
19. Comments (Use an additional sheet if more space is needed)			

Borrower's General Manager (Signature)	Date	RUS General Field Representative (Signature)	Date
D W Brewer	8/16/2010	Mike Norman	6/25/2010

RUS Form 341

RESOLUTION

WHEREAS, the 2010 Load Forecast Study has been prepared by East Kentucky Power using an end-use model, with full participation of Blue Grass Energy Cooperative Corporation management and staff, and approved by the RUS Field Representative, Mike J. Norman.

NOW, THEREFORE BE IT RESOLVED, that the Board of Directors approve the Load Forecast Study for use in the Two Year Work Plan, Financial Forecast, and other studies, and as part of the East Kentucky Power Cooperative Load Forecast Study.

I, Jody Hughes, do hereby certify that the above is a true and correct excerpt from the Minutes of the Board of Directors of Blue Grass Energy Cooperative Corporation, held on 15th day of July 2010, at which meeting a quorum was present.

Chairman

Blue Grass Energy
Cooperative Corporation

Long Range Plan

May 2004

Kentucky 64 - Jessamine

Nicholasville, Kentucky

STATE OF KENTUCKY
JAMES D. BRIDGES
16457
LICENSED
PROFESSIONAL ENGINEER

I hereby certify that this 2004 Long Range System Planning Report was prepared by me or under my direct supervision and that I am a duly registered professional engineer under the laws of the State of Kentucky. Registration No. 16457

April 23, 2004
Date

By: James D. Bridges, P.E.
James D. Bridges, P.E.

Distribution System Solutions, Inc.
Walton, Kentucky

Blue Grass Energy
Cooperative Corporation

Long Range Plan
May 2004

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APPENDICES

I. INTRODUCTION

I.1 Purpose

The Long Range Plan (LRP) is a management tool and guide for the practical and economic means of serving future loads and maintaining a high quality of service to all customers. The plan outlines anticipated system changes in terms of major facilities, demand levels and associated costs. Such an outline will aid the cooperative in financial planning and decision making. This system planning report encompasses the Blue Grass Energy Cooperative Corporation's (BGE) *2004 Ten-Year Long Range Plan.* The plan investigates and examines the BGE electrical distribution system through the 2014 projected system peak load level.

I.2 Long Range Planning Study Procedure

An engineering analysis has been performed for the existing substation areas. Major industrial loads, with dedicated substations, were not specifically analyzed. The plan is broken into three future load levels. There are two transitional load levels: Load Level A-2006 and Load Level B-2010. The Long Range Plan load level is Load Level C-2014. This projected load level is approximately 1.7 times the existing system kW demand. The magnitude and location of future system loading is projected. The years during which these future load levels are actually reached are likely to differ from the years listed in the plan. The expansion of the system is controlled more by load growth and load location than by time.

The system has been "grown" to the three future kW load levels based upon the *2002 Load Forecast* (LF). The LF is a joint planning effort between BGE and East Kentucky Power Cooperative, Inc.(EKPC), the wholesale power supplier. The Rural Utilities Service's general field representative, the BGE staff and the planning engineers reviewed the projected loading forecasts and agreed upon the load levels to be used in the LRP study.

Exploratory plans were examined for each load level. Two overall plans were developed. The total cost for each plan was tabulated and present worth economics was used in order to aid in the evaluation of the two plans.

Some system improvements in these two plans may overlap or occur at different load levels. It is important to have a viable alternate plan since transmission easements, substation site procurement and other unforeseen factors may affect the implementation of the preferred plan.

I.3 Service Area

Blue Grass Energy's headquarters are located in Nicholasville, Kentucky. Blue Grass Energy consists of four main districts: Nicholasville, Madison, Fox Creek, and Harrison. Electric service is supplied to major portions of the rural areas of the following counties grouped by each district.

The Nicholasville and Madison Districts serve much of the rural area to the south of Lexington, Kentucky and include portions of Fayette, Jessamine, and Madison Counties. The Kentucky River bisects the service territory. Much of BGE's growth in this area can be contributed to its close proximity to Lexington, which is easily accessible by US Highways 68 and 27, and Interstate I-75.

The Fox Creek District is located to the west of Lexington and south of the state capitol of Frankfort. In this district BGE serves most of the rural areas of Anderson County, and portions of Woodford, Mercer, and Franklin Counties. Much of the growth in this area is attributed to its close proximity to the towns of Lawrenceburg, Versailles, and Frankfort; and the Blue Grass Parkway lends easy access to Lexington. Interstate I-64 runs along the northern portion of the Fox Creek District and the Blue Grass Parkway traverses the southern portion of the district.

The Harrison District is located to the northwest of Lexington. In this district, BGE serves most of the rural areas of Harrison County and portions of Scott, Bourbon, Nicholas, Bracken, Pendleton, Robertson and Grant Counties. Much of the present growth in this district centers east of the city of Georgetown, which has a new residential subdivision and industrial park that will be served by BGE. The local economy is somewhat dependent upon the automotive manufacturing industry present in Georgetown. US Highways 27 and 62 intersect in the center of this district.

BGE operates over 5,794 miles of line within the four districts. The primary voltage is 7,200/12,470 volts grounded wye for the Nicholasville, Madison and Harrison Districts. The Fox Creek District power system operates at two primary voltages: 7,200/12,470 volts grounded wye and 14,400/24,940 volts grounded wye. There are a total of 26 distribution substations presently serving the entire BGE rural system. Six additional substation/transformers are dedicated primarily to industrial sites with a few small commercial loads served in some cases. Installed overhead distribution conductor sizes range from #8 ACWC to 556 MCM ACSR. Underground distribution conductor sizes range from 1/0 URD to 500 MCM URD.

I.4 Power Supply

East Kentucky Power Cooperative (EKPC) provides all power and energy needs to BGE. EKPC is located in Winchester, Kentucky.

The 2002 Load Forecast (LF) is a joint effort between BGE and EKPC. BGE provides loading data and system growth predictions to EKPC for use in the LF growth models. All new distribution, transmission, and substation construction requirements are considered simultaneously as a "one system" concept - between BGE & EKPC - for the orderly and economical development of the total system. All of the recommendations relative to power supply and delivery are discussed with EKPC.

Transmission wheeling from the Kentucky Utilities Company (KU) was not specifically considered in the LRP report. Many times, it can not easily be determined whether EKPC will directly serve a proposed substation or whether they must tap and wheel power from KU –the investor-owned utility in the area. In a specific substation justification, wheeling is considered because a actual site locations have been selected.

II. ANALYSIS, CONCLUSIONS AND RECOMMENDATIONS

II.1 Analysis

The Preferred and Alternate Long Range Plans were developed independently. Various exploratory scenarios were analyzed. The preferred plan is a combination of what was regarded as the best of the exploratory scenarios.

Many improvements are identical in both plans. Other improvements are the same, but may appear at different load levels. Voltage regulators are utilized in this Long Range Plan. While no new voltage regulators were added in the Long Range "C" Load Level, existing regulators were permitted to remain in service.

II.2 Conclusions

In present worth dollars, the Preferred plan is $1,687,838 less costly than the Alternate plan. The Preferred plan recommends ten new substations and five transformer additions at existing substations.

The **Oxford, South Point and Powell Taylor Substations,** are all recommended in Load Level "A." The Oxford Substation will relieve extreme loading on the western feeders of the Lees Lick Substation. Residential and industrial growth around the Toyota facility has stressed the existing system. The South Point Substation will serve the new commercial development on US 27 at the Fayette-Jessamine county line. The existing Davis Substation cannot economically serve this development when it is completed. The Powell Taylor Substation will serve the growth area to the west of Lawrenceburg. Strong residential growth in this area was stressing existing feeders from the Bridgeport, Sinai, and Ninevah substations.

The **Duncanon** and **Big Hill Substations** are recommended in Load Level "B." The Duncanon Substation will serve the projected load in the area around the new I-75 interchange. Existing feeders were unable to serve the projected loads. The Big Hill Substation will serve the southeast area of the Madison District. Feeders from Hickory Plains will be unable to serve the projected loading in this area.

The **Ebenezer, West Cynthiana, Ruddles Mills, North Nicholasville and Boone Gap (Jackson Energy) Substations** are recommended in Load Level "C"...which is the Long Range Load Level. The Ebenezer Substation will serve the southernmost area of the Fox Creek District. This area is presently served from the

Vanarsdell Substation. Continuing growth along the US 127 corridor will stress the existing facilities. The West Cynthiana Substation will relieve transformer load and feeder stress on the existing Cynthiana Substation. Carefully planned industrial and residential growth is projected around the load center of this new substation. The Ruddles Mills Substation will relieve feeder loading out of both the Millersburg and Cynthiana Substations. The load center for this substation lies between US 27 and US 68 to the west of Millersburg in Bourbon County. Continuing clustered developments in this area are projected. The North Nicholasville Substation will relieve a portion the projected loading in this high-growth area of the US 27 corridor. The Boone Gap Substation will be constructed, in the next couple of years, in the Jackson Energy Cooperative's service area. It is recommended that BGE take a feeder northward out of this substation into its service area south of Berea. There is a significant load projected on the end of the existing West Berea line. This new feed will greatly improve voltage levels and reduce losses.

No changes in conductor sizes are recommended. An economic conductor analysis is included in the Appendices. The predominant three-phase, aluminum conductor on the system is 1/0 ACSR. 336.4 ACSR was recommended in high growth areas or near present or proposed substations.

The aged conductor replacement schedules were nearly identical in the two plans. Most of this type of replacement is based on system reliability improvement due to reducing conductor failures. Voltage drop and thermal loading are generally not issues in aged conductor replacement. An aged conductor summary is located in the Appendices of this report.

Conversion of additional portions of the Fox Creek District's system to 25 kV was recommended in both the Preferred and the Alternate plans. It is strongly recommended – and both plans reflect – that existing aged copper not be converted to a higher voltage. Experience has shown that aged copper and even aged (30 years +) ACSR conductor should normally not be converted to a higher voltage. This theme, combined with least cost planning methods, generally did not permit vast areas of the Fox Creek District to be wholly converted to 25 kV. Cost, overcurrent coordination and operational factors normally dictate a more methodical approach. There were no 25 kV conversions recommended in the Preferred Plan for any of the other districts.

II.3 Recommendations

This Preferred Long Range Plan will provide a guideline upon which future BGE Construction Work Plans may be based. The recommendations in this plan will adequately serve the projected 65,700 customers at the Long Range load level of 501,000 kW.

The Preferred plan is the less expensive plan. The Alternate plan also recommends ten new substations but does not provide any reduction in the cost of losses over a ten-year, present worth analysis. At some time in the future, portions of the Alternate plan may ultimately be more viable than a given project in the Preferred plan. However, it is recommended that the Preferred plan be utilized as the Long Range System Plan.

Economic Comparison of Annual Costs of Plans

PREFERRED	SYSTEM IMPROVEMENTS	LINE EXTENSION & MAINTENANCE	SUBSTATIONS & UPGRADES	TRANSMISSION EXTENSIONS	LINE LOSSES	TOTAL $/LOAD BLOCK
2006	$2,244,034	$4,949,713	$550,150	$238,102	$1,619,870	$9,601,869
2010	$8,311,756	$22,685,250	$1,925,421	$828,519	$2,880,199	$36,631,145
2014	$15,974,616	$42,687,088	$3,521,339	$1,771,445	$3,534,531	$67,489,019
TOTAL ITEM COST	$26,530,406	$70,322,051	$5,996,910	$2,838,066	$8,034,600	$113,722,033
PRESENT WORTH	$18,612,155	$49,114,169	$4,043,051	$1,889,540	$6,028,841	$79,687,756

ALTERNATE	SYSTEM IMPROVEMENTS	LINE EXTENSION & MAINTENANCE	SUBSTATIONS & UPGRADES	TRANSMISSION EXTENSIONS	LINE LOSSES	TOTAL $/LOAD BLOCK
2006	$2,878,652	$4,949,713	$465,478	$36,662	$1,621,591	$9,952,096
2010	$9,652,172	$22,685,250	$1,891,872	$1,051,564	$2,879,712	$38,160,570
2014	$15,521,775	$42,687,088	$3,740,906	$2,259,207	$3,555,043	$67,764,019
TOTAL ITEM COST	$28,052,599	$70,322,051	$6,098,256	$3,347,433	$8,056,346	$115,876,685
PRESENT WORTH	$20,001,404	$49,114,169	$4,064,302	$2,152,968	$6,042,751	$81,375,594

BLUE GRASS ENERGY COOPERATIVE CORPORATION

TABLE II-1
COST SUMMARY DATA FOR LONG RANGE PLAN KY-64 JESSAMINE
Projections in 2004 dollars

DESCRIPTION	ACTUAL 02-03*	Load Level A	Load Level B	Load Level C	LRP TOTAL
New Customers (100)					
1. New services constructed	2,807	3,200	6,400	6,400	16,000
2. Cost per Customer	$4,465	$3,000	$3,000	$3,000	
3. Cost of New Customers	$12,533,333	$9,600,000	$19,200,000	$19,200,000	$48,000,000
4. Total Wire Footage	559,680	559,680	1,119,360	1,119,360	2,798,400
New Transformers (601)					
1. New transformers added	2,735	2,800	5,600	5,600	14,000
2. Cost per Transformer	$778	$900	$900	$900	
3. Cost of New Transformers	$2,127,173	$2,520,000	$5,040,000	$5,040,000	$12,600,000
New Meters (601)					
1. New Meters added	2,960	400	0	0	400
2. Cost per Meter	$72	$75	$0	$0	
3. Cost of New Meters	$213,120	$30,000	$0	$0	$30,000
New AMR Meters (601)					
1. New Meters added		2,800	6,400	6,400	15,600
2. Cost per Meter		$120	$120	$120	
3. Cost of New Meters		$336,000	$768,000	$768,000	$1,872,000
AMR Replacement Meters (601)					
1. New Meters added		20,000	30,000	0	50,000
2. Cost per Meter		$120	$120	$120	
3. Cost of New Meters		$2,400,000	$3,600,000	$0	$6,000,000
Service Upgrades (602)					
1. Number of Service Upgrades	301	300	600	600	1,500
2. Cost per Service Upgrade	$2,680	$1,000	$1,000	$1,000	
3. Cost of Service Upgrades	$179,441	$300,000	$600,000	$600,000	$1,500,000
Pole Changes - Replacement (606)					
1. Poles Changed	440	440	880	880	2,200
2. Cost per Pole Change	$2,098	$2,100	$2,100	$2,100	
3. Cost of Pole Changes	$386,741	$924,000	$1,848,000	$1,848,000	$4,620,000
Security Lights (701)					
1. New Security Lights Added	1,088	1100	2200	2200	5,500
2. Cost per Security Light	$450	$450	$450	$450	
3. Cost of Security Lights	$90,564	$495,000	$990,000	$990,000	$2,475,000
AMR Computer Equipment (702)					
1. Related Software and Hardware		$793,400	$850,000	$0	$1,643,400

* Actual costs based on 18 month history interpolated to 24 months

TABLE II-E-1 SUBSTATION LOAD TABLE

WINTER FORECAST LOAD IN kVA

SUBSTATION	KVA CAPACITY[1]	Jan-03	%LOAD 1/03	Jan-06	%LOAD 1/06	Jan-10	%LOAD 1/10	Jan-14	%LOAD 1/14	NOTE
3-M SUB	15,725	8,057	51.24	8,720	55.45	8,720	55.45	8,720	55.45	
ALCAN #1	18,144	4,800	26.46	4,899	27.00	4,899	27.00	4,899	27.00	
ALCAN #2	18,144	9,800	54.01	10,058	55.43	10,058	55.43	10,610	58.48	
BERLIN	7,470	5,646	75.58	6,272	39.89	7,702	48.98	8,843	56.24	2
BRIDGEPORT	31,050	15,490	49.89	18,592	59.88	20,401	65.70	23,042	74.21	
CHAPLIN	7,020	1,257	17.91	1,667	23.75	1,667	23.75	1,667	23.75	
CLAY LICK	15,725	8,296	52.76	10,051	63.92	12,646	80.42	14,311	91.01	
COLEMANSVILLE	18,144	7,351	40.51	8,195	45.17	10,142	55.90	11,626	64.08	
CROOKSVILLE	15,725	9,742	61.95	10,980	69.83	13,599	86.48	15,528	98.75	20
CYNTHIANA	18,144	12,113	66.76	13,220	72.86	15,331	84.50	10,356	57.08	
DAVIS	15,725	12,303	78.24	12,858	81.77	14,352	91.27	16,493	90.90	22
FAYETTE #1	18,144	15,050	82.95	16,412	90.45	17,108	94.29	17,250	95.07	
FAYETTE #2	18,144	11,010	60.68	12,712	70.06	13,250	73.03	14,128	77.87	
FOUR OAKS	15,725	6,777	43.10	7,593	48.29	9,226	58.67	10,608	67.46	
HEADQUARTERS	8,346	5,530	66.26	6,398	76.66	8,000	95.85	8,377	74.79	7
HICKORY PLAINS	25,920	19,246	74.25	21,961	84.73	19,432	74.97	23,097	89.11	
HOLLOWAY	18,144	12,390	68.29	9,144	50.40	12,285	67.71	9,990	55.06	
JACKSONVILLE	24,840	4,586	18.46	5,255	21.16	7,927	31.91	9,025	36.33	
LEES LICK	18,144	12,971	71.49	10,382	57.22	12,473	68.74	14,160	78.04	
MERCER CO. IND. PK.	15,725	3,277	20.84	3,396	21.60	3,426	21.79	3,448	21.93	
MILLERSBURG	7,862	4,576	58.20	5,296	67.36	6,516	82.88	7,039	89.53	
NEWBY	15,725	12,694	80.73	14,992	95.34	11,981	76.19	13,770	87.57	10
NICHOLASVILLE	18,144	12,898	71.09	8,353	46.04	10,988	60.56	7,387	40.71	
NINEVAH	15,725	6,572	41.79	6,529	41.52	8,118	51.63	9,336	59.37	
NORTH MADISON	18,144	4,836	26.65	7,125	39.27	10,992	60.58	14,815	81.65	
PPG	15,725	5,193	33.02	5,458	34.71	5,458	34.71	5,458	34.71	
SINAI	18,144	13,488	74.34	11,125	61.32	13,935	76.80	13,526	74.55	
SOUTH ELKHORN	15,725	5,520	35.10	9,267	58.93	11,323	72.01	12,945	82.32	6
SOUTH JESSAMINE	31,050	6,912	22.26	16,479	53.07	19,598	63.12	22,434	72.25	
VANARSDELL	18,144	12,234	67.43	14,076	77.58	13,596	74.93	4,837	26.66	13
WEST BEREA	18,144	12,358	68.11	14,480	79.81	8,296	45.72	6,560	36.16	8
WEST NICHOLASVILLE	25,920	19,079	73.61	23,777	91.73	12,732	49.12	16,172	62.39	9
POWELL TAYLOR	15,725	N/A	N/A	4,953	31.50	10,430	66.33	8,614	54.78	5, 15
OXFORD	18,140	N/A	N/A	6,638	36.59	10,187	56.16	13,121	72.33	3, 21
SOUTH POINT	31,050	N/A	N/A	2,563	N/A	6,361	20.49	9,464	30.48	4
WEST NICHOLASVILLE 2	25,920	N/A	N/A	N/A	N/A	17,206	66.38	18,997	73.29	9
WEST BEREA 2	20,000	N/A	N/A	N/A	N/A	11,034	55.17	12,241	61.21	8
NEWBY 2	15,725	N/A	N/A	N/A	N/A	6,331	40.26	7,267	46.21	10
DUNCANON	15,725	N/A	N/A	N/A	N/A	3,607	22.94	6,940	44.13	11
BIG HILL	25,920	N/A	N/A	N/A	N/A	7,882	30.41	9,057	34.94	12
VANARSDELL 2	15,725	N/A	N/A	N/A	N/A	3,903	24.82	7,688	48.89	13
EBENEZER	15,725	N/A	N/A	N/A	N/A	N/A	N/A	7,721	49.10	14
POWELL TAYLOR 2	15725	N/A	N/A	N/A	N/A	N/A	N/A	8598	54.68	15
WEST CYNTHIANA	25,920	N/A	N/A	N/A	N/A	N/A	N/A	11,069	42.70	16
NORTH NICHOLASVILLE	25,920	N/A	N/A	N/A	N/A	N/A	N/A	11,137	42.97	17
RUDDLES MILLS	15,725	N/A	N/A	N/A	N/A	N/A	N/A	3,039	19.33	18
BOONE GAP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	5,718	N/A	19

1. MAX Winter Capacity
2. Berlin sub upgrade in A block
3. Oxford MVA Substation built in A block. Relieves Lees Lick
4. South Point Substation built in A block. Relieves Davis
5. Powell Taylor Substation built in A block. Relieves Ninevah, Sinai, and Bridgeport
6. South Elkhorn sub upgrade in A block
7. Headquarters substation upgrade in A block
8. West Berea split bus in A block
9. West Nicholasville split bus built in B block
10. Newby split bus in B block
11. Duncanon Substation built in B block. Relieves West Berea
12. Big Hill Substation built in B block. Relieves Hickory Plains
13. Vanarsdell split bus in B block
14. Ebenezer Substation built in C block. Relieves Vanarsdell and Clay Lick
15. Powell Taylor split bus (25kV) in C block
16. West Cynthiana Substation built in C block. Relieves Cynthiana
17. North Nicholasville Substation built in C block. Relieves Nicholasville, West Nicholasville, and Holloway
18. Ruddles Mills Substation built in C block. Relieves Millersburg, Jacksonville, and Cynthiana
19. Boone Gap Metering Point added in C block. Relieves West Berea
20. Crooksville substation upgrade in C block
21. Oxford Substation upgraded to 20MVA in 2011
22. Added fans at Davis Substation

