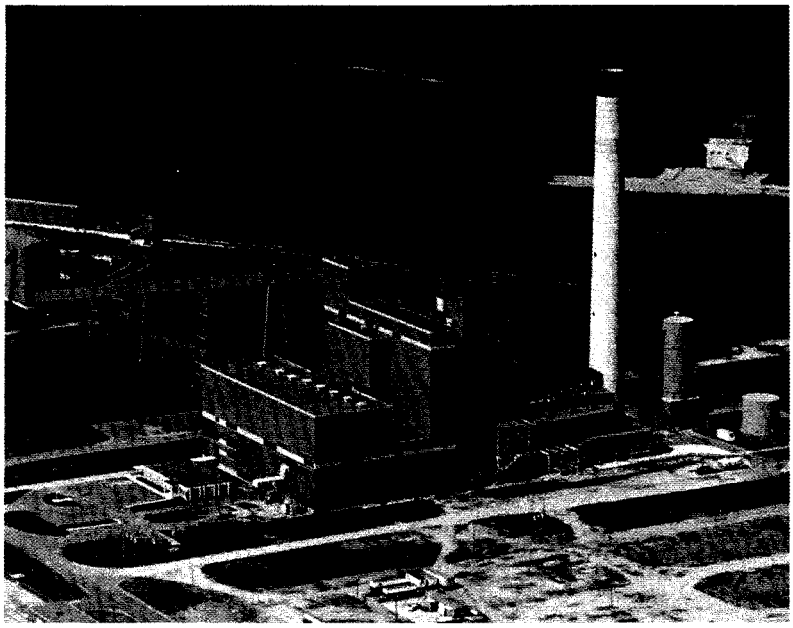
ADDENDUM TO ELECTRIC SYSTEM MASTER PLAN - 2003

VOLUME VII

INTEGRATED RESOURCE PLAN

AUGUST 2005



BOARD OF PUBLIC UTILITIES
KANSAS CITY, KANSAS

KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
VOLUME VII – INTEGRATED RESOURCE PLAN
ADDENDUM TO ELECTRIC SYSTEM MASTER PLAN---2003

Table of Contents

Table of Contents, Continued

Table of Contents, Continued

APPENDICES

KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
VOLUME VII – INTEGRATED RESOURCE PLAN
ADDENDUM TO ELECTRIC SYSTEM MASTER PLAN---2003

I. INTRODUCTION

Integrated Resource Planning (IRP) is a process that involves consideration of demand-side options in addition to traditional supply-side options in meeting the power needs of an electrical system. The importance of such planning is that it focuses on the need to seek and evaluate opportunities for savings of demand and energy in addition to evaluating traditional supply resources. It is an on-going and evolutionary process calling for a re-visit to utility system plans as conditions, prices, costs, technologies and power requirements change. An IRP should anticipate the future and consider the many uncertainties a utility faces. The result of such planning should be a least cost solution to customers for the amount and quality of electric service they desire and it should promote the Utility's long term financial health. A solid long term IRP takes into consideration price elasticity of demand, reliability and quality of service expected.

The Board of Public Utilities of Kansas City, Kansas (BPU) is required by contract to file an Integrated Resource Plan with Western Area Power Administration (WAPA), an Agency of the U.S. Department of Energy, and update the plan every five years. As a part of this requirement, the BPU must also submit annual progress reports on the IRP. This report documents the Integrated Resource Planning that has been and is being done by the BPU. It contains discussions of current activities and recent evaluations, makes recommendations for future studies and suggests measurement strategies for the various programs. Additionally it discusses some of the many benefits realized by BPU and its customers as a result of this planning process.

II. BACKGROUND

Thanks to the Western Area Power Administration (WAPA), the Board of Public Utilities of Kansas City, Kansas was among the first municipally owned systems to undertake Integrated Resource Planning (IRP). WAPA provided the initial exposure of IRP to the BPU, and from the outset WAPA staff has provided invaluable assistance in implementing this program. This planning process continues today and as conditions and technologies change, existing programs are modified and new studies are performed and incorporated into updates of BPU power resource plans.