TABLE II-E-2 SUBSTATION LOAD TABLE

SUMMER FORECAST LOAD IN kVA

SUBSTATION	KVA CAPACITY[1]	Jul-02	%LOAD /02	Jul-05	%LOAD 7/05	Jul-09	%LOAD 7/09	Jul-13	%LOAD 7/13	NOTE
3-M SUB	11,077	9,628	86.92	9,700	87.57	9,700	87.57	9,700	87.57	
ALCAN #1	13,622	9,348	68.62	10,000	73.41	10,350	75.98	10,700	78.55	
ALCAN #2	13,622	11,828	86.83	12,391	90.96	12,796	93.93	13,200	96.90	
BERLIN	11,077	4,494	40.57	5,488	49.54	6,624	59.80	7,760	70.06	2
BRIDGEPORT	24,000	12,672	52.80	17,358	72.33	19,829	82.62	22,300	92.92	
CHAPLIN	4,945	1,096	22.16	1,600	32.36	1,650	33.37	1,700	34.38	
CLAY LICK	11,077	5,328	48.10	7,229	65.26	8,797	79.41	10,364	93.56	
COLEMANSVILLE	13,622	5,919	43.45	7,493	55.01	9,085	66.69	10,677	78.38	
CROOKSVILLE	11,077	5,959	53.80	7,624	68.83	9,209	83.14	10,794	55.47	20
CYNTHIANA	13,622	10,417	76.47	11,999	88.09	10,337	75.88	8,675	63.68	
DAVIS	11,077	6,606	59.64	7,888	71.21	9,057	81.77	10,226	75.07	22
FAYETTE #1	13,622	8,817	64.73	9,000	66.07	9,000	66.07	9,000	66.07	
FAYETTE #2	13,622	10,215	74.99	10,500	77.08	10,500	77.08	10,500	77.08	
FOUR OAKS	11,077	5,907	53.33	7,478	67.51	9,009	81.33	10,539	95.14	
HEADQUARTERS	6,266	4,205	67.11	5,513	87.98	6,354	57.36	7,194	64.95	7
HICKORY PLAINS	19,460	12,254	62.97	14,359	73.79	15,045	77.31	15,730	80.83	
HOLLOWAY	13,622	12,208	89.62	7,083	52.00	5,881	43.17	4,679	34.35	
JACKSONVILLE	19,200	2,857	14.88	3,755	19.56	4,896	25.50	6,037	31.44	
LEES LICK	13,622	8,377	61.50	5,267	38.67	6,346	46.58	7,424	54.50	
MERCER CO. IND. PK.	11,077	3,831	34.59	4,456	40.23	4,478	40.43	4,500	40.63	
MILLERSBURG	5,538	3,182	57.45	4,020	72.58	4,331	78.19	4,641	83.80	
NEWBY	11,077	6,289	56.78	8,231	74.31	5,849	52.80	6,884	62.15	10
NICHOLASVILLE	13,622	11,201	82.23	7,680	56.38	9,750	71.58	11,820	86.77	
NINEVAH	11,077	5,593	50.49	4,890	44.15	5,962	53.82	7,034	63.50	
NORTH MADISON	13,622	2,662	19.54	10,006	73.45	11,596	85.12	13,185	96.79	
PPG	11,077	5,443	49.14	5,789	52.26	6,095	55.02	6,400	57.78	
SINAI	13,622	9,596	70.44	6,963	51.12	7,633	56.03	8,303	60.95	
SOUTH ELKHORN	11,077	8,830	79.72	12,943	70.96	15,227	83.48	17,511	96.00	6
SOUTH JESSAMINE	24,000	4,518	18.83	14,717	61.32	14,232	59.30	13,747	57.28	
VANARSDELL	13,622	7,904	58.02	11,081	81.35	4,827	35.44	3,190	23.42	13
WEST BEREA	13,622	8,222	60.36	6,739	49.47	7,336	53.85	7,933	58.24	8
WEST NICHOLASVILLE	19,460	18,103	93.03	17,899	91.98	10,613	54.54	15,077	77.48	9
WEST BEREA 2	13,622	N/A	N/A	5,294	38.86	7,065	51.86	8,835	64.86	8
POWELL TAYLOR	11,077	N/A	N/A	2,931	26.46	4,120	37.19	5,308	47.92	5, 15
OXFORD	13,620	N/A	N/A	8,629	63.36	12,573	92.31	16,516	84.87	3, 21
SOUTH POINT	24,000	N/A	N/A	2,230	9.29	7,621	31.75	13,011	54.21	4
WEST NICHOLASVILLE 2	19,460	N/A	N/A	N/A	N/A	12,459	64.02	13,168	67.67	9
NEWBY 2	11,077	N/A	N/A	N/A	N/A	4,064	36.69	4,714	42.56	10
DUNCANON	11,077	N/A	N/A	N/A	N/A	3,438	31.04	6,876	62.07	11
BIG HILL	19,460	N/A	N/A	N/A	N/A	5,641	28.99	6,162	31.66	12
VANARSDELL 2	11,077	N/A	N/A	N/A	N/A	9,802	88.49	6,212	56.08	13
EBENEZER	11,077	N/A	N/A	N/A	N/A	N/A	N/A	6,582	59.42	14
POWELL TAYLOR 2	11,077	N/A	N/A	N/A	N/A	N/A	N/A	7,506	67.76	15
WEST CYNTHIANA	19,460	N/A	N/A	N/A	N/A	N/A	N/A	9,080	46.66	16
NORTH NICHOLASVILLE	19,460	N/A	N/A	N/A	N/A	N/A	N/A	14,079	72.35	17
RUDDLES MILLS	11,077	N/A	N/A	N/A	N/A	N/A	N/A	5,190	46.85	18
BOONE GAP	N/A	N/A	N/A	N/A	N/A	N/A	N/A	4,321	N/A	19

1. MAX Summer Capacity
2. Berlin sub upgrade in A block
3. Oxford MVA Substation built in A block. Relieves Lees Lick
4. South Point Substation built in A block. Relieves Davis
5. Powell Taylor Substation built in A block. Relieves Ninevah, Sinai, and Bridgeport
6. South Elkhorn sub upgrade in A block
7. Headquarters substation upgrade in A block
8. West Berea split bus in A block
9. West Nicholasville split bus built in B block
10. Newby split bus in B block
11. Duncanon Substation built in B block. Relieves West Berea
12. Big Hill Substation built in B block. Relieves Hickory Plains
13. Vanarsdell split bus in B block
14. Ebenezer Substation built in C block. Relieves Vanarsdell and Clay Lick
15. Powell Taylor split bus (25kV) in C block
16. West Cynthiana Substation built in C block. Relieves Cynthiana

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COST
OF DISTRIBUTION SYSTEM IMPROVEMENTS
FOR PREFERRED
LONG RANGE SYSTEM PLAN

Fixed Charge Rate = 13.99%
Present Worth Discount Factor =5.50%
Inflation Rate = 2.50%

Load Block	Year	Annual New Plant	Inflation Factor	Inflated New Plant	Inflated Plant Accumulated	Annual Cost	Present Worth Fac.	P. Worth Cost
	2004	$2,629,283	1.000	$2,629,283	$2,629,283	$367,837	1.00	$367,837
	2005	$2,629,283	1.025	$2,695,015	$5,324,298	$744,869	0.95	$706,037
A	2006	$2,629,283	1.051	$2,762,390	$8,086,689	$1,131,328	0.90	$1,016,444
	2007	$2,451,238	1.077	$2,639,715	$10,726,404	$1,500,624	0.85	$1,277,952
	2008	$2,451,238	1.104	$2,705,708	$13,432,112	$1,879,152	0.81	$1,516,883
	2009	$2,451,238	1.131	$2,773,351	$16,205,463	$2,267,144	0.77	$1,734,670
B	2010	$2,451,238	1.160	$2,842,685	$19,048,147	$2,664,836	0.73	$1,932,661
	2011	$3,117,338	1.189	$3,705,535	$22,753,683	$3,183,240	0.69	$2,188,276
	2012	$3,117,338	1.218	$3,798,174	$26,551,856	$3,714,605	0.65	$2,420,432
	2013	$3,117,338	1.249	$3,893,128	$30,444,984	$4,259,253	0.62	$2,630,639
C	2014	$3,117,338	1.280	$3,990,456	$34,435,440	$4,817,518	0.59	$2,820,322
Total		**$30,162,153**		**$34,435,440**		**$26,530,406**		**$18,612,155**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COST
OF LINE EXTENSIONS
FOR PREFERRED
LONG RANGE SYSTEM PLAN

Fixed Charge Rate = 13.99%
Present Worth Discount Factor =5.50%
Inflation Rate = 2.50%

Load Block	Year	Annual New Plant	Inflation Factor	Inflated New Plant	Inflated Plant Accumulated	Annual Cost	Present Worth Fac.	P. Worth Cost
	2004	$5,799,467	1.000	$5,799,467	$5,799,467	$811,345	1.00	$811,345
	2005	$5,799,467	1.025	$5,944,453	$11,743,920	$1,642,974	0.95	$1,557,322
A	2006	$5,799,467	1.051	$6,093,065	$17,836,985	$2,495,394	0.90	$2,241,993
	2007	$8,224,000	1.077	$8,856,349	$26,693,333	$3,734,397	0.85	$3,180,264
	2008	$8,224,000	1.104	$9,077,757	$35,771,090	$5,004,376	0.81	$4,039,616
	2009	$8,224,000	1.131	$9,304,701	$45,075,792	$6,306,103	0.77	$4,825,016
B	2010	$8,224,000	1.160	$9,537,319	$54,613,110	$7,640,374	0.73	$5,541,149
	2011	$7,111,500	1.189	$8,453,339	$63,066,449	$8,822,996	0.69	$6,065,252
	2012	$7,111,500	1.218	$8,664,672	$71,731,121	$10,035,184	0.65	$6,538,914
	2013	$7,111,500	1.249	$8,881,289	$80,612,410	$11,277,676	0.62	$6,965,423
C	2014	$7,111,500	1.280	$9,103,321	$89,715,731	$12,551,231	0.59	$7,347,874
Total		**$78,740,400**		**$89,715,731**		**$70,322,051**		**$49,114,169**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COST
OF SUBSTATION IMPROVEMENTS
FOR PREFERRED
LONG RANGE SYSTEM PLAN

Fixed Charge Rate = 10.90%
Present Worth Discount Factor = 6.26%
Inflation Rate = 2.50%

Load Block	Year	Annual New Plant	Inflation Factor	Inflated New Plant	Inflated Plant Accumulated	Annual Cost	Present Worth Fac.	P. Worth Cost
	2004	$827,333	1.000	$827,333	$827,333	$90,179	1.00	$90,179
	2005	$827,333	1.025	$848,017	$1,675,350	$182,613	0.94	$171,855
A	2006	$827,333	1.051	$869,217	$2,544,567	$277,358	0.89	$245,641
	2007	$678,000	1.077	$730,132	$3,274,699	$356,942	0.83	$297,501
	2008	$678,000	1.104	$748,385	$4,023,084	$438,516	0.78	$343,959
	2009	$678,000	1.131	$767,095	$4,790,179	$522,129	0.74	$385,415
B	2010	$678,000	1.160	$786,272	$5,576,451	$607,833	0.69	$422,246
	2011	$820,500	1.189	$975,317	$6,551,768	$714,143	0.65	$466,870
	2012	$820,500	1.218	$999,700	$7,551,467	$823,110	0.62	$506,407
	2013	$820,500	1.249	$1,024,692	$8,576,159	$934,801	0.58	$541,241
C	2014	$820,500	1.280	$1,050,309	$9,626,469	$1,049,285	0.54	$571,736
Total		**$8,476,000**		**$9,626,469**		**$5,996,910**		**$4,043,051**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COST
OF TRANSMISSION IMPROVEMENTS
FOR PREFERRED
LONG RANGE SYSTEM PLAN

Fixed Charge Rate = 12.52%
Present Worth Discount Factor = 6.26%
Inflation Rate = 2.50%

Load Block	Year	Annual New Plant	Inflation Factor	Inflated New Plant	Inflated Plant Accumulated	Annual Cost	Present Worth Fac.	P. Worth Cost
	2004	$311,733	1.000	$311,733	$311,733	$39,029	1.00	$39,029
	2005	$311,733	1.025	$319,527	$631,260	$79,034	0.94	$74,378
A	2006	$311,733	1.051	$327,515	$958,775	$120,039	0.89	$106,312
	2007	$252,000	1.077	$271,376	$1,230,151	$154,015	0.83	$128,367
	2008	$252,000	1.104	$278,161	$1,508,312	$188,841	0.78	$148,121
	2009	$252,000	1.131	$285,115	$1,793,427	$224,537	0.74	$165,744
B	2010	$252,000	1.160	$292,243	$2,085,670	$261,126	0.69	$181,397
	2011	$476,400	1.189	$566,290	$2,651,960	$332,025	0.65	$217,061
	2012	$476,400	1.218	$580,447	$3,232,407	$404,697	0.62	$248,984
	2013	$476,400	1.249	$594,958	$3,827,365	$479,186	0.58	$277,444
C	2014	$476,400	1.280	$609,832	$4,437,197	$555,537	0.54	$302,702
Total		**$3,848,800**		**$4,437,197**		**$2,838,066**		**$1,889,540**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COSTS
OF LINE LOSSES
FOR PREFERRED
LONG RANGE SYSTEM PLAN

Annual Demand Adj. = 52.0%
Present Worth Discount Factor = 5.50%
Annual Peak Load Factor = 63.0%
Initial Cost per peak kW = $79.29

2.0% Annual Wholesale Power Cost Increase

Year	Peak kW Losses	Annual kW Loss $	Present Worth Factor	P. Worth Cost of
2004	6228	$493,818	1.00	$493,818
2005	6670	$539,442	0.95	$511,319
2006	7111	$586,610	0.90	$527,041
2007	7584	$638,142	0.85	$543,450
2008	8057	$691,500	0.81	$558,191
2009	8530	$746,738	0.77	$571,355
2010	9002	$803,819	0.73	$582,967
2011	9166	$834,833	0.69	$573,895
2012	9330	$866,765	0.65	$564,783
2013	9494	$899,641	0.62	$555,645
2014	9656	$933,292	0.59	$546,377
		----------------		----------------
	Total	**$8,034,600**		**$6,028,841**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COST
OF DISTRIBUTION SYSTEM IMPROVEMENTS
FOR ALTERNATE
LONG RANGE SYSTEM PLAN

Fixed Charge Rate = 13.99%
Present Worth Discount Factor =5.50%
Inflation Rate = 2.50%

Load Block	Year	Annual New Plant	Inflation Factor	Inflated New Plant	Inflated Plant Accumulated	Annual Cost	Present Worth Fac.	P. Worth Cost
	2004	$3,372,850	1.000	$3,372,850	$3,372,850	$471,862	1.00	$471,862
	2005	$3,372,850	1.025	$3,457,171	$6,830,021	$955,520	0.95	$905,706
A	2006	$3,372,850	1.051	$3,543,601	$10,373,622	$1,451,270	0.90	$1,303,897
	2007	$2,490,500	1.077	$2,681,996	$13,055,618	$1,826,481	0.85	$1,555,456
	2008	$2,490,500	1.104	$2,749,046	$15,804,664	$2,211,072	0.81	$1,784,815
	2009	$2,490,500	1.131	$2,817,772	$18,622,436	$2,605,279	0.77	$1,993,388
B	2010	$2,490,500	1.160	$2,888,216	$21,510,652	$3,009,340	0.73	$2,182,512
	2011	$2,043,563	1.189	$2,429,154	$23,939,807	$3,349,179	0.69	$2,302,349
	2012	$2,043,563	1.218	$2,489,883	$26,429,690	$3,697,514	0.65	$2,409,296
	2013	$2,043,563	1.249	$2,552,130	$28,981,820	$4,054,557	0.62	$2,504,213
C	2014	$2,043,563	1.280	$2,615,933	$31,597,753	$4,420,526	0.59	$2,587,911
Total		**$28,254,802**		**$31,597,753**		**$28,052,599**		**$20,001,404**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COST
OF LINE EXTENSIONS
FOR ALTERNATE
LONG RANGE SYSTEM PLAN

Fixed Charge Rate = 13.99%
Present Worth Discount Factor =5.50%
Inflation Rate = 2.50%

Load Block	Year	Annual New Plant	Inflation Factor	Inflated New Plant	Inflated Plant Accumulated	Annual Cost	Present Worth Fac.	P. Worth Cost
	2004	$5,799,467	1.000	$5,799,467	$5,799,467	$811,345	1.00	$811,345
	2005	$5,799,467	1.025	$5,944,453	$11,743,920	$1,642,974	0.95	$1,557,322
A	2006	$5,799,467	1.051	$6,093,065	$17,836,985	$2,495,394	0.90	$2,241,993
	2007	$8,224,000	1.077	$8,856,349	$26,693,333	$3,734,397	0.85	$3,180,264
	2008	$8,224,000	1.104	$9,077,757	$35,771,090	$5,004,376	0.81	$4,039,616
	2009	$8,224,000	1.131	$9,304,701	$45,075,792	$6,306,103	0.77	$4,825,016
B	2010	$8,224,000	1.160	$9,537,319	$54,613,110	$7,640,374	0.73	$5,541,149
	2011	$7,111,500	1.189	$8,453,339	$63,066,449	$8,822,996	0.69	$6,065,252
	2012	$7,111,500	1.218	$8,664,672	$71,731,121	$10,035,184	0.65	$6,538,914
	2013	$7,111,500	1.249	$8,881,289	$80,612,410	$11,277,676	0.62	$6,965,423
C	2014	$7,111,500	1.280	$9,103,321	$89,715,731	$12,551,231	0.59	$7,347,874
Total		**$78,740,400**		**$89,715,731**		**$70,322,051**		**$49,114,169**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COST
OF SUBSTATION IMPROVEMENTS
FOR ALTERNATE
LONG RANGE SYSTEM PLAN

Fixed Charge Rate = 10.90%
Present Worth Discount Factor = 6.26%
Inflation Rate = 2.50%

Load Block	Year	Annual New Plant	Inflation Factor	Inflated New Plant	Inflated Plant Accumulated	Annual Cost	Present Worth Fac.	P. Worth Cost
	2004	$700,000	1.000	$700,000	$700,000	$76,300	1.00	$76,300
	2005	$700,000	1.025	$717,500	$1,417,500	$154,508	0.94	$145,405
A	2006	$700,000	1.051	$735,438	$2,152,938	$234,670	0.89	$207,835
	2007	$792,000	1.077	$852,897	$3,005,835	$327,636	0.83	$273,075
	2008	$792,000	1.104	$874,220	$3,880,055	$422,926	0.78	$331,730
	2009	$792,000	1.131	$896,075	$4,776,130	$520,598	0.74	$384,285
B	2010	$792,000	1.160	$918,477	$5,694,607	$620,712	0.69	$431,193
	2011	$947,000	1.189	$1,125,685	$6,820,293	$743,412	0.65	$486,005
	2012	$947,000	1.218	$1,153,828	$7,974,120	$869,179	0.62	$534,750
	2013	$947,000	1.249	$1,182,673	$9,156,793	$998,090	0.58	$577,885
C	2014	$947,000	1.280	$1,212,240	$10,369,033	$1,130,225	0.54	$615,838
Total		**$9,056,000**		**$10,369,033**		**$6,098,256**		**$4,064,302**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COST
OF TRANSMISSION IMPROVEMENTS
FOR ALTERNATE
LONG RANGE SYSTEM PLAN

Fixed Charge Rate = 12.52%
Present Worth Discount Factor = 6.26%
Inflation Rate = 2.50%

Load Block	Year	Annual New Plant	Inflation Factor	Inflated New Plant	Inflated Plant Accumulated	Annual Cost	Present Worth Fac.	P. Worth Cost
	2004	$48,000	1.000	$48,000	$48,000	$6,010	1.00	$6,010
	2005	$48,000	1.025	$49,200	$97,200	$12,169	0.94	$11,453
A	2006	$48,000	1.051	$50,430	$147,630	$18,483	0.89	$16,370
	2007	$707,200	1.077	$761,577	$909,207	$113,833	0.83	$94,876
	2008	$707,200	1.104	$780,616	$1,689,824	$211,566	0.78	$165,946
	2009	$707,200	1.131	$800,132	$2,489,955	$311,742	0.74	$230,116
B	2010	$707,200	1.160	$820,135	$3,310,091	$414,423	0.69	$287,889
	2011	$394,200	1.189	$468,580	$3,778,671	$473,090	0.65	$309,282
	2012	$394,200	1.218	$480,294	$4,258,965	$533,222	0.62	$328,057
	2013	$394,200	1.249	$492,302	$4,751,267	$594,859	0.58	$344,418
C	2014	$394,200	1.280	$504,609	$5,255,876	$658,036	0.54	$358,551
Total		**$4,549,600**		**$5,255,876**		**$3,347,433**		**$2,152,968**

BLUE GRASS ENERGY COOPERATIVE
PRESENT WORTH OF ANNUAL COSTS
OF LINE LOSSES
FOR ALTERNATE
LONG RANGE SYSTEM PLAN

Annual Demand Adj. = 52.0%
Present Worth Discount Factor = 5.50%
Annual Peak Load Factor = 63.0%
Initial Cost per peak kW = $79.29

2.0% Annual Wholesale Power Cost Increase

Year	Peak kW Losses	Annual kW Loss $	Present Worth Factor	P. Worth Cost of
2004	6228	$493,818	1.00	$493,818
2005	6677	$540,008	0.95	$511,856
2006	7125	$587,765	0.90	$528,079
2007	7592	$638,815	0.85	$544,024
2008	8059	$691,672	0.81	$558,329
2009	8526	$746,388	0.77	$571,087
2010	8991	$802,837	0.73	$582,254
2011	9181	$836,199	0.69	$574,834
2012	9371	$870,574	0.65	$567,265
2013	9561	$905,990	0.62	$559,566
2014	9749	$942,281	0.59	$551,640
		-------------------		---------------
	Total	**$8,056,346**		**$6,042,751**

III. ANALYSIS OF EXISTING SYSTEM

III.1 Purpose

The analysis of the existing system indicates where the various system improvement alternatives are most likely to be economical. The analysis provides insight into the development of a practical transition from the existing system to the proposed long-range system.

III.2 Summary of Analysis, Conclusion and Recommendations

An existing system analysis was performed for the substation areas that constitute the "rural" BGE system. The "rural system" does not include the major spot loads or in some cases, the substations that serve them. System voltage levels, conductor loading, system capacities and outage data indicate the level of performance for an electric distribution system. The physical condition of the existing system was examined with a review of the operation and maintenance programs. The most significant items in the recent *O&M Survey* were telephone retirements and NESC compliance for CATV attachments. The need for a computerized maintenance program was also addressed. A new mapping system with GPS technology will be implemented.