The initial IRP by BPU was completed in 1989. The cost of that IRP was shared between WAPA and BPU with BPU receiving over $100,000 to prepare the study. The Energy Policy Act requiring an IRP was adopted in 1992. There was an update to the original IRP in 1992 and subsequently there have been studies completed by the BPU with the focus on demand-side opportunities. For example, there was: an in-depth demand-side market assessment dated May 1993; an evaluation of generation powered by landfill gas in June 2003. As a result of this planning and associated studies several programs have been implemented which have provided significant benefit to BPU.

III. APPROACH

There are multiple benefits which can be derived from Integrated Resource Planning. A good practical plan manages risks and minimizes long-run costs. It also encourages energy conservation and the use of renewable energy sources, promotes the use of low cost and more abundant fuels; further, it provides a forum for diverse interests and disciplines to communicate and develop a common goal and select an acceptable resource option.

These benefits are derived from the change of focus in planning, where studies and reviews search for ways to improve energy utilization and revenues. Some of these benefits are, that it has:

1. Improved revenues and contributed to an improvement in net marginal revenue. In general, aided in stabilizing rates and keeping costs down for customers.
2. Assisted in improving the Utility's system load factor allowing better utilization of generating equipment,
3. Increased the use of more efficient generating equipment thus lowering the cost per unit of power generated,
4. Reduced energy use in certain situations by encouraging the use of more efficient appliances and building additions. Consequently this has decreased load growth in peak periods, while at the same time increased non-summer energy uses. These factors assist in improving the system load factor.
5. Assisted in improving public relations and customer satisfaction.

All in all, such planning benefits all customers and helps to minimize the need for rate increases.

Studies done under the IRP umbra have resulted in initiatives which have produced programs that have yielded cost reductions, increased the use of more efficient generating units, enhanced conservation, improved net revenues and in general helped hold down rates. Studies have been made which have focused upon increasing the use of renewable or "green" resources or improving energy conservation. An example of an energy conserving program is the Street Lighting and Signal Light Replacement Program where more efficient lamps are being used to replace older less efficient lamps but still providing the same or greater level of lumens to the area or signal brightness. This is discussed in a later section of this report.

Another benefit is a direct reduction in energy costs. Under an agreement with WAPA, the BPU is required to file an IRP, in return it receives an annual allocation of approximately 4.8 megawatts (MW) of capacity and about 14,900 megawatt-hours (MWh) of hydroelectric power. Receiving this power is a valuable benefit to BPU.

System Load Factor Benefits

It is believed that this planning has contributed to an improvement (increase) in system load factor [a quotient of energy used (kWh) and peak load (kW) times the number of hours in the year]. Generally speaking, an improvement in system load factor is desirable because it allows for greater use of more efficient equipment and lower cost fuel.

An improvement in system load factor occurs when the increase in system energy is greater than the increase in system peak. An improvement in load factor can be due to any number of reasons, such as: energy management programs that control on-peak use; greater efficiency in appliances; more energy efficient residential, commercial and industrial building additions; increased off-peak use; the addition of large industrial loads with high load factors; and

weather factors. Programs implemented as a result of IRP have aided in obtaining an improved load factor.

Improvements in load factor associated with IRP result from the fact that some of the programs implemented have increased off-peak use while others have encouraged conservation or the use of more efficient appliances. The result is that less fuel is used per kWh generated while at the same time there is a increase in the use of more abundant and less costly fuels – coal versus natural gas. Greater use of more abundant and less costly fuels is primarily due to the reduction of the use of energy in peak periods (because of the increased efficiency of appliances being connected) and the fact that more heat pumps and electric hot water heaters are being installed in lieu of gas furnaces and gas hot water heaters. Reductions in peak demand and use also save in the purchase of off-system power.