In general, the existing system is providing a good quality of service to all customers. The 2004-2006 Construction Work Plan was developed concurrently with this Long Range System Plan. Substation capacity is satisfactory for the existing system.

An aged conductor replacement program is ongoing. The new CWP calls for 111 circuit miles of aged and underrated conductor to be replaced. An outline for the continuation of the aged conductor replacement has been developed for this Long Range Planning Report.

The 2003 distribution model's voltage drop report indicates voltage levels and conductor thermal loading levels that are generally within the planning criteria guidelines. Areas where voltage levels and loading were unsatisfactory were noted and prioritized in the construction work plan.

III.3 System Growth Patterns

In order to apply the projected load levels to specific areas of the system, growth area patterns are developed. Information from the comprehensive plans for Anderson, Bourbon, Fayette, Franklin, Harrison, Jessamine, Madison, Mercer, and Scott counties were used to help determine future land use in the service area. Kentucky DOT highway improvement plans – within the service area - were also analyzed. A BGE system circuit diagram map was colored-coded based on the different rates of expected growth in the service area. Floodplains, recreational and large-scale agriculture areas tend to have much slower growth than the areas around towns that have major highway access and commercial/industrial jobs available. This load and growth rate data is applied to a distribution system analysis computer program (Windmil by Milsoft). The result is a system computer model with more specific growth areas. These computer models are used in the engineering analysis of the future system.

Much of the economy in the service area is agricultural in nature. Also, there are numerous small commercial loads. Several Industrial Parks continue to expand due to a large amount of available land, existing electrical capacity and the centralized location of much of the service area. Several large spot load areas have dedicated substations and/or circuits – and were not specifically analyzed as part of the "rural system" in the Long Range Planning Study.

The *2003 Anderson County Comprehensive Plan* projects the need for an additional 2,223 homes by 2010. Much of this residential growth (in the BGE service area) is to the west of the City of Lawrenceburg between Highway 44 and US 62. The plan indicates the increasing growth and traffic along Powell Taylor Road. The plan recommends that Powell Taylor road be upgraded or replaced. This LRP has recommended a new distribution substation in the Powell Taylor Road area.

The *1992 Bourbon County Comprehensive Plan* recommends that most of the growth within the county should occur in areas contiguous to existing urban uses – mainly in the Paris area. Agricultural preservation is a key topic in the plan's recommendations. BGE may still expect some additional residential clustered developments throughout its Bourbon service area.

The *2001 Lexington-Fayette Urban County Comprehensive Plan* indicates that the BGE service area is in the "South" planning area. Practically all of the BGE service area lies in the low density development area. Much of the available Fayette County service area is already developed.

The *2001 Franklin County Comprehensive Plan* indicates that rural activities should mainly be limited to agricultural and large-lot residential uses. Larger scale residential developments are recommended to occur just outside the core of Frankfort. Growth in the BGE area of the county is expected to be moderate.

The most recent *Harrison County Comprehensive Plan* discourages large-scale residential and commercial growth outside Cynthiana....except for a few designated communities. Large development along the new bypass is discouraged in order to promote safe and orderly traffic flow. Industrial growth is recommended to take place adjacent to existing industrial areas (as is the case west of Cynthiana).

With the maturing development in the southern Fayette County area, growth is continuing to move southward into Jessamine County. The *1996 Jessamine County Comprehensive Plan* indicated that the major growth corridor in the county would be US 27. Today, this is certainly true. From the Fayette County line southward, tremendous commercial and residential growth is being experienced. The 1996 plan suggested that US 27 should not develop to the point of impeding normal traffic flow. Clustered new developments, near existing developments are recommended. It is clear that the BGE service area along US 27 and US 68 is growing rapidly. The plan also discourages high-density development along US 68 due to the need for smooth traffic flow. However, both corridors have grown to the point that traffic flow is compromised at peak hours. Improvements will continue on US 27 with the eastern bypass. Reconstruction work is scheduled for US 68 from the Fayette County line to north of Wilmore.

The *1999 Madison County Comprehensive Plan* indicates that while numerous subdivisions have recently developed, they are widely dispersed over the county. Many of the developments have been on roads that the plan deems too narrow to allow proper traffic flow. Much of the BGE service area will continue to grow due to its proximity to the cities of Richmond and Berea. A new I-75 interchange will accelerate commercial and residential growth in its proximity. This interchange is halfway between Richmond and Berea. A new distribution substation is projected for this area in the LRP.

The *1997 Mercer County Comprehensive Plan* indicates that over one-third of the county's land is considered to be "Prime Farmland" by the USDA. Some clustered residential development is expected along the US 127 corridor. BGE provides service to the Mercer County Industrial Park. No major new loads are anticipated in the park at this time. BGE's growth in Mercer County will be scattered throughout its service area.

The Highway 62 area, east of the Toyota Manufacturing plant is projected to be the heart of BGE's growth in Scott County during the LRP period. Industrial and residential growth is occurring due to Toyota and the proximity to Bourbon County. A new substation is recommended in the Oxford area as this will be the projected load center between the Toyota-based growth to the west and the Bourbon County growth influx to the east.

The BGE service area in their remaining counties is expected to have scattered, moderate growth.

III.4 Existing System Performance

The capacity ratings and load data of the BGE substations are presented in this section. The system is winter peaking. Load data and transformer ratings are based on winter non-coincident peaks. Some areas have a significant summer load as well.

The record of BGE's service interruptions for the past five-year average is shown in Table II-E-2. The five-year average outage hours per consumer – through 2002 - is **2.68**. This value is below the minimum level that is considered acceptable by RUS.

TABLE II-E-2

	Power Supplier	Extreme Storm	Prearranged	All Other	Total
FIVE-YEAR AVE. OUTAGE HR/CONS.	0.48	1.00	0.04	1.16	2.68

A massive ice storm struck the system in February 2003. The overall hours per consumer for 2003 were 8.41. This storm was estimated to be a 100-year ice storm. Ice buildup of greater than two inches was not uncommon. This level of ice loading is many times beyond that required for typical RUS mechanical distribution line design.

As a result of two recent system consolidations, overall outage data was not completely available for the present BGE system.

Environmentally Sensitive Areas

A sizeable portion of the service area is agricultural land. A Borrower's Environmental Report has been prepared for the new construction work plan. State and federal environmental guidelines are followed during the maintenance and construction of the electric distribution system.

EXISTING SYSTEM SUBSTATION LOAD TABLE

	WINTER			SUMMER		
SUBSTATION	KVA CAPACITY	Jan-03	%LOAD 1/03	KVA CAPACITY	Jul-02	%LOAD /02
3-M SUB	15,725	8,057	51.24	11,077	9,628	86.92
ALCAN #1	18,144	4,800	26.46	13,622	9,348	68.62
ALCAN #2	18,144	9,800	54.01	13,622	11,828	86.83
BERLIN	7,470	5,646	75.58	11,077	4,494	40.57
BRIDGEPORT	31,050	15,490	49.89	24,000	12,672	52.80
CHAPLIN	7,020	1,257	17.91	4,945	1,096	22.16
CLAY LICK	15,725	8,296	52.76	11,077	5,328	48.10
COLEMANSVILLE	18,144	7,351	40.51	13,622	5,919	43.45
CROOKSVILLE	15,725	9,742	61.95	11,077	5,959	53.80
CYNTHIANA	18,144	12,113	66.76	13,622	10,417	76.47
DAVIS	15,725	12,303	78.24	11,077	6,606	59.64
FAYETTE #1	18,144	15,050	82.95	13,622	8,817	64.73
FAYETTE #2	18,144	11,010	60.68	13,622	10,215	74.99
FOUR OAKS	15,725	6,777	43.10	11,077	5,907	53.33
HEADQUARTERS	8,346	5,530	66.26	6,266	4,205	67.11
HICKORY PLAINS	25,920	19,246	74.25	19,460	12,254	62.97
HOLLOWAY	18,144	12,390	68.29	13,622	12,208	89.62
JACKSONVILLE	24,840	4,586	18.46	19,200	2,857	14.88
LEES LICK	18,144	12,971	71.49	13,622	8,377	61.50
MERCER CO. IND. PK.	15,725	3,277	20.84	11,077	3,831	34.59
MILLERSBURG	7,862	4,576	58.20	5,538	3,182	57.45
NEWBY	15,725	12,694	80.73	11,077	6,289	56.78
NICHOLASVILLE	18,144	12,898	71.09	13,622	11,201	82.23
NINEVAH	15,725	6,572	41.79	11,077	5,593	50.49
NORTH MADISON	18,144	4,836	26.65	13,622	2,662	19.54
PPG	15,725	5,193	33.02	11,077	5,443	49.14
SINAI	18,144	13,488	74.34	13,622	9,596	70.44
SOUTH ELKHORN	15,725	5,520	35.10	11,077	8,830	79.72
SOUTH JESSAMINE	31,050	6,912	22.26	24,000	4,518	18.83
VANARSDELL	18,144	12,234	67.43	13,622	7,904	58.02
WEST BEREA	18,144	12,358	68.11	13,622	8,222	60.36
WEST NICHOLASVILLE	25,920	19,079	73.61	19,460	18,103	93.03

DISTRIBUTION LINE AND EQUIPMENT COSTS

Construction cost estimates are shown in Table II-B-1. Cost summaries for distribution equipment are shown in Table II-B-2.

Table II-B-1 Line Construction Cost Estimates
2004 Dollars/Mile

SIZE	TYPE	COST
1/0 ACSR	CONV 3-PH	$55,000
336.4 ACSR	CONV 3-PH	$70,000
556 MCM	CONV 3-PH	$85,000
DCT 336.4 ACSR	CONV 3-PH	$85,000
#2 ACSR	CONV V-PH	$40,000
1/0 ACSR	CONV V-PH	$47,000
#2 ACSR	CONV 1-PH	$25,000
1/0 ACSR	CONV 1-PH	$30,000
25kV Re-insulation	3-PHASE	$13,500
25kV Re-insulation	1-PHASE	$4,500
1/0 ALUG	1-PHASE*	$75,000
1/0 ALUG	3-PHASE	$144,500
500 MCM	3-PHASE	$238,000

*as replacement

Table II-B-2 Distribution Equipment Cost Estimated
2004 Unit Costs

DEVICE	TYPE	COST
V.Regulators (3)	219 amp	$37,500
V.Regulators (3)	150 amp	$32,100
V.Regulators (3)	100 amp	$30,000
V.Regulators (1)	50 amp	$9,000
300 kVAR Capacitors	3-PHASE	$3,500
450 kVAR Capacitors	3-PHASE	$4,000
600 kVAR Capacitors	3-PHASE	$4,500
333 kVA Transformer	1-PHASE	$4,600
500 kVA Transformer	1-PHASE	$9,200

IV. LONG RANGE SYSTEM PLAN

IV.1 Planning Criteria

1) The minimum secondary transformer voltage on distribution lines is 118 volts (120 volt base, 126 volts at source) after re-regulation. Any new voltage regulators added to the system will not be cascaded, but existing cascaded regulators may remain.

2) Primary conductors over 75% of their thermal rating will be considered for change out.

3) The following equipment will not be thermally loaded by more than the percentage shown:
   a) Distribution Transformers 130% winter; 100% summer
   b) Voltage Regulators 130% winter; 100% summer
   c) Autotransformers 130% winter; 100% summer
   d) Reclosers and Fuses 70% winter; 70% summer

4) Conversions to multiphase are to correct voltage drop and phase balance. Line sections operating at either 12.5/7.2kV or 24.9/14.4kV with load current exceeding 40 amps will be considered for multiphasing. Operation and engineering practices used to develop the loading criteria are based on a single-phase line interruption that may cause an operation of the ground trip relay on three phase oil circuit reclosers.

5) Three phase tie points between substations are to have air break switches.

6) Deteriorated conductors will be replaced based on Long Range Plan schedule. This schedule will be based on outage data and recommendations from the operations department. Poles and/or crossarms will be replaced if found to be physically deteriorated by visual inspection or testing.

7) New primary conductor sizes are to be determined on a case by case basis using the Economic Conductor Analysis method. The standard Overhead conductor sizes are #2 ACSR, 1/0 ACSR, 336.4, and 556 MCM ACSR. The standard Underground conductor size is 1/0, 4/0, and 500 MCM ALUG.

FINANCIAL CRITERIA

- ***Cost of Capital = 5.5%***
- ***Inflation = 2.5%***
- ***Present Worth Factor = 5.5%***
- ***Depreciation = 3.1%***
- ***O&M = 4.52%***
- ***Tax & Ins = 0.87%***
- ***TOTAL ANNUAL FIXED CHARGE RATE = 13.99%***

IV.2 Preferred Long Range Plan

The preferred plan recommends ten new substations and five existing substation transformer additions. Line conversions and replacements will total 400 miles.

Portions of the Fox Creek District that serve 600 customers will be converted to operate at 25kV/14.4kV distribution voltage. No voltage conversions are recommended in any of the other districts.

Present worth cost estimates and comparisons were formulated for transmission and substation facilities. These costs were added to each overall plan respectively - in order to evaluate each plan on a one-system concept. The actual plant addition figures for BGE do not include transmission or substation costs.

Voltage regulators are utilized in the early and middle stages of the plan. However, more permanent improvements are recommended in the Long Range load level.

NOTE: A list of all improvements for each load level is included in this section.

In the **A Load Level**, which coincides with the construction work plan, three new substations will be constructed. Three substations will have capacity upgrades and one substation will operate a second transformer in a split-bus configuration. There will be 111 miles of conductor upgraded or replaced.

In the **B Load Level**, two new substations are recommended. One substation will have a capacity upgrade and three substations will operate a second transformer in a split-bus configuration. There will be 173 miles of conductor upgraded or replaced.

In the **C "LONG RANGE" Load Level**, five new substations are recommended. Three substations will have capacity upgrades and one substation will operate a second transformer in a split-bus configuration. There will be 112 miles of conductor upgraded or replaced.

IV.3 Alternate Long Range Plan

The alternate plan recommends ten new substations and seven existing substation transformer additions. Line conversions and replacements will total 411 miles.

Portions of the Fox Creek District and an area in the Harrison District that together serve 2,300 customers will be converted to operate at 25kV/14.4kV distribution voltage. BGE management does not desire voltage conversions in any of the other districts besides Fox Creek. The voltage conversion in the Harrison District was a much more expensive and less efficient scenario than the preferred construction of the Oxford Substation.

In the **A Load Level**, no new substations will be constructed. Three substations will have capacity upgrades and four substations will operate a second transformer in a split-bus configuration. There will be 118 miles of conductor upgraded or replaced.

In the **B Load Level**, four new substations are recommended. One substation will have a capacity upgrade and two substations will operate a second transformer in a split-bus configuration. There will be 175 miles of conductor upgraded or replaced.

In the **C "LONG RANGE" Load Level**, six new substations are recommended. One substation will have a capacity upgrade and one substation will operate a second transformer in a split-bus configuration. There will be 118 miles of conductor upgraded or replaced.

PREFERRED
PLAN
LOAD LEVEL A (2004-2005)
2004 DOLLARS

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
FOX CREEK						
	Bridgeport					
001	2035, 2442	1 ph 8A CWC	1 ph #2 ACSR	2.6	$25,000	$65,000
	2035, 2442	25kV conversion	transformers	20.0	$850	$17,000
	Load of 2105	Add 300 kVAR	3 ph Capacitor	1.0	$3,500	$3,500
	Ninevah					
002	2437-2433, 2061, 2430	3 ph DCT #2 ACSR	3 ph DCT 336 ACSR	2.1	$85,000	$178,500
003	2427-2297A	3 ph #2 ACSR	3 ph 336.4 ACSR	5.2	$70,000	$364,000
004	2057	1 ph #4 ACSR	1 ph #2 ACSR	5.5	$25,000	$137,500
	2057	25kV conversion	transformers	53.0	$850	$45,050
	Source of 2057	Add (1) 500 kVA	Step transformers	1.0	$9,200	$9,200
	Sinai					
005	2511-2395	3 ph #4 ACSR	3 ph 336.4 ACSR	4.2	$70,000	$294,000
006	2394-2429	3 ph #4 ACSR	3 ph 1/0 ACSR	4.3	$55,000	$236,500
007	2389	1 ph 8A CWC	3 ph 1/0 ACSR	1.5	$55,000	$82,500
008	2367-2345	1 ph #4 ACSR	3 ph 1/0 ACSR	4.4	$55,000	$242,000
009	2302	1 ph 8A CWC	3 ph 1/0 ACSR	0.6	$55,000	$33,000
010	2462	1 ph 8A CWC	3 ph 1/0 ACSR	2.3	$55,000	$126,500
011	2326	1 ph 8A CWC	V ph 1/0 ACSR	2.3	$55,000	$126,500
	Vanarsdell					
012	2176	1 ph 1/0 ACSR	3 ph 1/0 ACSR	2.9	$55,000	$159,500
013	2214, 2212	1 ph #4 ACSR	3 ph 1/0 ACSR	5.2	$55,000	$286,000
	Source of 2186	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	Source of 2187	Add (3) 150A	Voltage Regulator	1.0	$32,100	$32,100
	Source of 2239	Add (2) 100A	Voltage Regulator	1.0	$20,000	$20,000
	Source of 2265	Add (3) 100A	Voltage Regulator	1.0	$30,000	$30,000
	Load of 2457	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Clay Lick					
014	2142	1 ph #4 ACSR	3 ph 1/0 ACSR	1.2	$55,000	$66,000
015	2155A	1 ph 8A CWC	3 ph 1/0 ACSR	3.5	$55,000	$192,500
016	2119	1 ph 8A CWC	3 ph 1/0 ACSR	2.5	$55,000	$137,500
017	2147	1 ph 8A CWC	V ph #2 ACSR	1.8	$40,000	$72,000
	Source of 2159	Add (3) 150A	Voltage Regulator	1.0	$32,100	$32,100
	Source of 2137	Add (3) 100A	Voltage Regulator	1.0	$30,000	$30,000
	Source of 2126	Add (3) 100A	Voltage Regulator	1.0	$30,000	$30,000
	Load of 2151	Add 300 kVAR	3 ph Capacitor	1.0	$3,500	$3,500
	Powell Taylor					
018	2296	3 ph #4 ACSR	3 ph DCT 336 ACSR	1.1	$85,000	$93,500
019	2293	3 ph #4 ACSR	3 ph 336.4 ACSR	3.0	$70,000	$210,000
020	2094	1 ph 8A CWC	1 ph #2 ACSR	3.0	$25,000	$75,000
	Load of 2102	Add (3) 1667 kVA	Step transformers	1.0	$60,000	$60,000
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	3.0	$184,000	$552,000
	Transmission tap at sub site					$36,000
HARRISON						
	Cynthiana					
021	4315	1 ph #4 ACSR	3 ph 1/0 ACSR	0.5	$55,000	$27,500
022	4693	1 ph 1/0 URD	1 ph 1/0 URD	1.3	$75,000	$97,500
	Load of 4299	Add 600 kVAR	3 ph Capacitor	1.0	$4,500	$4,500
	Headquarters					
023	4345-4337	3 ph #4 ACSR	3 ph 336.4 ACSR	4.9	$70,000	$343,000
	Upgrade Substation	11.2MVA	Transformer	1		$200,000
	Lees Lick					
024	4504-4748	1 ph 8A CWC	3 ph 1/0 ACSR	2.7	$55,000	$148,500
025	4661	1 ph #4 ACSR	3 ph 1/0 ACSR	0.4	$55,000	$22,000
026	4592	1 ph #4 ACSR	3 ph 1/0 ACSR	0.1	$55,000	$5,500
027	4499	1 ph 8A CWC	3 ph 1/0 ACSR	0.5	$55,000	$27,500
	Source of 4675	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	Colemansville					
028	4161	1 ph #4 ACSR	3 ph 1/0 ACSR	0.9	$55,000	$49,500
029	4241	1 ph 8A CWC	V ph #2 ACSR	0.8	$40,000	$32,000
030	4250, 4249	1 ph 8A CWC	3 ph 1/0 ACSR	1.0	$55,000	$55,000
	Source of 4178	Add (1) 50A	Voltage Regulator	1.0	$9,000	$9,000

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Four Oaks					
031	H4131, 4743, 4130	1 ph 8A CWC	3 ph 1/0 ACSR	0.8	$55,000	$44,000
	Berlin					
032	4784, 4007	1 ph #4 ACSR	3 ph 1/0 ACSR	1.9	$55,000	$104,500
033	4014	1 ph 8A CWC	V ph #2 ACSR	0.8	$40,000	$32,000
034	4037	1 ph 8A CWC	V ph #2 ACSR	0.5	$40,000	$20,000
035	4016	1 ph #4 ACSR	3 ph 1/0 ACSR	0.7	$55,000	$38,500
036	4015	3 ph #4 ACSR	3 ph 336.4 ACSR	1.0	$70,000	$70,000
	Upgrade Substation	11.2MVA	Transformer	1		$200,000
	Millersburg					
037	4418, 4991, 4416	1 ph #2 ACSR	3 ph 1/0 ACSR	0.8	$55,000	$44,000
038	4403	1 ph #2 ACSR	3 ph 1/0 ACSR	0.7	$55,000	$38,500
	Jacksonville					
	Load of 4532	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	Oxford					
039	DCT1, DCT 2		3 ph DCT 336 ACSR	1.0	$85,000	$85,000
040	4638, 4650	1 ph 8A CWC	3 ph 336.4 ACSR	1.3	$70,000	$91,000
		69-12.47/7.2kV	11.2MVA w/fans			$525,000
		69kV	Transmission	0.8	$184,000	$147,200
	Transmission tap at sub site					$36,000
NICHOLASVILLE & MADISON						
	Nicholasville					
041	171 ext		3 ph 336.4 ACSR	0.2	$70,000	$14,000
	Holloway					
042	20	1 ph #4 ACSR	3 ph 1/0 ACSR	2.5	$55,000	$137,500
043	406	1 ph 1/0 URD	1 ph 1/0 URD	1.2	$75,000	$90,000
044	487	1 ph 1/0 URD	1 ph 1/0 URD	0.8	$75,000	$60,000
	West Nicholasville					
045	New Getaway		3 ph 500 MCM UG	0.1	$238,000	$23,800
046	New Feeder		3 ph 336.4 ACSR	0.4	$70,000	$28,000
047	430		3 ph 336.4 ACSR	0.9	$70,000	$63,000
	Davis					
048	79	3 ph 1/0 ACSR	3 ph 336.4 ACSR	1.0	$70,000	$70,000
	Fayette One					
049	All Getaways	3 ph 4/0 URD	3 ph 500 MCM UG	0.4	$238,000	$95,200
050	456, 478	1 ph 1/0 URD	1 ph 1/0 URD	0.9	$75,000	$67,500
051	453	1 ph 1/0 URD	1 ph 1/0 URD	0.4	$75,000	$30,000
052	460	1 ph 1/0 URD	1 ph 1/0 URD	0.6	$75,000	$45,000
053	454	1 ph 1/0 URD	1 ph 1/0 URD	0.6	$75,000	$45,000
054	445	1 ph 1/0 URD	1 ph 1/0 URD	0.2	$75,000	$15,000