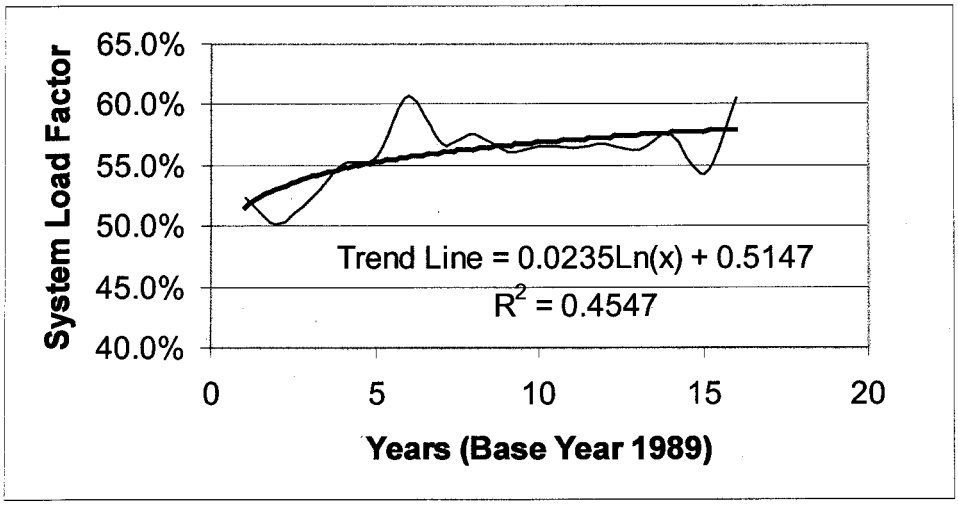
Table 1 below sets out the system load factor for the past 16 years. As can be seen from this table, the system load factor has improved since 1989, the year Integrated Resource Planning started. In 1989 the system load factor was 52.4% at the outset of Integrated Resource Planning, and in 2004 it was 60.5%. This improvement is beneficial, and while not all of the improvement can be attributed to IRP, a portion can be.

Table 1
System Load Factor – 1989 to 2004
Kansas City, Kansas Board of Public Utilities

Year	System Energy MWH	System Peak MW	Load Factor
1989	2,120,142	462	52.4%
1990	2,195,606	499	50.2%
1991	2,232,517	487	52.3%
1992	2,123,359	439	55.1%
1993	2,211,437	452	55.9%
1994	2,234,464	420	60.7%
1995	2,255,271	453	56.8%
1996	2,337,332	462	57.6%
1997	2,354,726	479	56.1%
1998	2,442,491	493	56.6%
1999	2,444,730	495	56.4%
2000	2,464,881	494	56.8%
2001	2,448,989	496	56.4%
2002	2,482,148	492	57.6%
2003	2,470,671	520	54.2%
2004	2,605,000	490	60.5%

Charting the above data yields the graph shown below. This graph shows a positive trend line that is gradually increasing. This chart also shows variation associated with weather and other factors.

Chart 1
System Load Factor 1989 – 2004



The variations in the load factor from year to year are mostly due to weather, but the general trend of improvement is due, at least in part, to the success of many of the programs undertaken by BPU. Some of the major contributors to this improvement have been the:

1. Electric Heat Pump and Hot Water Heater Rebate Program,
2. Changes in the electric rate structure lowering non–summer rates thus encouraging non-summer use and increasing summer rates making energy management programs economically viable.
3. Changes in the standards of the street and signal light replacement program,
4. Implementation of construction standards emphasizing higher efficiency,
5. Emergency Load Reduction Program.

A discussion and documentation of these programs is included in Section V of this report titled "Existing Programs, Initiatives and Recent Studies."

IV. SCREENING OF RESOURCE OPTIONS

General

Resource options for meeting the power requirements of a system are traditionally screened through a power-supply evaluation program. The equipment to be evaluated for supply-side resource is first screened by an assessment of what options are available and most likely viable. In Integrated Resource Planning demand-side options are also considered. The demand-side options considered to be desirable and workable are generally first screened through an assessment of market opportunities. The viable candidates are then placed into the mix of power-supply options for total resource evaluation. This evaluation will indicate what mix of supply-side and demand-side programs should provide the lowest long term cost and should be pursued. The overall evaluation is done through the use of a long-term power supply model.

Screening of demand-side options began at BPU with the first IRP in 1989. Subsequently XENERGY, INC. of Austin, Texas performed a detail screening and market assessment in 1993. This screening analysis became the implementation guide for many of the programs in place today. Additional evaluations have been performed and are discussed in Section VIII of Volume III of the Electric System Master Plan - 2003. This section contains a discussion of green power alternatives that have been reviewed.

V. EXISTING PROGRAMS AND INITIATIVES

Heat Pump and Hot Water Heater Rebate Program

Over the past 4 years records show that the rebate program has benefited the BPU electric system and its customers. This program has made an important contribution to system efficiency, cost and revenues by increasing non-summer use. It has also encouraged the use of more efficient equipment thereby reducing system peak while at the same time increasing off-peak use as a result of switching heating loads to electricity. Both of these effects lead to an improvement in system load factor. The loads gained by the BPU resulting from this rebate program have increased revenues, increased the use of more efficient generating equipment during off-peak hours. This reduces the average cost of generation per kilowatt-hour (kWh). The combined effect of improved revenues and lower generating costs aids in keeping rates low.

The Heat Pump and Hot Water Heater Rebate Program offers distributors, builders, homeowners and commercial business owners financial incentives based upon the expected benefit to the Utility. Different rebates and incentives are offered for the installation of various kinds and sizes of electrical heating equipment.

Residential Rebate Program

Current rebates for residential equipment are given in Table 2 below.

Table 2
Current Residential Rebates

Equipment	Rebate Amount	Rebate Basis
Add on Heat Pump	$ 150	Per Ton
All Electric Heat Pump with Hot Water	$ 1,000	Per Unit
Electric Hot Water Heater (50 Gal)	$ 275	Per Unit
Air Conditioner Change Out	$ 25	Per Ton
Remove Gas Furnace	$ 150	Per Unit

The following Table 3 shows the estimated additional off-peak energy and revenue acquired through application of these rebate values. As one views this table it is useful to keep in mind that as an electrical piece of equipment is added to the system a revenue stream is generated and continues as long as the equipment is connected and used. For this reason the revenue stream accumulates and the annual accumulated revenue grows. This effect is shown in the columns identified as "Cumulative kWh" and "Revenue From Cumulative kWh".

Table 3
Residential Revenue and Rebate Summary[1]

Year	KWh	Cumulative kWh[1]	Net Marginal Revenue per kWh	Revenue from Cumulative kWh	Rebates	Cumulative Rebates
2001	399,200	199,600	$ 0.040	$ 7,978	$ 45,675	$ 45,675
2002	823,200	810,800	$ 0.033	$ 26,610	$ 87,450	$ 133,125
2003	4,150,038	3,297,419	$ 0.035	$ 115,080	$ 241,950	$ 375,075
2004	6,360,876	8,552,876	$ 0.022	$ 188,163	$ 367,650	$ 742,725
Total	11,733,314	11,733,314		$ 337,832	$ 742,725	$ 742,725

The values used in Net Marginal Revenue per kWh vary because of rate structure changes during the period re-defining the summer period. This is also true in the commercial summary below.

It is worthy to note that cumulative residential revenues from 2001 to date are approximately 45% of total rebates given to date. Even if no more residential heat pumps or hot water heaters are added, cumulative additional revenues (from that equipment already added) are expected to exceed the total of all rebates given by 2007.

Another measure of the success of a program is comparing the number of installations to the number of opportunities, that is, the number of units installed in new houses as compared to the number of new houses started. In 2001 only 2 houses (4% of new houses) were credited with having electric heat pumps and hot water heaters, but by 2004 the number of all electric units installed increased to approximately 38.7% of new construction. This data is set out in Table A - 6 of Appendix A.

Commercial Rebate Program
Current rebates for commercial equipment are shown in Table 4 below:

Table 4
Current Commercial Rebates

Equipment	Rebate Amount	Rebate Basis
Heat Pump	$ 125	Per Ton
Resistance Heat	$ 15	Per kW
Apartments with Electric Hot Water Tank	$ 220	Per Unit
Apartments without Hot Water Tank	$ 120	Per Unit
Apartment Hot Water Tank	$ 100	Per Unit

Estimated results of the commercial rebate program are shown below. As in the case of the data for the residential program, data are taken from the monthly marketing summaries and are also included in Appendix A hereof.