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Fayette Two					
055	477, 479, 504	1 ph 1/0 URD	1 ph 1/0 URD	1.3	$75,000	$97,500
	Newby					
056	216, 232	1 ph #4 ACSR	3 ph 1/0 ACSR	1.0	$55,000	$55,000
	Source of 229	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	Hickory Plains					
057	303, 302	1 ph #4 ACSR	3 ph 336.4 ACSR	1.9	$70,000	$133,000
058	287A, 287	1 ph #4 ACSR	3 ph 1/0 ACSR	0.8	$55,000	$44,000
059	285A-389	3 ph 4/0 ACSR	3 ph 336.4 ACSR	2.5	$70,000	$175,000
060	415	1 ph 6A CWC	3 ph 1/0 ACSR	0.5	$55,000	$27,500
061	307, 310	1 ph #4 ACSR	3 ph 1/0 ACSR	2.1	$55,000	$115,500
	South Elkhorn					
062	510	1 ph 1/0 URD	1 ph 1/0 URD	0.4	$75,000	$30,000
	Upgrade Substation	15 MVA	Transformer w/ fans	1		$173,000
	Crooksville					
063	251	1 ph #4 ACSR	3 ph 1/0 ACSR	0.4	$55,000	$22,000
064	297	1 ph #4 ACSR	3 ph 1/0 ACSR	2.2	$55,000	$121,000
065	440	1 ph #4 ACSR	3 ph 1/0 ACSR	0.3	$55,000	$16,500
	Source of 249	Add (1) 50A	Voltage Regulator	1.0	$9,000	$9,000
	South Jessamine					
066	104	1 ph #4 ACSR	3 ph 1/0 ACSR	0.9	$55,000	$49,500
067	556 xpress		3 ph 556 ACSR	0.4	$85,000	$34,000
068	156	1 ph 6A CWC	V ph 1/0 ACSR	1.5	$47,000	$70,500
	North Madison					
069	174	3 ph 1/0 ACSR	3 ph DCT 336 ACSR	2.0	$85,000	$170,000
070	173	1 ph #4 ACSR	3 ph 336.4 ACSR	1.3	$70,000	$91,000
071	188	1 ph #4 ACSR	3 ph 1/0 ACSR	1.1	$55,000	$60,500
	South Point					
072	Getaways		3 ph 500 MCM UG	0.8	$238,000	$190,400
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	0.5	$184,000	$92,000
		Transmission tap at sub site				$36,000
	West Berea 2					
	Split Bus	69-25/14.4 kV	Add 11.2 MVA			$350,000
		Transmission tap at sub site				$36,000

PREFERRED
PLAN
LOAD LEVEL B (2006-2009)
2004 DOLLARS

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
FOX CREEK						
	Bridgeport					
073	2052	1ph 8A CWC	3ph 1/0 ACSR	3.3	$55,000	$181,500
074	2020, 2021, 2018, 2030, 2029, 2027,	3ph #4ACSR	3ph 1/0 ACSR	7.3	$55,000	$401,500
075	2434	1ph#4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
076	2043	1ph 8A CWC	1 ph #2 ACSR	1.8	$25,000	$45,000
077	2023, 2440, 2478	1 ph 8A CWC	1 ph #2 ACSR	3.5	$25,000	$87,500
078	2082	1 ph #4 ACSR	3 ph 1/0 ACSR	2.1	$55,000	$115,500
079	2085	1 ph #4 ACSR	3 ph 336.4 ACSR	2.3	$70,000	$161,000
	Ninevah					
080	2079, 2080, 2475	3ph #4ACSR	3ph 336 ACSR	2.5	$70,000	$175,000
081	2074, 2076	3ph #4ACSR	3ph 1/0 ACSR	4.8	$55,000	$264,000
	Sinai					
082	2091	1ph 8A CWC	3ph 1/0 ACSR	2.0	$55,000	$110,000
083	2273	1ph#4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
084	2304	1ph 8A CWC	3ph 1/0 ACSR	1.8	$55,000	$99,000
085	2327	1ph 8A CWC	3ph 1/0 ACSR	2.3	$55,000	$126,500
086	2331	1ph 8A CWC	3ph 1/0 ACSR	1.4	$55,000	$77,000
087	2408, 2409	1ph 8A CWC	3ph 1/0 ACSR	1.9	$55,000	$104,500
088	2377	1ph#4ACSR	3ph 1/0 ACSR	0.5	$55,000	$27,500
089	2280, 2279	1ph 8A CWC	1 ph #2 ACSR	1.9	$25,000	$47,500
090	2365-2363	1ph 8A CWC	3ph 1/0 ACSR	2.5	$55,000	$137,500
091	2385-2388	1 ph 8A CWC	1 ph #2 ACSR	6.0	$25,000	$150,000
	Load of 2417	Add (3) 219A	Voltage Regulator	1	$37,500	$37,500
	Vanarsdell					
092	2219	1 ph #4ACSR	3ph 1/0 ACSR	1.1	$55,000	$60,500
093	2230	1 ph #4 ACSR	V ph #2 ACSR	1.6	$40,000	$64,000
	Load of 2270	Add (3) 150A	Voltage Regulator	1	$32,100	$32,100

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Clay Lick					
094	2157	3ph 1/0 ACSR	3ph DCT 336ACR	0.9	$85,000	$76,500
095	2158	1ph#4ACSR	3ph 336 ACSR	2.5	$70,000	$175,000
096	2506	1ph 8A CWC	1 ph #2 ACSR	0.5	$25,000	$12,500
097	2400,2139	1ph#4ACSR	3ph 1/0 ACSR	2.2	$55,000	$121,000
098	2121	1ph#4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
099	2464, 2447, 2448	1ph#2ACSR	3ph 1/0 ACSR	2.6	$55,000	$143,000
100	2133	1 ph #4 ACSR	3 ph 1/0 ACSR	2.7	$55,000	$110,000
101	2155B	1 ph 8A CWC	1 ph #2 ACSR	2.9	$25,000	$72,500
102	2149, 2146, 2145, 2144	1 ph 8A CWC	1 ph #2 ACSR	5.2	$25,000	$130,000
	Powell Taylor					
103	2295, 2294	1 ph 8A CWC	3 ph 1/0 ACSR	2.5	$55,000	$137,500
104	2093	1 ph 8A CWC	3 ph 1/0 ACSR	0.4	$55,000	$22,000
105	2099, 2092	1 ph 8A CWC	1 ph #2 ACSR	1.3	$25,000	$32,500
106	2297 DCT	3 ph #2 ACSR	3ph DCT 336ACR	0.5	$85,000	$42,500
	Vanarsdell 2					
107	2480, 2206	1 ph #4ACSR	3ph 1/0 ACSR	2.9	$55,000	$159,500
108	2199	1ph#4ACSR	3 ph #2 ACSR	6.2	$47,000	$291,400
	2461-2458	25kV conversion	3 ph re-insulation	6.7	$13,500	$90,450
		25kV conversion	transformers	10.0	$850	$8,500
	Load of 2458	Add (3) 1667kVA	Step transformers	3	$20,000	$60,000
	Split Bus	69-25/14.4 kV	Add 11.2 MVA			$350,000
	Transmission tap at sub site					$36,000
HARRISON						
	Cynthiana					
109	4547	1 ph #4ACSR	3ph 336 ACSR	0.5	$70,000	$35,000
110	4292, 4293	3 ph 3/0 ACSR	3ph DCT 336ACR	0.5	$85,000	$42,500
111	4327	1ph#4ACSR	3ph 336 ACSR	0.9	$70,000	$63,000
	Headquarters					
112	4371, 4369	1 ph #4ACSR	V ph #2 ACSR	1.2	$40,000	$48,000
113	4431, 4432	1 ph #4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
114	4488	1 ph #4ACSR	3ph 1/0 ACSR	2.1	$55,000	$115,500
	Lees Lick					
115	4586, 4587, 4588	1 ph #4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
116	4621	1 ph #4 ACSR	3 ph 1/0 ACSR	1.8	$55,000	$99,000

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Colemansville					
117	4156, 4780	1 ph #4ACSR	V ph #2 ACSR	2.4	$40,000	$96,000
118	4189	1 ph #2ACSR	3ph 1/0 ACSR	2.3	$55,000	$126,500
119	4201,4756	1 ph #4ACSR	V ph #2 ACSR	0.6	$40,000	$24,000
120	4249	3ph 8A CWC	3ph 1/0 ACSR	0.5	$55,000	$27,500
121	4159	1 ph #4 ACSR	V ph #2 ACSR	1.5	$40,000	$60,000
	Load of 4179	Add (3) 100A	Voltage Regulator	1	$30,000	$30,000
	Four Oaks					
122	4077, 4075, 4074	1ph 8A CWC	3ph 336 ACSR	1.8	$70,000	$126,000
123	4151, 4149	1ph 8A CWC	3ph 1/0 ACSR	2.6	$55,000	$143,000
124	4150	1ph 8A CWC	1 ph #2 ACSR	1.8	$25,000	$45,000
125	4089, 4772, 4086-4088	1 ph #4 ACSR	1 ph #2 ACSR	3.6	$25,000	$90,000
	Berlin					
126	4011, 4009, 4006, 4004, 4002	3ph #4ACSR	3ph 336 ACSR	3.8	$70,000	$266,000
	Millersburg					
127	4423, 4424	1 ph #4ACSR	3ph 336 ACSR	1.0	$70,000	$70,000
	Jacksonville					
128	4568	1 ph #4ACSR	3ph 336 ACSR	1.0	$70,000	$70,000
	Oxford					
129	4752, 4595	1ph 8A CWC	3ph 1/0 ACSR	1.2	$55,000	$66,000
130	4613	1 ph #4ACSR	3ph 336 ACSR	0.6	$70,000	$42,000
131	4581,4584	1 ph #4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
NICHOLASVILLE & MADISON						
	Nicholasville					
132	59	1 ph #4ACSR	3ph 1/0 ACSR	1.7	$55,000	$93,500
	Holloway					
133	21	3 ph #4ACSR	3ph 336 ACSR	0.9	$55,000	$49,500
134	3	1 ph #4ACSR	3ph 1/0 ACSR	1.1	$55,000	$60,500
	Source of 17	Add (1)50A	Voltage Regulator	1	$9,000	$9,000
	West Nicholasville					
135	25	1 ph #4ACSR	Vph 1/0 ACSR	1.1	$47,000	$51,700
136	150	1 ph #4ACSR	V ph #2 ACSR	0.9	$40,000	$36,000
137	154	1 ph #4ACSR	Vph 1/0 ACSR	0.6	$47,000	$28,200

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Davis					
138	42	1 ph #4ACSR	3ph 1/0 ACSR	1.7	$55,000	$93,500
	Newby					
139	235, 233	3 ph 1/0 ACSR	3ph DCT 336ACR	1.9	$85,000	$161,500
140	205	3 ph 1/0 ACSR	3ph 336 ACSR	0.9	$70,000	$63,000
141	247	1 ph 6A CWC	3 ph 1/0 ACSR	3.0	$55,000	$165,000
	West Berea					
142	332	1 ph #4ACSR	3ph 1/0 ACSR	1.7	$55,000	$93,500
143	240	1 ph #4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
	Hickory Plains					
144	305	1 ph #4ACSR	3ph 336 ACSR	2.7	$70,000	$189,000
145	309	1 ph #4ACSR	3ph 336 ACSR	1.3	$70,000	$91,000
	South Elkhorn					
146	1	1 ph #4ACSR	3ph 1/0 ACSR	1.3	$55,000	$71,500
147	407	1 ph #4 ACSR	3 ph 1/0 ACSR	1.3	$55,000	$71,500
	Upgrade Substation	25MVA	Transformer	1		$350,000
	Crooksville					
148	249	1 ph #4ACSR	3ph 1/0 ACSR	2.0	$55,000	$110,000
149	254	1 ph #4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
150	299	1 ph #4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
151	365	1 ph #4ACSR	V ph #2 ACSR	1.3	$40,000	$52,000
152	292	1 ph #4ACSR	3ph 1/0 ACSR	2.8	$55,000	$154,000
	Load of 294	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	South Jessamine					
153	OH 422, 141, 138	3 ph 4/0 ACSR	3ph DCT 336ACR	1.9	$85,000	$161,500
154	OH 571, 126	1 ph #4ACSR	3ph 1/0 ACSR	2.4	$55,000	$132,000
155	145 Extended		3ph 336 ACSR	0.4	$70,000	$28,000
156	157	1 ph 6A CWC	V ph 1/0 ACSR	1.5	$47,000	$70,500
157	101	1 ph 1/0 ACSR	V ph 1/0 ACSR	1.3	$47,000	$61,100
	North Madison					
158	186	1 ph #4ACSR	3ph 1/0 ACSR	1.4	$55,000	$77,000
159	172	3 ph 1/0 ACSR	3ph 336 ACSR	2.3	$70,000	$161,000
160	184	3 ph #4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
	West Berea 2					
161	321	1 ph 1/0 ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
West Nicholasville 2						
	Split Bus	69-12.47/7.2kV	20 MVA			$375,000
	Transmission tap at sub site					$36,000

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Newby 2					
	Split Bus	69-12.47/7.2kV	Add 11.2 MVA			$350,000
	Transmission tap at sub site					$36,000
	Duncanon					
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	1.5	$184,000	$276,000
	Transmission tap at sub site					$36,000
	Big Hill					
162	279	3 ph #4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
163	287	3 ph #4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
		69-12.47/7.2kV	20MVA			$570,000
		69kV	Transmission	3.0	$184,000	$552,000
	Transmission tap at sub site					$36,000

PREFERRED PLAN
LOAD LEVEL C (2010-2014)
2004 DOLLARS

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
FOX CREEK						
	Bridgeport					
164	2002	1ph 1/0 ACSR	3ph 1/0 ACSR	2.3	$55,000	$126,500
165	2113	1ph 8A CWC	3ph 1/0 ACSR	1.9	$55,000	$104,500
166	2024	1ph#4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
167	2031, 2441, 2026	1ph 8A CWC	1 ph #2 ACSR	3.8	$25,000	$95,000
	2031, 2441, 2026	25kV conversion	transformers	60.0	$850	$51,000
	Sinai					
168	2352	3ph 1/0 ACSR	3ph 336 ACSR	0.6	$70,000	$42,000
169	2324	1ph 8A CWC	Vph 1/0 ACSR	2.0	$40,000	$80,000
170	2391	1ph 8A CWC	1 ph #2 ACSR	1.9	$25,000	$47,500
All 1 ph taps from XFMR 2395		25kV conversion	1 ph re-insulation	14.9	$4,500	$67,050
	2394, 2377 to all ends	25kV conversion	transformers	352.0	$850	$299,200
	Load of 2395	Add (3) 1000kVA	Step transformers	3.0	$15,000	$45,000
	Vanarsdell					
171	2272, 2262	3ph 3/0 ACSR	3ph DCT 336ACR	1.4	$85,000	$119,000
172	2271	1ph#4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
173	2256	1ph#4ACSR	3ph 1/0 ACSR	1.4	$55,000	$77,000
	Clay Lick					
174	2160, 2159	3ph 1/0 ACSR	3ph 336 ACSR	2.5	$70,000	$175,000
175	2136	1ph#4ACSR	3ph 1/0 ACSR	1.1	$55,000	$60,500
176	2398	3ph 1/0 ACSR	3ph 336 ACSR	0.6	$70,000	$42,000
177	2471	1ph#4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
	Vanarsdell 2					
178	2228	1 ph #4ACSR	V ph #2 ACSR	1.5	$40,000	$60,000
	2237, 2236, 2234	25kV conversion	3 ph re-insulation	4.1	$13,500	$55,350
	2235	25kV conversion	1 ph re-insulation	2.0	$4,500	$9,000
	2237-2234, 2235	25kV conversion	transformers	59.0	$850	$50,150
	Load of 2234	Add (3) 1000kVA	Step transformers	3.0	$15,000	$45,000

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Powell Taylor 2					
179	2110	1ph#4ACSR	3ph 1/0 ACSR	2.0	$55,000	$110,000
180	2096	1ph#4ACSR	3ph 1/0 ACSR	2.0	$55,000	$110,000
	2094	25kV conversion	transformers	38	$850	$32,300
	Split Bus	69-25/14.4 kV	Add 11.2 MVA			$350,000
	Transmission tap at sub site					$36,000
	Ebenezer					
181	2186	3 ph 1/0 ACSR	3ph DCT 336ACR	0.6	$85,000	$51,000
182	2465	1 ph #4ACSR	V ph #2 ACSR	3.5	$40,000	$140,000
183	2467	1ph#4ACSR	3ph 1/0 ACSR	2.6	$55,000	$143,000
184	2187	3 ph 3/0 ACSR	3ph 336 ACSR	2.8	$70,000	$196,000
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	0.2	$184,000	$36,800
	Transmission tap at sub site					$36,000
HARRISON						
	Cynthiana					
185	4268	1 ph #4ACSR	3ph 1/0 ACSR	1.3	$55,000	$71,500
	Headquarters					
186	4457	1 ph 8A CWC	3ph 1/0 ACSR	1.0	$55,000	$55,000
	Lees Lick					
187	4709, 4519	3 ph DCT 3/0 ACSR	3ph DCT 336ACR	0.8	$85,000	$68,000
188	4518	3 ph 3/0 ACSR	3ph 336 ACSR	1.4	$70,000	$98,000
189	4677, 4678, 4679	3ph 1/0 ACSR	3ph 336 ACSR	1.5	$70,000	$105,000
190	4551	1 ph #4ACSR	3ph 336 ACSR	0.5	$70,000	$35,000
191	4505	1 ph #4ACSR	V ph #2 ACSR	1.3	$40,000	$52,000
192	4660	1 ph #4ACSR	V ph #2 ACSR	0.5	$40,000	$20,000
	Colemansville					
193	4190, 4187, 4185	3 ph 3/0 ACSR	3ph 336 ACSR	2.4	$70,000	$168,000
194	4178	1ph#4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
195	4204	1 ph #4ACSR	V ph #2 ACSR	1.3	$40,000	$52,000
196	4765	1ph#4ACSR	3ph 1/0 ACSR	0.6	$55,000	$33,000
197	4193	1ph#4ACSR	V ph #2 ACSR	0.7	$40,000	$28,000
	Four Oaks					
198	4769, 4143	1ph#4ACSR	3ph 1/0 ACSR	2.5	$55,000	$137,500
199	4147	1ph#4ACSR	3ph 1/0 ACSR	1.3	$55,000	$71,500
200	4069	1ph#4ACSR	V ph #2 ACSR	1.1	$40,000	$44,000
201	4080, 4079	1 ph 8A CWC	3ph 1/0 ACSR	1.6	$55,000	$88,000

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Berlin					
202	4046	3ph 1/0 ACSR	3ph 336 ACSR	1.1	$70,000	$77,000
203	4055	1ph#4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
204	4043	1ph#4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
	Millersburg					
205	4383	1 ph #4ACSR	V ph #2 ACSR	0.5	$40,000	$20,000
206	4421	1 ph #4ACSR	3ph 336 ACSR	2.3	$70,000	$161,000
207	4398	1ph#4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
208	4396	1ph#2ACSR	3ph 1/0 ACSR	0.4	$55,000	$22,000
209	4397	1ph#2ACSR	3ph 1/0 ACSR	0.5	$55,000	$27,500
210	4402	1ph#2ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
	Jacksonville					
211	4535	3ph 3/0 ACSR	3ph 336 ACSR	0.9	$70,000	$63,000
	Oxford					
212	4599, 4605-4607	3ph 1/0 ACSR	3ph 336 ACSR	3.0	$70,000	$210,000
213	4603	1 ph 8A CWC	3ph 1/0 ACSR	0.5	$55,000	$27,500
214	4600	1ph#4ACSR	3ph 1/0 ACSR	1.3	$55,000	$71,500
215	4610	1ph#4ACSR	3ph 1/0 ACSR	1.1	$55,000	$60,500
216	4583	1ph#4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
	Upgrade Substation	20MVA	Transformer	1		$250,000
	West Cynthiana					
217	4688	1 ph #4ACSR	3ph 336 ACSR	1.5	$70,000	$105,000
		69-12.47/7.2kV	20MVA			$570,000
		69kV	Transmission	1.0	$184,000	$184,000
	Transmission tap at sub site					$36,000
	Ruddles Mills					
218	4300, 4444, 4445	3 ph 3/0 ACSR	3ph DCT 336ACR	2.4	$85,000	$204,000
219	4297, 4544	1ph#4ACSR	3ph 336 ACSR	2.0	$70,000	$140,000
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	2.0	$184,000	$368,000
	Transmission tap at sub site					$36,000
NICHOLASVILLE & MADISON						
	Nicholasville					
220	86	1 ph #4ACSR	3ph 336 ACSR	1.3	$70,000	$91,000
	Holloway					
221	8, 15, OH1469	1ph#4ACSR	3ph 1/0 ACSR	1.9	$55,000	$104,500