[1] It assumed that in the initial year of the connection of an appliance, that only 50% of the estimated additional energy will be sold and additional revenues realized.

Table 5
Commercial Rebate Summary[2]

Year	kWh	Cumulative kWh[2]	Net Marginal Revenue per kWh	Revenue from Cumulative kWh	Rebates	Cumulative Rebates
2001	613,895	306,948	$ 0.024	$ 7,327	$ 33,193	$ 33,193
2002	13,116,384	7,172,087	$ 0.031	$ 221,044	$ 167,933	$ 201,126
2003	57,224,446	42,342,502	$ 0.034	$ 1,418,474	$ 566,046	$ 767,172
2004	13,968,962	77,939,206	$ 0.008	$ 623,514	$ 172,376	$ 939,548
Total	84,923,687	84,923,687		$ 2,270,358	$ 939,548	$ 939,548

All indications are that the commercial rebate program is more beneficial to the BPU than the residential program. Estimated additional total revenues have already exceeded the total of commercial rebates by more than 2 to 1.

Revenue, Rebate and Program Cost Summary
Below is a summary of the combined revenue and rebate amounts from Tables 3 and 5 above. This table also includes an estimate of the annual benefit from the summer peak reductions associated with the retro-fit electric heat program along with an estimate of the annual administrative costs of all rebate programs. Administrative costs and other benefits from capacity savings are detailed in Appendix A. The last column of this table shows the estimate Net Benefit from the program.

Table 6
Combined Program Cost/Benefit Summary

Year	Revenue From Cumulative kWh	Other Benefits (Capacity Savings)	Est. Total Annual Benefits	Rebates	Est. Annual Adm. Costs	Est. Total Cost	Net Benefits
2001	$ 15,305	$ 181	$ 15,486	$ 78,868	$ 124,715	$ 203,583	$ (188,097)
2002	$ 247,654	$ 687	$ 248,341	$ 255,383	$ 241,504	$ 496,887	$ (248,546)
2003	$ 1,533,554	$ 2,023	$ 1,535,577	$ 807,996	$ 332,319	$ 1,140,315	$ 395,262
2004	$ 811,677	$ 7,069	$ 818,746	$ 540,026	$ 328,386	$ 868,412	$ (49,666)
Total	$ 2,608,190	$ 9,960	$ 2,618,150	$ 1,682,273	$ 1,026,924	$ 2,709,197	$ (91,047)

Both the residential and commercial rebate programs are considered successful. The judgement about the residential program is based in part upon the increase in percent of new homes with electric heating units installed during the period from 2001 to 2004 as shown in Table A – 6 in Appendix A of this report. This percentage has increased dramatically over the period going from 4.0% in 2001 to 38.7% in 2004.

Further, the judgement concerning the overall success of these programs is supported by the that fact that total annual benefits to date are estimated to be approximately 97% of total annual cost (which includes not only rebates given but also estimated program administration costs) even though the program is only 4 years old. It is anticipated that positive net benefits will result in the next year or two even if no new units are added. For example, if no new units

[2] It assumed that in the initial year of the connection of an appliance, that only 50% of the estimated additional energy will be sold and additional revenues realized.

are added (no rebates would be given), then based on results of 2004 which had benefits of $818,746 and annual administrative cost of $328,386, benefits will exceed costs by $490,360. If rebates are given (similar to those in 2004) then additional cumulative revenues will be acquired and most likely total benefits will still exceed total cost. These results are principally due to the annual revenue associated with the cumulative kWh of appliances previously connected.

Goals, Measurement Strategy, Metrics and Recommendations

The residential and commercial rebate programs fall within the scope of several specific operational objectives of the BPU Energy Smart Marketing Plan of 2004, namely the objectives of:

1. Reducing the need for critical fuels in the summer.
2. Reducing or postponing capital investment,
3. Holding the line on electric rates,
4. Increasing operating flexibility and optimizing use of system facilities
5. Decreasing unit cost of energy,
6. Minimizing potential environmental impact.

In order to achieve success in fulfilling these objectives the Economic Development and Retail Services Department of the BPU has set out a specific market goal that can be measured. The specific goal is to "acquire 10% of the market as heat pump installations".

Several Metrics develop from these Objectives and Goals. Some are global in nature and relate to overall objectives, while others relate to the specific goal. To track overall success of the program we recommend:

1. Consumption, revenues and count by customer type be tracked for all additions. That these values be separated into categories of program participants and non-participants. In the case of program participants the values should be further categorized as the type of participant, i.e. Heat Pump, Hot Water Heater, etc. Revenues and energy use should be accumulated and kept by season or by month. This will permit benefit/cost values to be calculated accurately and program success to be measured.

2. Actual rebate amounts be kept and tracked for inclusion in the next cost-benefit analysis.

3. Heat pump and electric appliance penetration ratios and market saturation values should be calculated and kept for use in opportunity studies.

4. An in-depth review of this program be made as a part of a future cost-of-service study.

General Summary of Rebate Program

The rebate program is achieving many if not all of its objectives. All evidence indicates the program is successful and cost effective. It is recommended that all these programs be evaluated in depth at the time a future cost-of-service study. Further, it is recommended that the BPU establish a guideline for benefit sharing between the participant and existing customers. Such a guideline will enhance analysis efficiency and establish an important program factor.

Street Light Replacement Program

General

As technology improved and costs decreased, BPU instituted a program of replacing Mercury Vapor lamps (MV) with more efficient High Pressure Sodium (HPS) lamps in its street light replacement program. Subject to budget constraints, more efficient lamps are used when replacement of an existing unit is necessary or when a new lighting facility is installed.

As a result of this program more light (Lumens) per unit of energy is obtained. For, example a 100 Watt High Pressure Sodium Lamp produces approximately 9,500 Lumens, while a 175 Watt Mercury Vapor Lamp produces only 7,850 Lumens. When one considers that a street lighting lamp in the Kansas City area operates approximately 4300 hours per year there is nearly a 43% energy savings for 21% more light. Table 7 below summarizes the Street Light Replacement Program for the last four years.

Table 7
Street Light Replacement Summary

Type	Size Watts	2001 Number in Service	2002 Number in Service	2003 Number in Service	2004[3] Number in Service
High Pressure Sodium (HPS)	100	873	898	933	954
High Pressure Sodium	150	-	10	10	10
High Pressure Sodium	250	4,724	4918	5163	5746
High Pressure Sodium	400	206	206	206	206
Total High Pressure Sodium		5,803	6,032	6,312	6,916
Total HPS kWh		23,848,887	24,022,244	24,356,362	25,028,920
Mercury Vapor (MV)	175	9,530	9426	9234	8914
Mercury Vapor	250	1,714	1712	1712	1716
Mercury Vapor	400	2,393	2389	2389	2389
Mercury Vapor	1000	2,316	2316	2316	2316
Total Mercury Vapor		15,953	15,843	15,651	15,335
Total MV kWh		5,095,001	5,060,330	4,860,376	4,656,115
Grand Total kWh		28,943,888	29,082,574	29,216,738	29,685,035

The program reflected in the above table shows an increase of nearly 19% in HPS lamp units in service and a decrease of approximately 4% in MV units with an increase of only 2.5% in energy. Because of the program, total illumination increases from 424,950,500 lumens to 449,091,400 or 5.6%. The illumination results are shown in Table 8 below. As a result the average energy requirement per lumen has dropped from 0.0681 kWh per lumen in 2001 to 0.066 kWh per lumen in 2004. This is a reduction in usage of approximately 1,509 MWh annually. This amount of energy would supply 151 homes for nearly one year. The savings of this program will continue to grow as more lamp replacements are made and new lamps are installed. Further, the benefits will accrue each year hereafter.