Code	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Davis					
	Add fans					$8,000
	Newby					
222	556 Xpress		3 ph 556 ACSR	3.6	$85,000	$306,000
223	192	1ph#4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
224	198	1 ph 6A CWC	3ph 1/0 ACSR	2.5	$55,000	$137,500
225	202	1ph#4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
	West Berea					
226	420	1ph#4ACSR	3ph 1/0 ACSR	0.4	$55,000	$22,000
	South Elkhorn					
227	501	1ph#4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
228	403	3ph 336 ACSR	3ph DCT 336ACR	1.5	$85,000	$127,500
	Upgrade Substation	20MVA	Transformer	1		$250,000
	Crooksville					
229	263, 294, 257	3ph 1/0 ACSR	3ph DCT 336ACR	4.1	$85,000	$348,500
	Upgrade Substation	20MVA	Transformer	1		$250,000
	South Jessamine					
230	428	1 ph #4ACSR	V ph #2 ACSR	1.3	$40,000	$52,000
231	124	1 ph #4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
232	350	1 ph #4ACSR	3ph 1/0 ACSR	2.8	$55,000	$154,000
	North Madison					
233	178	3ph 1/0 ACSR	3ph 336 ACSR	0.4	$70,000	$28,000
234	177	1 ph #4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
	West Berea 2					
235	324	1ph#4ACSR	3ph 1/0 ACSR	2.1	$55,000	$115,500
236	330	1ph#4ACSR	3ph 1/0 ACSR	2.3	$55,000	$126,500
	West Nicholasville 2					
237	152	1ph#4ACSR	3ph 1/0 ACSR	1.7	$55,000	$93,500
	Boone Gap					
	(Jackson Energy)					
238	416	3ph 1/0 ACSR	3ph 336 ACSR	1.7	$70,000	$119,000
	North Nicholasville					
239	4 UG feeder getaways		500MCM UG	0.5	$238,000	$119,000
		69-12.47/7.2kV	20MVA			$570,000
		69kV	Transmission	1	$184,000	$184,000
	Transmission tap at sub site					$36,000

ALTERNATE PLAN
LOAD LEVEL A (2004-2005)
2004 DOLLARS

Sub/Section		From	To	Miles/Units	Unit Cost	Total Costs
FOX CREEK						
	Bridgeport					
	2035, 2442	1 ph 8A CWC	1 ph #2 ACSR	2.6	$25,000	$65,000
	2035, 2442	25kV conversion	transformers	20.0	$850	$17,000
	Load of 2105	Add 300 kVAR	3 ph Capacitor	1.0	$3,500	$3,500
	Ninevah					
	2437-2433, 2061, 2430	3 ph DCT #2 ACSR	3 ph DCT 336 ACSR	2.1	$85,000	$178,500
	2427-2297	3 ph #2 ACSR	3 ph 336.4 ACSR	5.7	$70,000	$399,000
	2057	1 ph #4 ACSR	1 ph #2 ACSR	5.5	$25,000	$137,500
	2057	25kV conversion	transformers	53.0	$850	$45,050
	Source of 2057	Add (1) 500 kVA	Step transformers	1.0	$9,200	$9,200
	Load of 2297	Add (3) 150A	Voltage Regulator	1.0	$32,100	$32,100
	Sinai					
	2511-2395	3 ph #4 ACSR	3 ph 336.4 ACSR	4.2	$70,000	$294,000
	2394-2429	3 ph #4 ACSR	3 ph 1/0 ACSR	4.3	$55,000	$236,500
	2389	1 ph 8A CWC	3 ph 1/0 ACSR	1.5	$55,000	$82,500
	2367-2345	1 ph #4 ACSR	3 ph 1/0 ACSR	4.4	$55,000	$242,000
	2302	1 ph 8A CWC	3 ph 1/0 ACSR	0.6	$55,000	$33,000
	2462	1 ph 8A CWC	3 ph 1/0 ACSR	2.3	$55,000	$126,500
	2326	1 ph 8A CWC	V ph 1/0 ACSR	2.3	$55,000	$126,500
	Vanarsdell					
	2176	1 ph 1/0 ACSR	3 ph 1/0 ACSR	2.9	$55,000	$159,500
	2214, 2212	1 ph #4 ACSR	3 ph 1/0 ACSR	5.2	$55,000	$286,000
	Source of 2186	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	Source of 2187	Add (3) 150A	Voltage Regulator	1.0	$32,100	$32,100
	Source of 2239	Add (2) 100A	Voltage Regulator	1.0	$20,000	$20,000
	Source of 2265	Add (3) 100A	Voltage Regulator	1.0	$30,000	$30,000
	Load of 2457	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Clay Lick					
	2142	1 ph #4 ACSR	3 ph 1/0 ACSR	1.2	$55,000	$66,000
	2155A	1 ph 8A CWC	3 ph 1/0 ACSR	3.5	$55,000	$192,500
	2119	1 ph 8A CWC	3 ph 1/0 ACSR	2.5	$55,000	$137,500
	2147	1 ph 8A CWC	V ph #2 ACSR	1.8	$40,000	$72,000
	Source of 2159	Add (3) 150A	Voltage Regulator	1.0	$32,100	$32,100
	Source of 2137	Add (3) 100A	Voltage Regulator	1.0	$30,000	$30,000
	Source of 2126	Add (3) 100A	Voltage Regulator	1.0	$30,000	$30,000
	Load of 2151	Add 300 kVAR	3 ph Capacitor	1.0	$3,500	$3,500
	Sinai 2					
	2296, 2293	3 ph #4 ACSR	3 ph 336.4 ACSR	2.0	$70,000	$140,000
	2094	1 ph 8A CWC	1 ph #2 ACSR	3.0	$25,000	$75,000
	2323-2301	25 kV conversion	3 ph re-insulation	20.0	$13,500	$270,000
	2294-95, 2093 to open	25 kV conversion	1 ph re-insulation	4.0	$4,500	$18,000
		25 kV conversion	transformers	486	$850	$413,100
	Source of 2313	Add (3) 1000kVA	Step transformers	3	$12,000	$36,000
	Split Bus	69-25/14.4kV	20 MVA			$375,000
	Transmission tap at sub site					$36,000
HARRISON						
	Cynthiana					
	4315	1 ph #4 ACSR	3 ph 1/0 ACSR	0.5	$55,000	$27,500
	4693	1 ph 1/0 URD	1 ph 1/0 URD	1.3	$75,000	$97,500
	Load of 4299	Add 600 kVAR	3 ph Capacitor	1.0	$4,500	$4,500
	Headquarters					
	4345-4337	3 ph #4 ACSR	3 ph 336.4 ACSR	4.9	$70,000	$343,000
	Upgrade Substation	11.2MVA	Transformer	1		$200,000
	Lees Lick					
	4504-4748	1 ph 8A CWC	3 ph 1/0 ACSR	2.7	$55,000	$148,500
	4661	1 ph #4 ACSR	3 ph 1/0 ACSR	0.4	$55,000	$22,000
	4592	1 ph #4 ACSR	3 ph 1/0 ACSR	0.1	$55,000	$5,500
	4499	1 ph 8A CWC	3 ph 1/0 ACSR	0.5	$55,000	$27,500
	Source of 4675	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	Colemansville					
	4161	1 ph #4 ACSR	3 ph 1/0 ACSR	0.9	$55,000	$49,500
	4241	1 ph 8A CWC	V ph #2 ACSR	0.8	$40,000	$32,000
	4250, 4249	1 ph 8A CWC	3 ph 1/0 ACSR	1.0	$55,000	$55,000
	Source of 4178	Add (1) 50A	Voltage Regulator	1.0	$9,000	$9,000

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Four Oaks					
	H4131, 4743, 4130	1 ph 8A CWC	3 ph 1/0 ACSR	0.8	$55,000	$44,000
	Berlin					
	4784, 4007	1 ph #4 ACSR	3 ph 1/0 ACSR	1.9	$55,000	$104,500
	4014	1 ph 8A CWC	V ph #2 ACSR	0.8	$40,000	$32,000
	4037	1 ph 8A CWC	V ph #2 ACSR	0.5	$40,000	$20,000
	4016	1 ph #4 ACSR	3 ph 1/0 ACSR	0.7	$55,000	$38,500
	4015	3 ph #4 ACSR	3 ph 336.4 ACSR	1.0	$70,000	$70,000
	Upgrade Substation	11.2MVA	Transformer	1		$200,000
	Millersburg					
	4418, 4991, 4416	1 ph #2 ACSR	3 ph 1/0 ACSR	0.8	$55,000	$44,000
	4403	1 ph #2 ACSR	3 ph 1/0 ACSR	0.7	$55,000	$38,500
	Jacksonville					
	Load of 4532	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	Lees Lick 2					
	4627,4626	3 ph 336.4 ACSR	3 ph DCT 336.4	1.4	$85,000	$119,000
	4638, 4650	1 ph 8A CWC	3 ph 1/0 ACSR	1.3	$55,000	$71,500
	4594-end	25 kV conversion	3 ph re-insulation	7.6	$13,500	$102,600
			1 ph re-insulation	11.9	$4,500	$53,550
		25 kV conversion	transformers	546	$850	$464,100
	4625-end	25 kV conversion	3 ph re-insulation	9.0	$13,500	$121,500
			1 ph re-insulation	5.3	$4,500	$23,850
		25 kV conversion	transformers	648	$850	$550,800
	Split Bus	69-25/14.4kV	20 MVA			$375,000
	Transmission tap at sub site					$36,000
NICHOLASVILLE & MADISON						
	Nicholasville					
	171 ext		3 ph 336.4 ACSR	0.2	$70,000	$14,000
	Holloway					
	20	1 ph #4 ACSR	3 ph 1/0 ACSR	2.5	$55,000	$137,500
	406	1 ph 1/0 URD	1 ph 1/0 URD	1.2	$75,000	$90,000
	487	1 ph 1/0 URD	1 ph 1/0 URD	0.8	$75,000	$60,000
	West Nicholasville					
	New Getaway		3 ph 500 MCM UG	0.1	$238,000	$23,800
	New Feeder		3 ph 336.4 ACSR	0.4	$70,000	$28,000
	430		3 ph 336.4 ACSR	0.9	$70,000	$63,000

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Fayette One					
	All Getaways	3 ph 4/0 URD	3 ph 500 MCM UG	0.4	$238,000	$95,200
	456, 478	1 ph 1/0 URD	1 ph 1/0 URD	0.9	$75,000	$67,500
	453	1 ph 1/0 URD	1 ph 1/0 URD	0.4	$75,000	$30,000
	460	1 ph 1/0 URD	1 ph 1/0 URD	0.6	$75,000	$45,000
	454	1 ph 1/0 URD	1 ph 1/0 URD	0.6	$75,000	$45,000
	445	1 ph 1/0 URD	1 ph 1/0 URD	0.2	$75,000	$15,000
	Fayette Two					
	477, 479, 504	1 ph 1/0 URD	1 ph 1/0 URD	1.3	$75,000	$97,500
	Newby					
	216, 232	1 ph #4 ACSR	3 ph 1/0 ACSR	1.0	$55,000	$55,000
	Source of 229	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	Hickory Plains					
	303, 302	1 ph #4 ACSR	3 ph 336.4 ACSR	1.9	$70,000	$133,000
	287A, 287	1 ph #4 ACSR	3 ph 1/0 ACSR	0.8	$55,000	$44,000
	285A-389	3 ph 4/0 ACSR	3 ph 336.4 ACSR	2.5	$70,000	$175,000
	415	1 ph 6A CWC	3 ph 1/0 ACSR	0.5	$55,000	$27,500
	307, 310	1 ph #4 ACSR	3 ph 1/0 ACSR	2.1	$55,000	$115,500
	South Elkhorn					
	510	1 ph 1/0 URD	1 ph 1/0 URD	0.4	$75,000	$30,000
	Upgrade Substation	20MVA	Transformer	1		$250,000
	Crooksville					
	251	1 ph #4 ACSR	3 ph 1/0 ACSR	0.4	$55,000	$22,000
	297	1 ph #4 ACSR	3 ph 1/0 ACSR	2.2	$55,000	$121,000
	440	1 ph #4 ACSR	3 ph 1/0 ACSR	0.3	$55,000	$16,500
	Source of 249	Add (1) 50A	Voltage Regulator	1.0	$9,000	$9,000
	South Jessamine					
	104	1 ph #4 ACSR	3 ph 1/0 ACSR	0.9	$55,000	$49,500
	556 xpress		3 ph 556 ACSR	0.4	$85,000	$34,000
	156	1 ph 6A CWC	V ph 1/0 ACSR	1.5	$47,000	$70,500
	North Madison					
	174	3 ph 1/0 ACSR	3 ph DCT 336 ACSR	2.0	$85,000	$170,000
	173	1 ph #4 ACSR	3 ph 336.4 ACSR	1.3	$70,000	$91,000
	188	1 ph #4 ACSR	3 ph 1/0 ACSR	1.1	$55,000	$60,500
	Davis 2					
	404-408	3 ph 336.4 ACSR	3 ph DCT 556	6.1	$95,000	$579,500
	Split Bus	69-25/14.4kV	11.2 MVA			$350,000
	Transmission tap at sub site					$36,000

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	West Berea 2					
	Split Bus	69-25/14.4 kV	Add 11.2 MVA			$350,000
	Transmission tap at sub site					$36,000

**ALTERNATE
PLAN
LOAD LEVEL B (2006-2009)
2004 DOLLARS**

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
FOX CREEK						
	Bridgeport					
	2052	1ph 8A CWC	3ph 1/0 ACSR	3.3	$55,000	$181,500
	2020, 2021, 2018, 2030, 2029, 2027,	3ph #4ACSR	3ph 1/0 ACSR	7.3	$55,000	$401,500
	2434	1ph#4ACSR	3ph 1/0 ACSR	1	$55,000	$55,000
	2043	1ph 8A CWC	1 ph #2 ACSR	1.8	$25,000	$45,000
	2023, 2440, 2478	1 ph 8A CWC	1 ph #2 ACSR	3.5	$25,000	$87,500
	2082	1 ph #4 ACSR	3 ph 1/0 ACSR	2.1	$55,000	$115,500
	2085	1 ph #4 ACSR	3 ph 336.4 ACSR	2.3	$70,000	$161,000
	Ninevah					
	2079, 2080, 2475	3ph #4ACSR	3ph 336 ACSR	2.5	$70,000	$175,000
	2074, 2076	3ph #4ACSR	3ph 1/0 ACSR	4.8	$55,000	$264,000
	Sinai					
	2091	1ph 8A CWC	3ph 1/0 ACSR	2.0	$55,000	$110,000
	2273	1ph#4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
	2304	1ph 8A CWC	3ph 1/0 ACSR	1.8	$55,000	$99,000
	2327	1ph 8A CWC	3ph 1/0 ACSR	2.3	$55,000	$126,500
	2331	1ph 8A CWC	3ph 1/0 ACSR	1.4	$55,000	$77,000
	2408, 2409	1ph 8A CWC	3ph 1/0 ACSR	1.9	$55,000	$104,500
	2377	1ph#4ACSR	3ph 1/0 ACSR	0.5	$55,000	$27,500
	2280, 2279	1ph 8A CWC	1 ph #2 ACSR	1.9	$25,000	$47,500
	2365-2363	1ph 8A CWC	3ph 1/0 ACSR	2.5	$55,000	$137,500
	2385-2388	1 ph 8A CWC	1 ph #2 ACSR	6.0	$25,000	$150,000
	Load of 2417	Add (3) 219A	Voltage Regulator	1	$37,500	$37,500
	Vanarsdell					
	2230	1 ph #4 ACSR	V ph #2 ACSR	1.6	$40,000	$64,000
	Load of 2270	Add (3) 150A	Voltage Regulator	1	$32,100	$32,100

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Clay Lick					
	2157	3ph 1/0 ACSR	3ph TRP CKT 336	0.9	$85,000	$76,500
	2158	1ph#4ACSR	3ph 336 ACSR	2.5	$70,000	$175,000
	2506	1ph 8A CWC	1 ph #2 ACSR	0.5	$25,000	$12,500
	2400,2139	1ph#4ACSR	3ph 1/0 ACSR	2.2	$55,000	$121,000
	2121	1ph#4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
	2464, 2447, 2448	1ph#2ACSR	3ph 1/0 ACSR	2.6	$55,000	$143,000
	2133	1 ph #4 ACSR	3 ph 1/0 ACSR	2.7	$55,000	$148,500
	2155B	1 ph 8A CWC	1 ph #2 ACSR	2.9	$25,000	$72,500
	2149, 2146, 2145, 2144	1 ph 8A CWC	1 ph #2 ACSR	5.2	$25,000	$130,000
	Sinai 2					
	2295, 2294	1 ph 8A CWC	3 ph 1/0 ACSR	2.5	$55,000	$12,500
	2093	1 ph 8A CWC	3 ph 1/0 ACSR	0.4	$55,000	$22,000
	2099, 2092	1 ph 8A CWC	1 ph #2 ACSR	1.3	$25,000	$32,500
	South Benson					
	2105	3 ph 3/0 ACSR	3ph DCT 336ACR	0.7	$85,000	$59,500
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	2.5	$184,000	$460,000
	Transmission tap at sub site					$36,000
	Bohon					
	2219	1 ph #4ACSR	3ph 1/0 ACSR	1.1	$55,000	$60,500
	2480, 2206	1 ph #4ACSR	3ph 1/0 ACSR	2.9	$55,000	$159,500
	2199	1ph#4ACSR	3 ph #2 ACSR	6.2	$47,000	$291,400
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	6.6	$184,000	$1,214,400
	Transmission tap at sub site					$36,000
HARRISON						
	Cynthiana					
	4547	1 ph #4ACSR	3ph 336 ACSR	0.5	$70,000	$35,000
	4292, 4293	3 ph 3/0 ACSR	3ph DCT 336ACR	0.5	$85,000	$42,500
	4327	1ph#4ACSR	3ph 336 ACSR	0.9	$70,000	$63,000
	Headquarters					
	4371, 4369	1 ph #4ACSR	V ph #2 ACSR	1.2	$40,000	$48,000
	4431, 4432	1 ph #4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
	4488	1 ph #4ACSR	3ph 1/0 ACSR	2.1	$55,000	$115,500
	Lees Lick					
	4586, 4587, 4588	1 ph #4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
	4678, 4679	3ph 1/0 ACSR	3ph 336 ACSR	0.9	$70,000	$63,000

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Colemansville					
	4156, 4780	1 ph #4ACSR	V ph #2 ACSR	2.4	$40,000	$96,000
	4189	1 ph #2ACSR	3ph 1/0 ACSR	2.3	$55,000	$126,500
	4201,4756	1 ph #4ACSR	V ph #2 ACSR	0.6	$40,000	$24,000
	4249	3ph 8A CWC	3ph 1/0 ACSR	0.5	$55,000	$27,500
	4159	1 ph #4 ACSR	V ph #2 ACSR	1.5	$40,000	$60,000
	Load of 4179	Add (3) 100A	Voltage Regulator	1	$30,000	$30,000
	Four Oaks					
	4077, 4075, 4074	1ph 8A CWC	3ph 336 ACSR	1.8	$70,000	$126,000
	4151, 4149	1ph 8A CWC	3ph 1/0 ACSR	2.6	$55,000	$143,000
	4150	1ph 8A CWC	1 ph #2 ACSR	1.8	$25,000	$45,000
	4089, 4772, 4086-4088	1 ph #4 ACSR	1 ph #2 ACSR	3.6	$25,000	$90,000
	Berlin					
	4011, 4009, 4006, 4004, 4002	3ph #4ACSR	3ph 336 ACSR	3.8	$70,000	$266,000
	Millersburg					
	4423, 4424	1 ph #4ACSR	3ph 336 ACSR	1.0	$70,000	$70,000
	Jacksonville					
	4568	1 ph #4ACSR	3ph 336 ACSR	1.0	$70,000	$70,000
	Lees Lick 2					
	4594, 4593, 4751, 4622, 4623	3ph 1/0 ACSR	3ph 336 ACSR	2.9	$70,000	$203,000
	4752, 4595	1ph 8A CWC	1ph #2 ACSR	1.2	$25,000	$30,000
	4621	1 ph #4 ACSR	3 ph 1/0 ACSR	1.8	$55,000	$99,000
NICHOLASVILLE & MADISON						
	Nicholasville					
	59	1 ph #4ACSR	3ph 1/0 ACSR	1.7	$55,000	$93,500
	Holloway					
	21	3 ph #4ACSR	3ph 336 ACSR	0.9	$55,000	$49,500
	3	1 ph #4ACSR	3ph 1/0 ACSR	1.1	$55,000	$60,500
	Source of 17	Add (1)50A	Voltage Regulator	1	$9,000	$9,000
	West Nicholasville					
	25	1 ph #4ACSR	Vph 1/0 ACSR	1.1	$47,000	$51,700
	150	1 ph #4ACSR	V ph #2 ACSR	0.9	$40,000	$36,000
	154	1 ph #4ACSR	Vph 1/0 ACSR	0.6	$47,000	$28,200

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Davis					
	42	1 ph #4ACSR	3ph 1/0 ACSR	1.7	$55,000	$93,500
	Newby					
	205	3 ph 1/0 ACSR	3ph 336 ACSR	0.9	$70,000	$63,000
	247	1 ph 6A CWC	3 ph 1/0 ACSR	3.0	$55,000	$165,000
	West Berea					
	332	1 ph #4ACSR	3ph 1/0 ACSR	1.7	$55,000	$93,500
	240	1 ph #4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
	Hickory Plains					
	305	1 ph #4ACSR	3ph 336 ACSR	2.7	$70,000	$189,000
	309	1 ph #4ACSR	3ph 336 ACSR	1.3	$70,000	$91,000
	287	3 ph #4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
	South Elkhorn					
	1	1 ph #4ACSR	3ph 1/0 ACSR	1.3	$55,000	$71,500
	407, 1	1 ph #4 ACSR	3 ph 1/0 ACSR	1.5	$55,000	$82,500
	Upgrade Substation	25MVA	Transformer	1		$350,000
	Crooksville					
	249	1 ph #4ACSR	3ph 1/0 ACSR	2.0	$55,000	$110,000
	254	1 ph #4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
	299	1 ph #4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
	365	1 ph #4ACSR	V ph #2 ACSR	1.3	$40,000	$52,000
	292	1 ph #4ACSR	3ph 1/0 ACSR	2.8	$55,000	$154,000
	Load of 294	Add (3) 219A	Voltage Regulator	1.0	$37,500	$37,500
	South Jessamine					
	OH 422, 141, 138	3 ph 4/0 ACSR	3ph DCT 336ACR	1.9	$85,000	$161,500
	OH 571, 126	1 ph #4ACSR	3ph 1/0 ACSR	2.4	$55,000	$132,000
	145 Extended		3ph 336 ACSR	0.4	$70,000	$28,000
	157	1 ph 6A CWC	V ph 1/0 ACSR	1.5	$47,000	$70,500
	101	1 ph 1/0 ACSR	V ph 1/0 ACSR	1.3	$47,000	$61,100
	North Madison					
	186	1 ph #4ACSR	3ph 1/0 ACSR	1.4	$55,000	$77,000
	172	3 ph 1/0 ACSR	3ph 336 ACSR	2.3	$70,000	$161,000
	184	3 ph #4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
	West Berea 2					
	321	1 ph 1/0 ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
West Nicholasville 2						
	Split Bus	69-12.47/7.2kV	20 MVA			$375,000
	Transmission tap at sub site					$36,000

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Kirksville					
	220	3 ph 1/0 ACSR	3ph DCT 336ACR	0.1	$85,000	$8,500
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	3.6	$184,000	$662,400
	Transmission tap at sub site					$36,000
	Duncanon					
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	1.5	$184,000	$276,000
	Transmission tap at sub site					$36,000
	Hickory Plains 2					
	447, 308, 285, 284	3ph 336 ACSR	3ph DCT 556ACR	4.5	$95,000	$427,500
	279	3 ph #4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
	Split Bus	69-12.47/7.2kV	20 MVA			$375,000
	Transmission tap at sub site					$36,000

ALTERNATE
PLAN
LOAD LEVEL C (2010-2014)
2004 DOLLARS

Sub/Section		From	To	Miles/Units	Unit Cost	Total Costs
FOX CREEK						
	Bridgeport					
	2002	1ph 1/0 ACSR	3ph 1/0 ACSR	2.3	$55,000	$126,500
	2113	1ph 8A CWC	3ph 1/0 ACSR	1.9	$55,000	$104,500
	2024	1ph#4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
	2031, 2441, 2026	1ph 8A CWC	1 ph #2 ACSR	3.8	$25,000	$95,000
	2031, 2441, 2026	25kV conversion	transformers	60.0	$850	$51,000
	Ninevah					
	2472	1ph#4ACSR	3ph 1/0 ACSR	0.5	$55,000	$27,500
	Sinai					
	2352	3ph 1/0 ACSR	3ph 336 ACSR	0.6	$70,000	$42,000
	2324	1ph 8A CWC	Vph 1/0 ACSR	2.0	$40,000	$80,000
	2391	1ph 8A CWC	1 ph #2 ACSR	1.9	$25,000	$47,500
All 1 ph taps from XFMR 2395		25kV conversion	1 ph re-insulation	14.9	$4,500	$67,050
	2394, 2377 to all ends	25kV conversion	transformers	352.0	$850	$299,200
	Load of 2395	Add (3) 100kVA	Step transformers	3.0	$15,000	$45,000
	Vanarsdell					
	2271	1ph#4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
	2262, 2272	3 ph 3/0 ACSR	3 ph 556 ACSR	1.4	$85,000	$119,000
	2256	1ph#4ACSR	3ph 1/0 ACSR	1.4	$55,000	$77,000
	Clay Lick					
	2160, 2159	3ph 1/0 ACSR	3ph 336 ACSR	2.5	$70,000	$175,000
	2136	1ph#4ACSR	3ph 1/0 ACSR	1.1	$55,000	$60,500
	2398	3ph 1/0 ACSR	3ph 336 ACSR	0.6	$70,000	$42,000
	2471	1ph#4ACSR	3ph 1/0 ACSR	1.6	$55,000	$88,000
	South Benson					
	2110	1ph#4ACSR	3ph 1/0 ACSR	2.0	$55,000	$110,000
	2096	1ph#4ACSR	3ph 1/0 ACSR	2.0	$55,000	$110,000
	Bohon					
	2228	1 ph #4ACSR	V ph #2 ACSR	1.5	$40,000	$60,000

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Ebenezer					
	2186	3 ph 1/0 ACSR	3ph DCT 336ACR	0.6	$85,000	$51,000
	2465	1 ph #4ACSR	V ph #2 ACSR	3.5	$40,000	$140,000
	2467	1ph#4ACSR	3ph 1/0 ACSR	2.6	$55,000	$143,000
	2187	3 ph 3/0 ACSR	3ph 336 ACSR	2.8	$70,000	$196,000
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	0.2	$184,000	$36,800
	Transmission tap at sub site					$36,000
HARRISON						
	Cynthiana					
	4688	1 ph #4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
	4268	1 ph #4ACSR	3ph 1/0 ACSR	1.3	$55,000	$71,500
	Headquarters					
	4457	1 ph 8A CWC	3ph 1/0 ACSR	1.0	$55,000	$55,000
	Lees Lick					
	4709, 4519	3 ph DCT 3/0 ACSR	3ph DCT 336ACR	0.8	$85,000	$68,000
	4518	3 ph 3/0 ACSR	3ph 336 ACSR	1.4	$70,000	$98,000
	4551	1 ph #4ACSR	3ph 336 ACSR	0.5	$70,000	$35,000
	4505	1 ph #4ACSR	V ph #2 ACSR	1.3	$40,000	$52,000
	4660	1 ph #4ACSR	V ph #2 ACSR	0.5	$40,000	$20,000
	Colemansville					
	4190, 4187, 4185	3 ph 3/0 ACSR	3ph 336 ACSR	2.4	$70,000	$168,000
	4178	1ph#4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
	4204	1 ph #4ACSR	V ph #2 ACSR	1.3	$40,000	$52,000
	4765	1ph#4ACSR	3ph 1/0 ACSR	0.6	$55,000	$33,000
	4193	1ph#4ACSR	V ph #2 ACSR	0.7	$40,000	$28,000
	Four Oaks					
	4769, 4143	1ph#4ACSR	3ph 1/0 ACSR	2.5	$55,000	$137,500
	4147	1ph#4ACSR	3ph 1/0 ACSR	1.3	$55,000	$71,500
	4069	1ph#4ACSR	V ph #2 ACSR	1.1	$40,000	$44,000
	4080, 4079	1 ph 8A CWC	3ph 1/0 ACSR	1.6	$55,000	$88,000
	Berlin					
	4027, 4025	V ph #4 ACSR	3ph 336 ACSR	3.8	$70,000	$266,000
	4055	1ph#4ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000
	4043	1ph#4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
	Millersburg					
	4383	1 ph #4ACSR	V ph #2 ACSR	0.5	$40,000	$20,000
	4421	1 ph #4ACSR	3ph 336 ACSR	2.3	$70,000	$161,000
	4398	1ph#4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
	4396	1ph#2ACSR	3ph 1/0 ACSR	0.4	$55,000	$22,000
	4397	1ph#2ACSR	3ph 1/0 ACSR	0.5	$55,000	$27,500
	4402	1ph#2ACSR	3ph 1/0 ACSR	0.8	$55,000	$44,000

	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	Jacksonville					
	4535	3ph 3/0 ACSR	3ph 336 ACSR	0.9	$70,000	$63,000
	Lees Lick 2					
	4620, 4618, 4616, 4614, 4612	3ph 1/0 ACSR	3ph 336 ACSR	3.1	$70,000	$217,000
	Cynthiana 2					
	4329, 4735, 4545	3 ph DCT 3/0 ACSR	3ph DCT 556ACR	1.6	$95,000	$152,000
	4328	3ph 3/0 ACSR	3ph 556ACSR	1.2	$85,000	$102,000
	Split Bus	69-12.47/7.2kV	20 MVA			$375,000
	Transmission tap at sub site					$36,000
	Ruddles Mills					
	4300, 4444, 4445	3 ph 3/0 ACSR	3ph DCT 336ACR	2.4	$85,000	$204,000
	4297, 4544	1ph#4ACSR	3ph 336 ACSR	2.0	$70,000	$140,000
		69-12.47/7.2kV	11.2MVA			$517,000
		69kV	Transmission	2.0	$184,000	$368,000
	Transmission tap at sub site					$36,000
NICHOLASVILLE & MADISON						
	Nicholasville					
	86	1 ph #4ACSR	3ph 336 ACSR	1.3	$70,000	$91,000
	Holloway					
	8, 15, OH1469	1ph#4ACSR	3ph 1/0 ACSR	1.9	$55,000	$104,500
	Davis					
	Add fans					$8,000
	Newby					
	192	1ph#4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
	198	1 ph 6A CWC	3ph 1/0 ACSR	2.5	$55,000	$137,500
	202	1ph#4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
	West Berea					
	420	1ph#4ACSR	3ph 1/0 ACSR	0.4	$55,000	$22,000
	Hickory Plains					
	306, 304	3ph 4/0 ACSR	3ph DCT 336ACR	2.3	$85,000	$195,500
	South Elkhorn					
	501	1ph#4ACSR	3ph 1/0 ACSR	0.9	$55,000	$49,500
	403	3ph 336 ACSR	3ph DCT 336ACR	1.5	$85,000	$127,500
	Upgrade Substation	20MVA	Transformer	1		$250,000

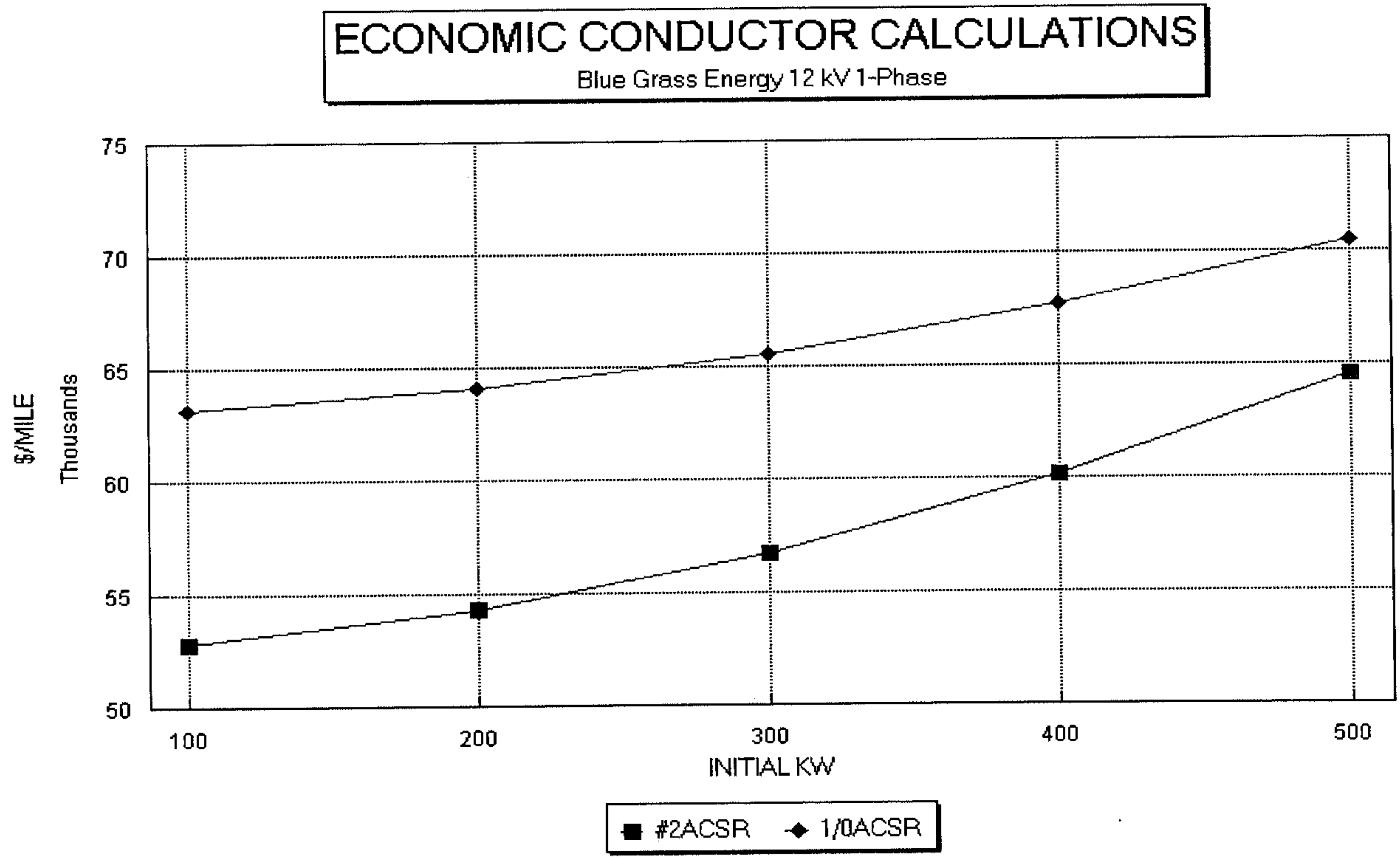
	Sub/Section	From	To	Miles/Units	Unit Cost	Total Costs
	South Jessamine					
	428	1 ph #4ACSR	V ph #2 ACSR	1.3	$40,000	$52,000
	124	1 ph #4ACSR	3ph 1/0 ACSR	1.5	$55,000	$82,500
	350	1 ph #4ACSR	3ph 1/0 ACSR	2.8	$55,000	$154,000
	North Madison					
	178	3ph 1/0 ACSR	3ph 336 ACSR	0.4	$70,000	$28,000
	177	1 ph #4ACSR	3ph 1/0 ACSR	1.0	$55,000	$55,000
	West Berea 2					
	330	1ph#4ACSR	3ph 1/0 ACSR	2.3	$55,000	$126,500
West Nicholasville 2						
	152	1ph#4ACSR	3ph 1/0 ACSR	1.7	$55,000	$93,500
	Kirksville					
	324	1ph#4ACSR	3ph 1/0 ACSR	2.1	$55,000	$115,500
	Hickory Plains 2					
	276, 274, 272	3ph 1/0 ACSR	3ph 336 ACSR	4.3	$70,000	$301,000
	270	1ph#4ACSR	3ph 1/0 ACSR	2.8	$55,000	$154,000
	North Richmond					
		69-12.47/7.2kV	11.2 MVA			$517,000
		69kV	Transmission	1.0	$184,000	$184,000
	Transmission tap at sub site					$36,000
	Boone Gap	---->Jackson Energy				
	416	3ph 1/0 ACSR	3ph 336 ACSR	1.7	$70,000	$119,000
	Bybee					
		69-12.47/7.2kV	11.2 MVA			$517,000
		69kV	Transmission	2.5	$184,000	$460,000
	Transmission tap at sub site					$36,000
	South Point					
		69-12.47/7.2kV	11.2 MVA			$517,000
		69kV	Transmission	0.5	$184,000	$92,000
	Transmission tap at sub site					$36,000
North Nicholasville						
	4 UG feeder getaways		500MCM UG	0.5	$238,000	$119,000
		69-12.47/7.2kV	20MVA			$570,000
		69kV	Transmission	1	$184,000	$184,000
	Transmission tap at sub site					$36,000

Blue Grass Energy Cooperative
12 kV 1-Phase
ECONOMIC CONDUCTOR CALCULATIONS

O&M	TAX	INS	INT	$/KW	$/KWH	KW
4.52%	0.50%	0.37%	5.50%	5.52	0.023	100
RMO	**RAT**	**KWI**	**KWHI**	**LGR**	**INF**	**m**
12	0.0%	2.00%	2.00%	2.00%	2.50%	30
LF	**PF**	**CF**	**N**	**KV**	**P**	
52.0%	94.0%	90.0%	0.52	7.2	1	

CONDUCTOR	2ACSR	1/0ACSR
COST/MI	$25,000	$30,000
OHMS/MI	1.410	0.885
TCOST/MI	$108,807	$130,043
PWCOST/MI	$52,837	$63,126

APPENDIX A



ECONOMIC CONDUCTOR CALCULATIONS
Blue Grass Energy 12 kV 1-Phase
$/MILE
Thousands
75
70
65
60
55
50
100
200
300
400
500
INITIAL KW
#2ACSR
1/0ACSR

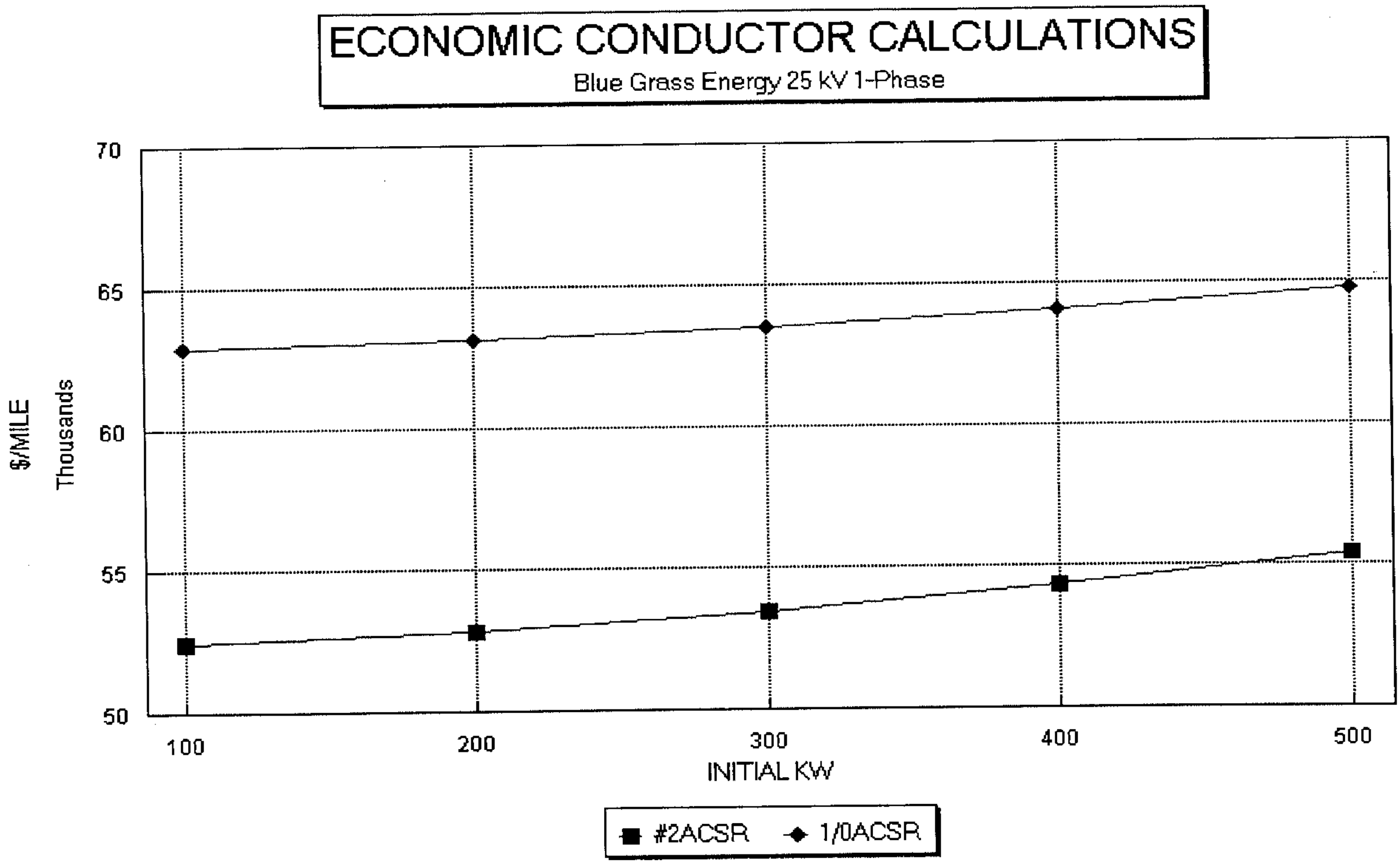
APPENDIX A

Blue Grass Energy Cooperative
25 kV 1-Phase
ECONOMIC CONDUCTOR CALCULATIONS

O&M	TAX	INS	INT	$/KW	$/KWH	KW
4.52%	0.50%	0.37%	5.50%	5.52	0.023	100
RMO	RAT	KWI	KWHI	LGR	INF	m
12	0.0%	2.00%	2.00%	2.00%	2.50%	30
LF	PF	CF	N	KV	P	
52.0%	94.0%	90.0%	0.52	14.4	1	

CONDUCTOR	2ACSR	1/0ACSR
COST/MI	$25,000	$30,000
OHMS/MI	1.410	0.885
TCOST/MI	$108,119	$129,612
PWCOST/MI	$52,472	$62,897

APPENDIX A


ECONOMIC CONDUCTOR CALCULATIONS
Blue Grass Energy 25 kV 1-Phase
$/MILE
Thousands
70
65
60
55
50
100
200
300
400
500
INITIAL KW
#2ACSR
1/0ACSR

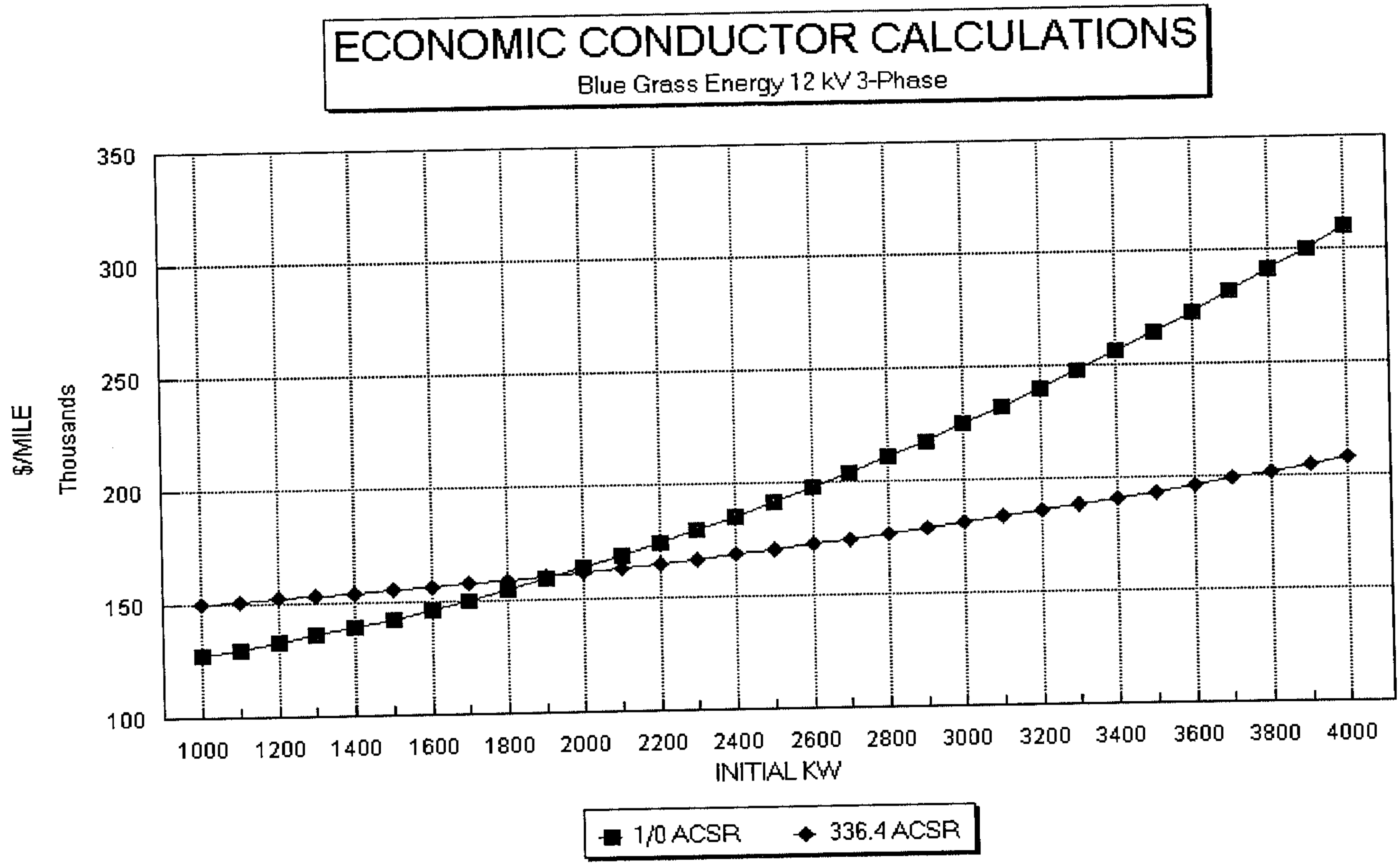
APPENDIX A

Blue Grass Energy Cooperative
12 kV 3-Phase
ECONOMIC CONDUCTOR CALCULATIONS

O&M	TAX	INS	INT	$/KW	$/KWH	KW
4.52%	0.50%	0.37%	5.50%	5.52	0.023	1000
RMO	RAT	KWI	KWHI	LGR	INF	m
12	0.0%	2.00%	2.00%	2.00%	2.50%	30
LF	PF	CF	N	KV	P	
60.0%	94.0%	90.0%	0.52	7.2	3	

CONDUCTOR	1/0 ACSR	336.4 ACSR
COST/MI	$55,000	$70,000
OHMS/MI	0.885	0.278
TCOST/MI	$260,300	$309,299
PWCOST/MI	$127,343	$150,404

APPENDIX A


ECONOMIC CONDUCTOR CALCULATIONS
Blue Grass Energy 12 kV 3-Phase
$/MILE
Thousands
350
300
250
200
150
100
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
3200
3400
3600
3800
4000
INITIAL KW
1/0 ACSR
336.4 ACSR

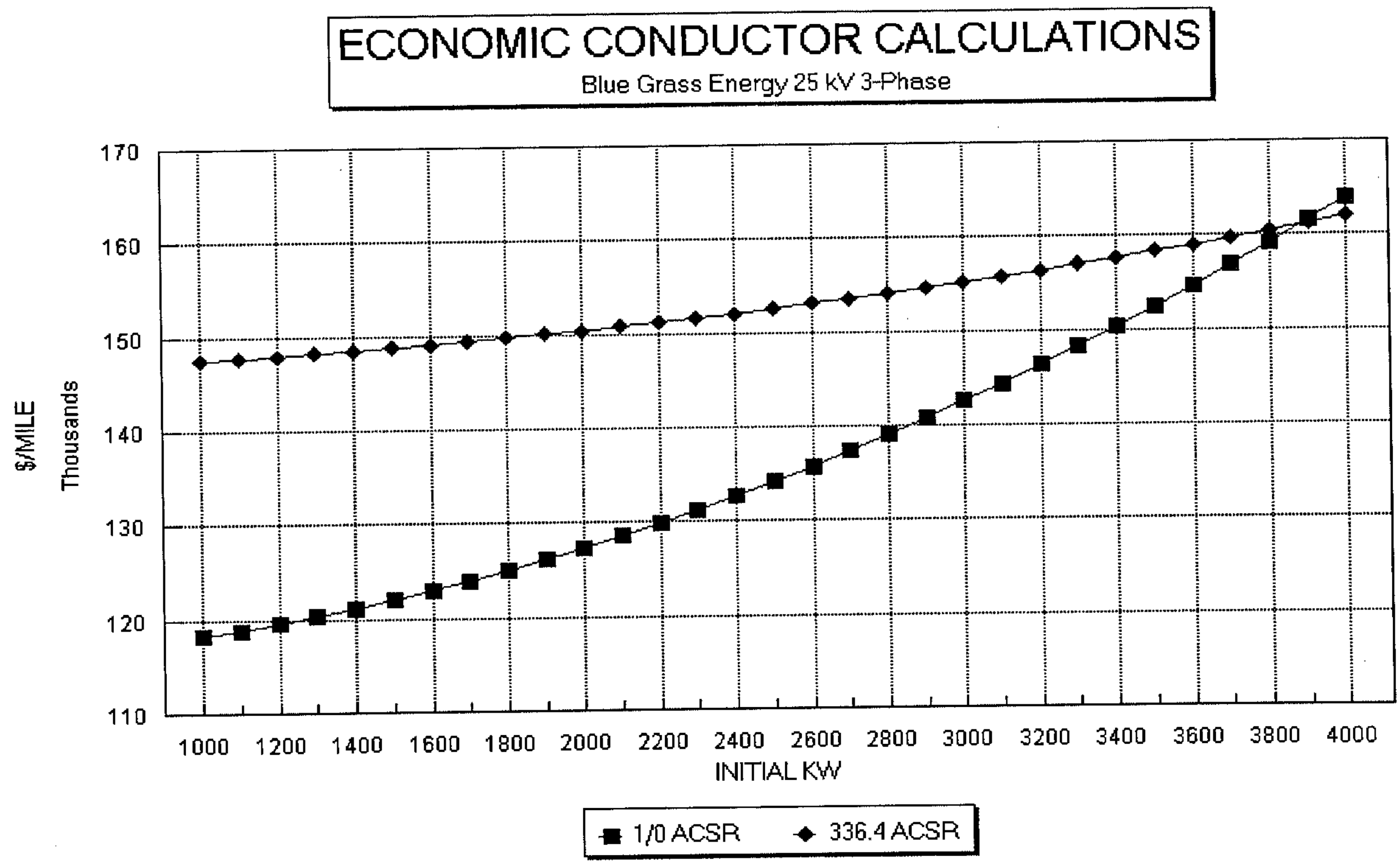
APPENDIX A

Blue Grass Energy Cooperative
25 kV 3-Phase
ECONOMIC CONDUCTOR CALCULATIONS

O&M	TAX	INS	INT	$/KW	$/KWH	KW
4.52%	0.50%	0.37%	5.50%	5.52	0.023	1000
RMO	RAT	KWI	KWHI	LGR	INF	m
12	0.0%	2.00%	2.00%	2.00%	2.50%	30
LF	PF	CF	N	KV	P	
60.0%	94.0%	90.0%	0.52	14.4	3	

CONDUCTOR	1/0 ACSR	336.4 ACSR
COST/MI	$55,000	$70,000
OHMS/MI	0.885	0.278
TCOST/MI	$243,094	$303,894
PWCOST/MI	$118,214	$147,537

APPENDIX A


ECONOMIC CONDUCTOR CALCULATIONS
Blue Grass Energy 25 kV 3-Phase
$/MILE
Thousands
170
160
150
140
130
120
110
1000
1200
1400
1600
1800
2000
2200
2400
2600
2800
3000
3200
3400
3600
3800
4000
INITIAL KW
1/0 ACSR
336.4 ACSR

APPENDIX A

AGED CONDUCTOR SUMMARY

The present Construction Work Plan (CWP) recommends 111 total line miles of conductor for replacement via conversions and ordinary replacement.

The 2004 Long Range Plan (LRP), through improvements and replacements, recommends that 396 total miles of conductor be upgraded or replaced on the distribution system.

The BGE Operations and Engineering staff developed a priority list of aged conductor replacements for this Long Range Plan. This list was based on historical outage and operational data. Through the ten year planning period, additional sections of aged conductor may be replaced as conditions dictate.

Remaining Aged Conductor in Total Miles

8ACWC	6ACWC	#6Steel	2ACWC	#4 ACSR
700	46	9	2	1,350

With approximately 400 of the 2,107 total miles of aged conductor being replaced, it is clear that there will be a large amount of aged conductor remaining at the end of the ten year Long Range planning period. However, after this period, the portions of the system circuitry that will remain as aged conductor will impact the system to a far lesser degree. This is because that most of the more critical sections – with larger numbers of customers – will have been improved based on the recommendations in this plan.

Data Resources

COMPREHENSIVE PLAN

2003

LAWRENCEBURG / ANDERSON COUNTY,

JOINT PLANNING COMMISSION

Prepared by the

Bluegrass Area Development District

BOURBON COUNTY COMPREHENSIVE LAND USE PLAN

including the Cities of Paris, North Middletown, & Millersburg

Adopted August 20, 1992

by the

Bourbon County Joint Planning Commission

Stan Galbraith, Chairman

Ronnie Watts, Vice Chairman

Robert Stone

Frank McCracken, Jr.

John Brennan, Jr.

John Ott, Jr.

Bennie Bridges, Jr.

Walter Lee True

Martin Doyle

William Reed

Ed Marcum

Isaac Ray Keller

Norman Judy

Donnie Foley

Planning Commission Staff

Mark Stewart (Planning Administrator) & Henry Prewitt (Commission Attorney)

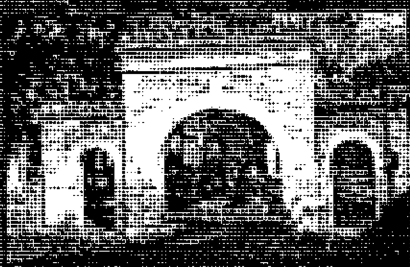
Prepared by the Bluegrass Area Development District (1991 & 1992)

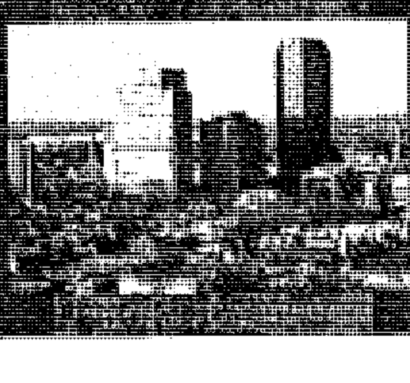
Plan Text, Layout, Graphics & Cartography by

Kent Anness • Regional Planner/Cartographer

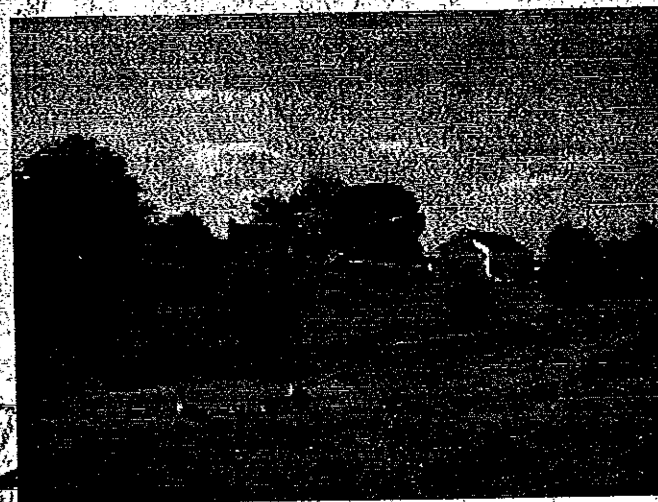
2001 COMPREHENSIVE PLAN UPDATE

LEXINGTON-FAYETTE URBAN COUNTY, KENTUCKY

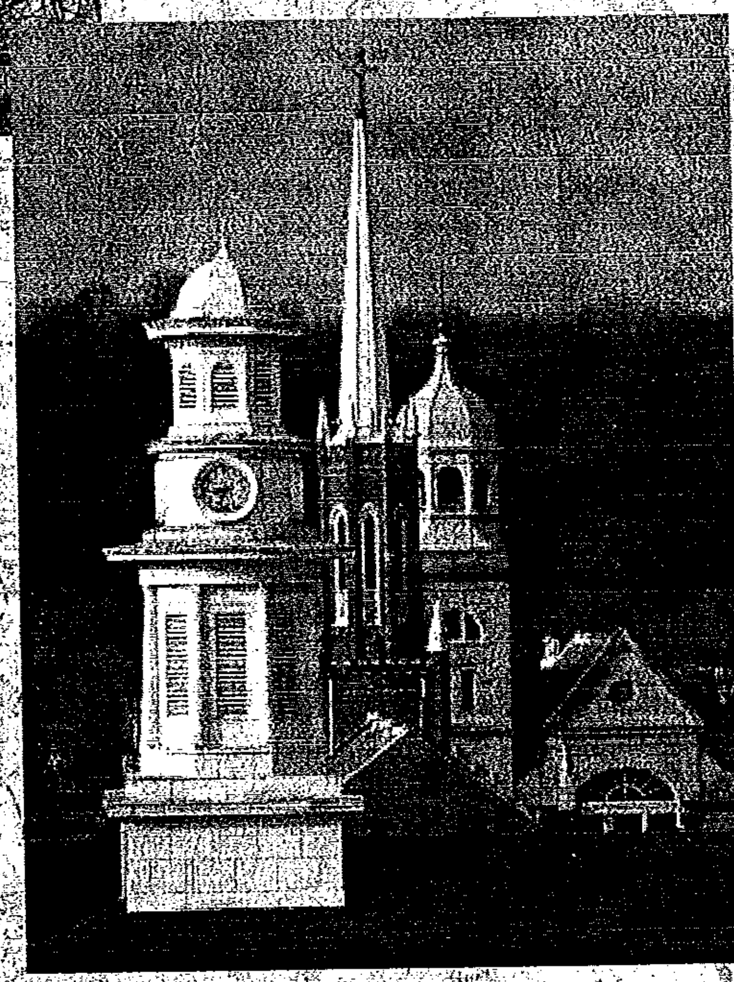




Frankfort
Franklin County
Comprehensive Plan



Adopted January, 2001



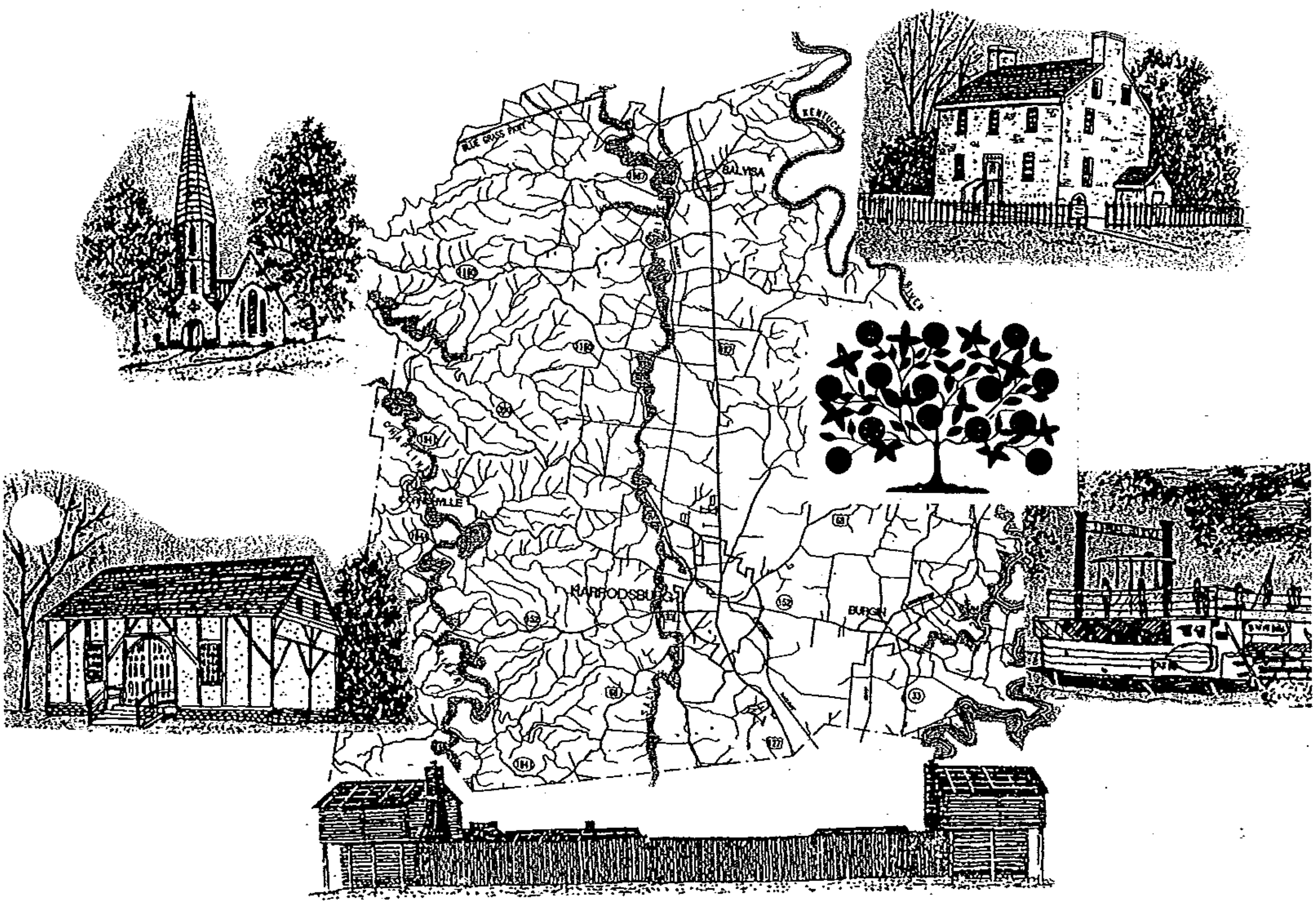
Prepared By:

NEXUS PLANNING

McBride DALE
CLARION

Pflum,
Klausmeier & Gehrum
Consultants, Inc.

HARRODSBURG-MERCER COUNTY COMPREHENSIVE PLAN



ADOPTED

APRIL 7, 1997

Kriss Lowry & Associates, Inc.
227 South Rays Fork Road • Corinth, KY 41010 • (502) 857-2800

JESSAMINE COUNTY/WILMORE
1996 COMPREHENSIVE PLAN

Adopted 4-9-96

Prepared for

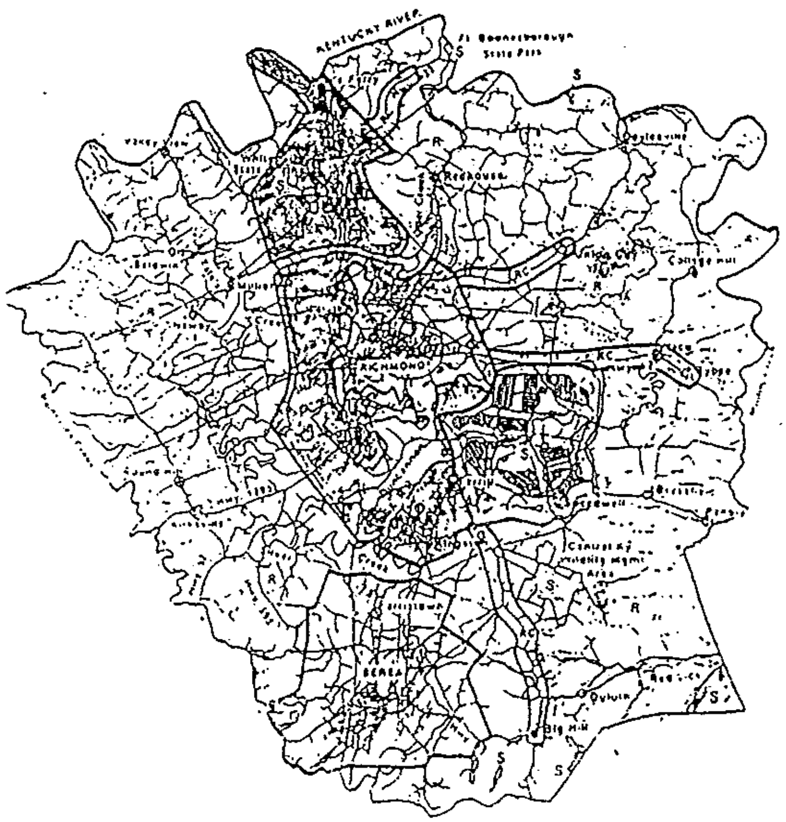
Jessamine County/Wilmore Joint Planning Commission

By the

Bluegrass Area Development District
699 Perimeter Drive
Lexington, Kentucky 40517
Jas Sekhon, Executive Director

MADISON COUNTY
FOUNDATIONS FOR THE FUTURE

A COMPREHENSIVE PLAN



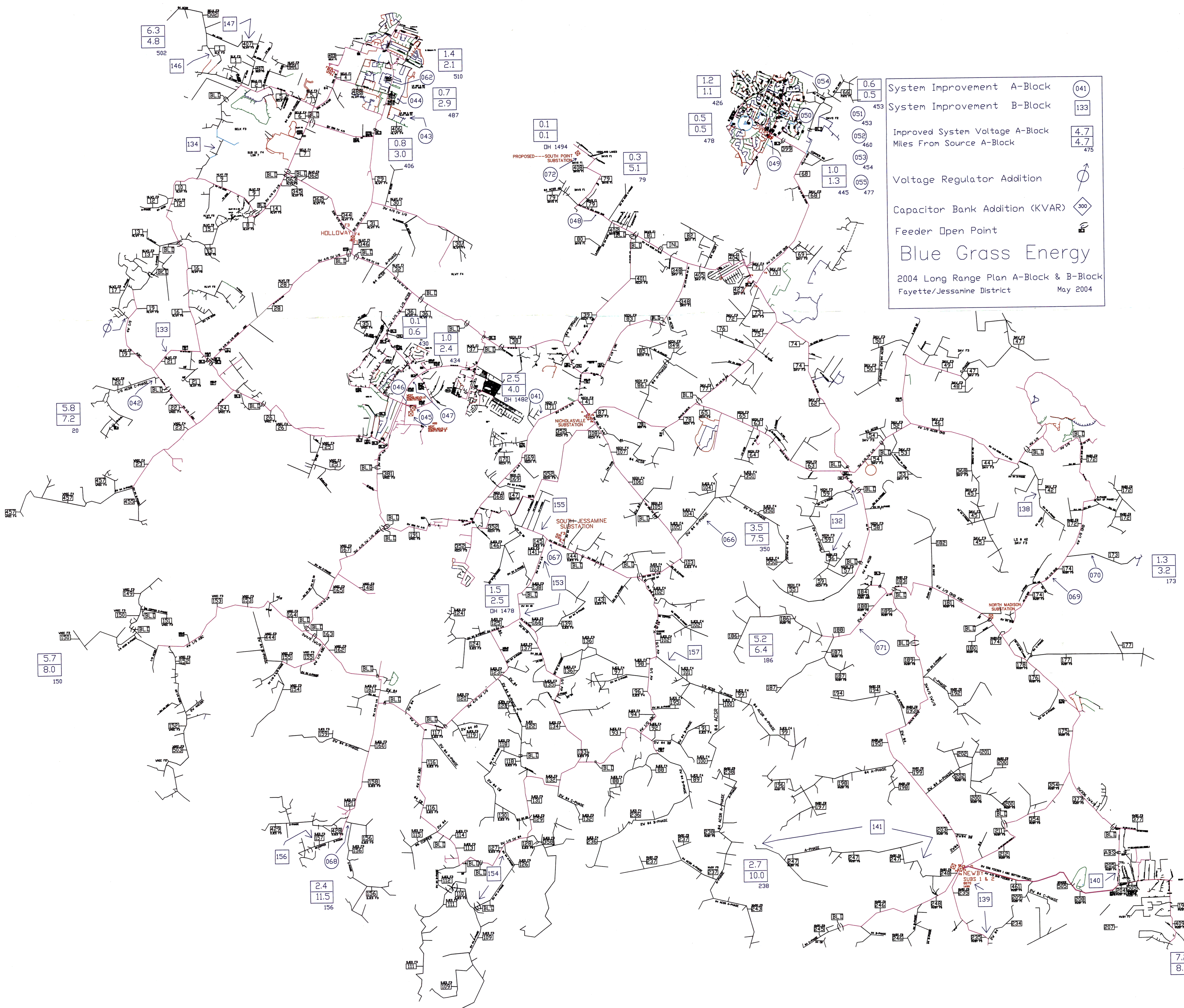
Presented to the
Madison County Fiscal Court
May, 1999

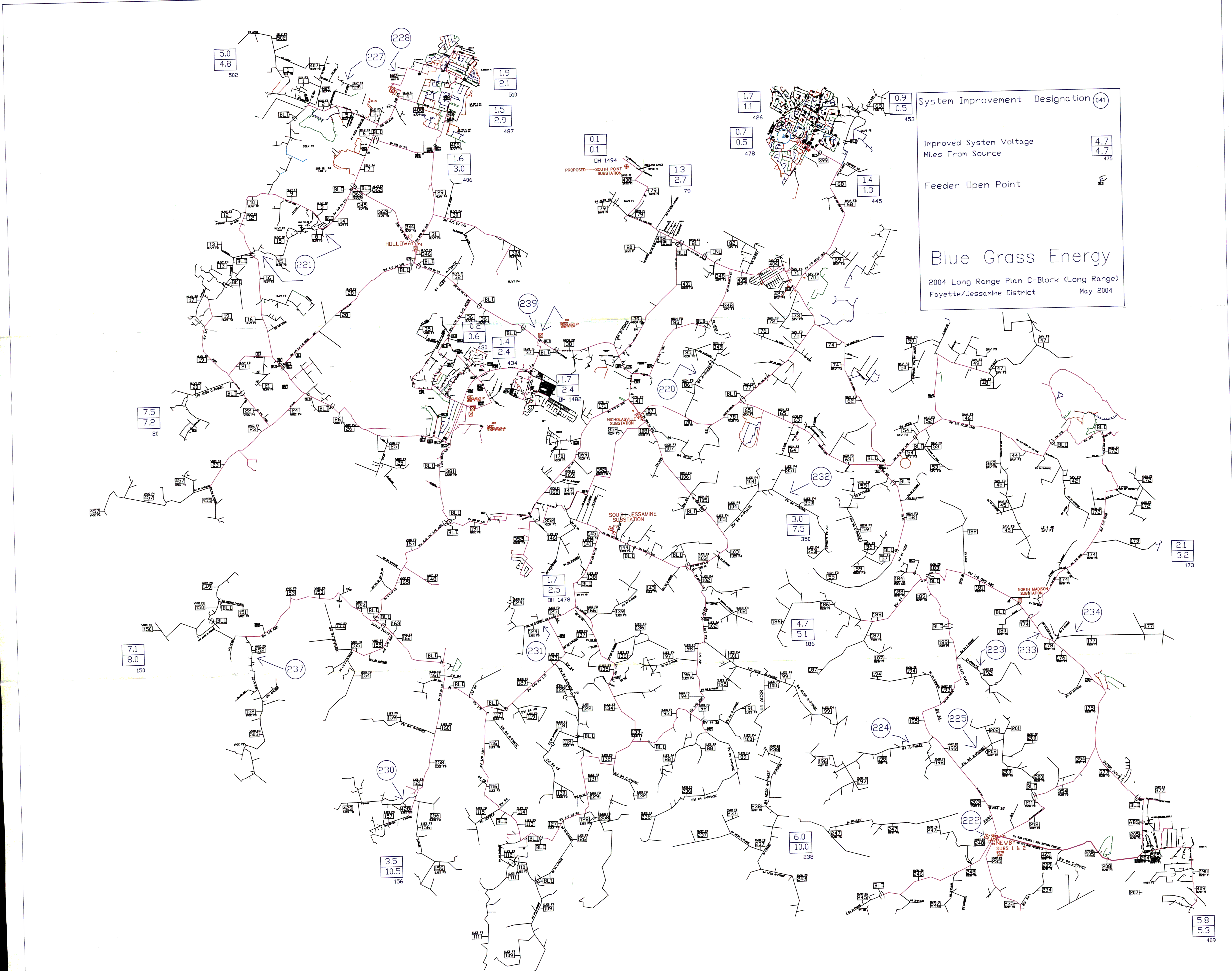
COMPREHENSIVE PLAN
for Georgetown, Sadieville, Stamping Ground,
and Scott County, Kentucky

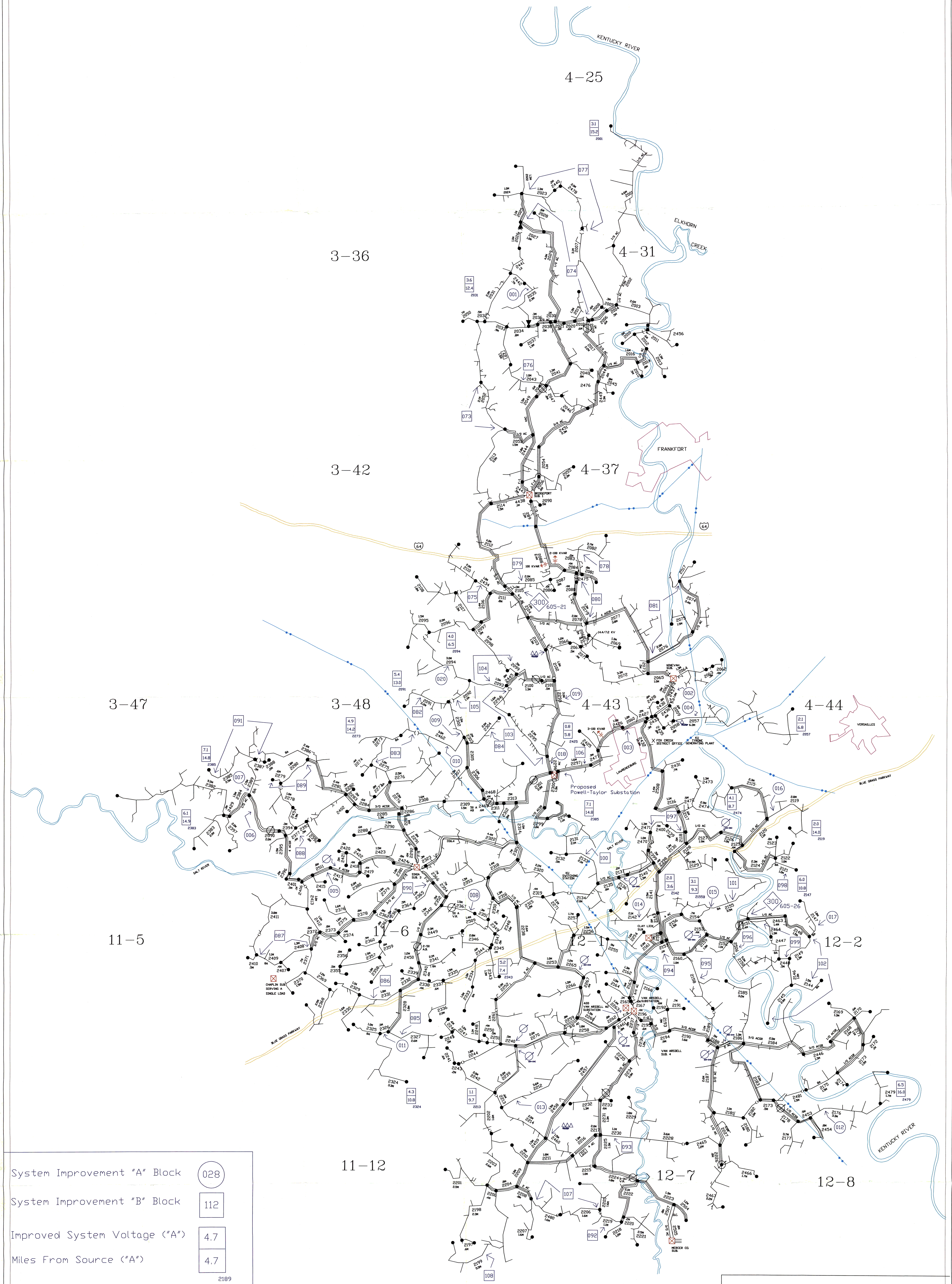
1996 UPDATE

GROWTH AND LAND USE ELEMENT

Circuit Diagrams


System Improvement A-Block
System Improvement B-Block
Improved System Voltage A-Block
Miles From Source A-Block
Voltage Regulator Addition
Capacitor Bank Addition (KVAR)
Feeder Open Point
Blue Grass Energy
2004 Long Range Plan A-Block & B-Block
Fayette/Jessamine District
May 2004
HOLLOWAY
NICHOLASVILLE SUBSTATION
SOUTH JESSAMINE SUBSTATION
NORTH MADISON SUBSTATION
NEWBY SUBS 1 & 2
PROPOSED---SOUTH POINT SUBSTATION


System Improvement Designation
041
Improved System Voltage
Miles From Source
4.7
4.7
475
Feeder Open Point
Blue Grass Energy
2004 Long Range Plan C-Block (Long Range)
Fayette/Jessamine District
May 2004
NICHOLASVILLE SUBSTATION
SOUTH JESSAMINE SUBSTATION
NORTH MADISON SUBSTATION
NEWBY SUBS 1 & 2
HOLLOWAY
PROPOSED---SOUTH POINT SUBSTATION



System Improvement "A" Block — 028

System Improvement "B" Block — 112

Improved System Voltage ("A") — 4.7

Miles From Source ("A") — 4.7

2189

Voltage Regulator Addition

Capacitor Bank Addition (KVAR) — 300

2004 LONG RANGE PLAN

A LOAD LEVEL AND B LOAD LEVEL

Fox Creek District Office

Lawrenceburg, Kentucky

Blue Grass Energy

Drawn By: B.Boyer	May 2004	SCALE: NTS

System Improvement Designation 167

Improved System Voltage 4.7

Miles From Source 4.7

2189

2004 LONG RANGE PLAN

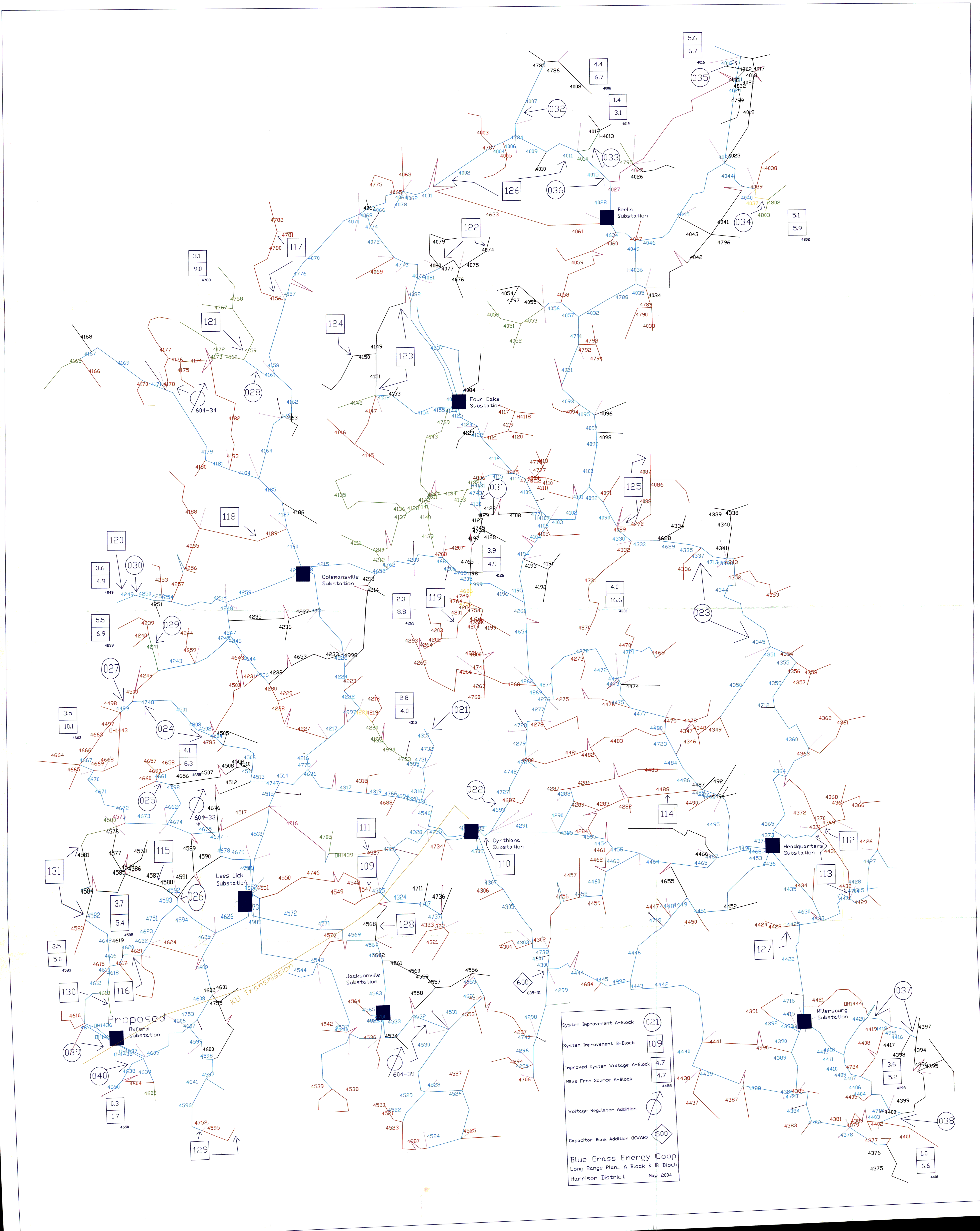
C-Block Load Level (Long Range)

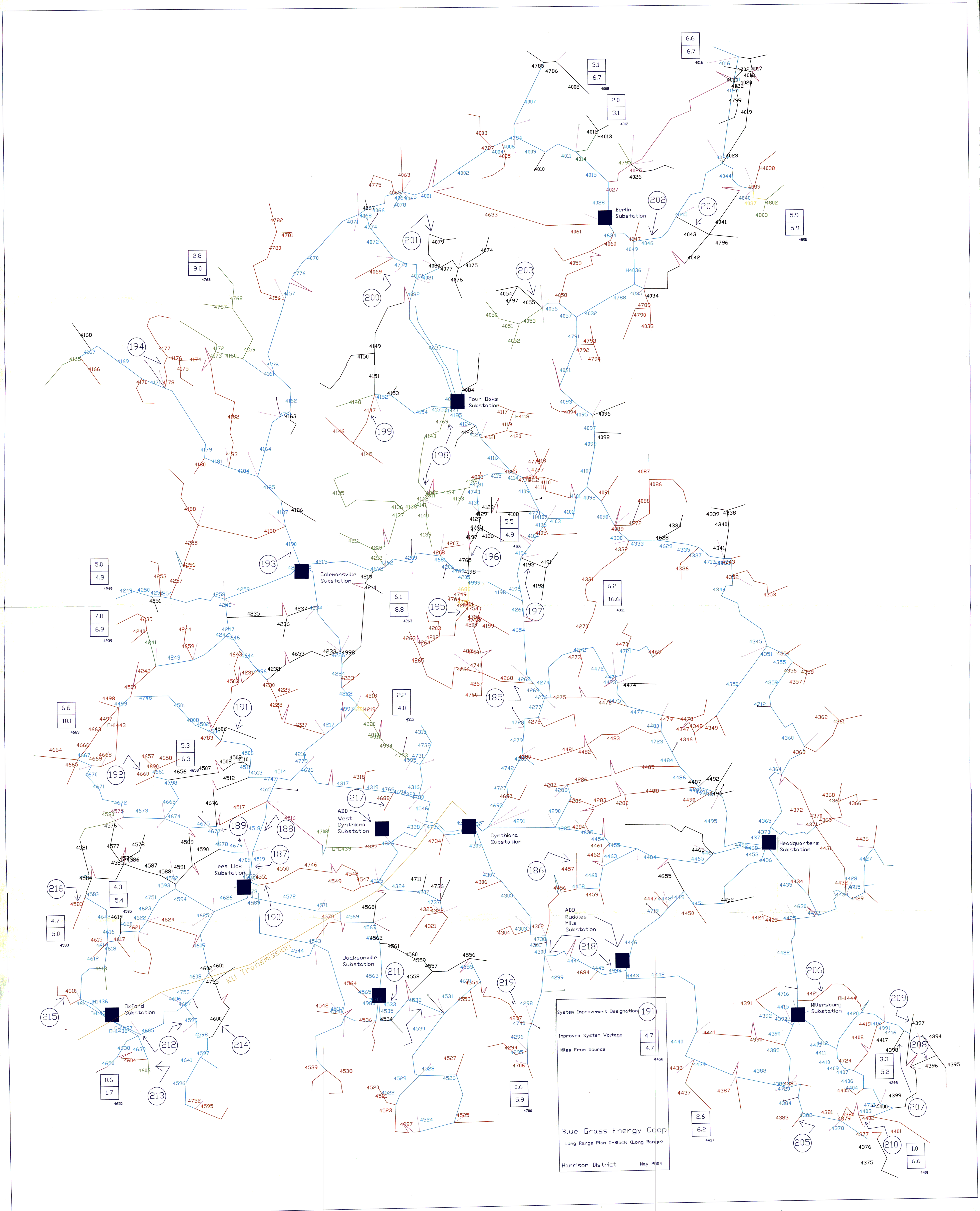
Fox Creek District Office

Lawrenceburg, Kentucky

Blue Grass Energy

Drawn By: B.Boyer	May 2004	SCALE: NTS


System Improvement A-Block 021
System Improvement B-Block 109
Improved System Voltage A-Block 4.7
Miles From Source A-Block 4.7
4458
Voltage Regulator Addition
Capacitor Bank Addition (KVAR) 600
Blue Grass Energy Coop
Long Range Plan_ A Block & B Block
Harrison District
May 2004
Berlin Substation
Four Oaks Substation
Colemansville Substation
Cynthiana Substation
Headquarters Substation
Lees Lick Substation
Jacksonville Substation
Millersburg Substation
Proposed Oxford Substation
KU Transmission



System Improvement Designation
Improved System Voltage
Miles From Source
Blue Grass Energy Coop
Long Range Plan C-Block (Long Range)
Harrison District
May 2004
Berlin Substation
Four Oaks Substation
Colemansville Substation
Cynthiana Substation
ADD West Cynthiana Substation
Lees Lick Substation
Jacksonville Substation
Oxford Substation
ADD Ruddles Mills Substation
Headquarters Substation
Millersburg Substation
KU Transmission
185
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Blue Grass Energy
2004 Long Range Plan A-Block & B-Block
Madison District
May 2004
System Improvement A-Block
045
System Improvement B-Block
162
Improved System Voltage A-Block
Miles From Source A-Block
4.7
4.7
475
Voltage Regulator Addition
Capacitor Bank Addition (KVAR)
300
Feeder Open Point
LEXINGTON - BLUE GRASS ARMY DEPOT
BLUE GRASS ACTIVITY
ARMY DEPOT
DANIEL BOONE
NATIONAL
FOREST
BLUEGRASS ENERGY
JACKSON COUNTY RECC
KIRKSVILLE
Point Lick
HAPPY LANDING
PEYTONTOWN
KINGSTON
Dreyfus
Duluth
Middletown
BEREA COLLEGE
WALLACETON
MADISON CO.
ROCKCASTLE CO.
1.5
5.9
245
6.0
3.1
216
7.2
8.9
258
3.0
10.1
249
6.2
7.6
297
3.8
4.1
440
3.4
4.2
302
6.4
6.1
415
3.6
3.2
287
3.3
10.0
271
3.3
5.3
307
5.6
4.1
240
2.6
8.7
277

System Improvement Designation
235
Improved System Voltage
Miles From Source
4.7
4.7
475
Feeder Open Point
Blue Grass Energy
2004 Long Range Plan C-Block(Long Range)
Madison District
May 2004
LEXINGTON – BLUE GRASS ARMY DEPOT
BLUE GRASS ACTIVITY
ARMY DEPOT
KIRKSVILLE
BLUEGRASS ENERGY
JACKSON COUNTY RECC
DANIEL BOONE
NATIONAL
FOREST