[3] The year 2004 was a leap year and contained approximately 11 more lighting hours.

Table 8
Total Illumination

Type	Size Watts	Lumens per Lamp[4]	Lamp Units in 2001	Total Lumens 2001	Lamp Units in 2004	Total Lumens 2004
HPS	100	9,500	873	8,293,500	954	9,063,000
HPS	150	16,000	-	-	10	160,000
HPS	250	27,500	4,724	129,910,000	5,746	158,015,000
HPS	400	50,000	206	10,300,000	206	10,300,000
			5,803		6,916	
Total Lumens HPS				148,503,500		177,538,000
MV	175	7,850	9,530	74,810,500	8,914	69,974,900
MV	250	12,000	1,714	20,568,000	1,716	20,592,000
MV	400	20,500	2,393	49,056,500	2,389	48,974,500
MV	1000	57,000	2,316	132,012,000	2,316	132,012,000
			15,953		15,335	
Total Lumens MV				276,447,000		271,553,400
Grand Total Lumens				424,950,500		449,091,400

As can be seen above the total illumination increased from 2001 to 2004 it was largely the result of the installation of High Pressure Sodium Lamps.

Details of the program are set out in Table 1 in Appendix B.

Measurement Strategies, Metrics and Summary
All indications are that the replacement program is successful and is having an impact on energy consumption.

In order to evaluate the benefit of the replacement program it is recommended that street light replacements be kept separate from new installations. This will allow the effectiveness of the replacement program to measured and documented.

Signal Light Replacement Program
Further evidence of the BPU's effort to search for energy savings is the Signal Light Replacement Program. Since December 2003 the BPU has replaced (or installed new) over 100 heads of signal lights that had incandescent lamps with lamps having light emitting diodes (LED's). The relative difference in power requirement for each head is significant, being in the range of 20 to 1.

Since the inception of this program the total energy savings is estimated to be nearly 110,000 kWh per year. While this isn't an extremely large value in the overall scheme of things it is enough to provide energy to nearly 11 homes for a year. With the replacement program in place the energy savings will continue to grow. The signal light replacement program is documented below.

[4] Values of Lumens per lamp are taken from the 8th Edition of the Lighting Handbook published by the Illuminating Engineering Society of North America.

Table 9
Signal Light Replacement Program

Location	Item	No. of Heads	LED Wattage/ Head	Total LED Wattage	Normal Wattage (Incadecnt)	Total Normal Wattage	Total Energy Savings/Hour (Watts)
10th & Parallel							
	3 - Section Signal Heads	16	12	192	135	2160	1968
	1 - Section Walk Heads	8	6.5	52	90	720	668
11th & Parallel							
	3 - Section Signal Heads	12	12	144	135	1620	1476
	1 - Section Walk Heads	8	6.5	52	90	720	668
13th & Parallel							
	3 - Section Signal Heads	3	12	36	135	405	369
	1 - Section Walk Heads	1	6.5	6.5	90	90	83.5
90th & Parallel							
	3 - Section Signal Heads	4	12	48	135	540	492
Vilage West & Prairie Crossing							
	1 - Section Walk Heads	8	6.5	52	90	720	668
Village West & France Family Dr.							
	1 - Section Walk Heads	8	6.5	52	90	720	668
Village West @ Cabellas							
	1 - Section Walk Heads	4	6.5	26	90	360	334
Village West & State							
	1 - Section Walk Heads	2	6.5	13	90	180	167
38th & Minnesota							
	3 - Section Signal Heads	6	12	72	135	810	738
	5 - Section Signal Heads	2	12	24	135	270	246
7th & I35							
	3 - Section Signal Heads	23	12	276	135	3105	2829
	1 - Section Walk Heads	4	6.5	26	90	360	334
18th & Pacific							
	Red Only	6	4	24	45	270	246
51st & Kansas							
	3 - Section Signal Heads	2	12	24	135	270	246
K7 & Parallel							
	3 - Section Signal Heads	2	12	24	135	270	246
Totals				1,144		13,590	12,447
Summary Totals							
	5 - Section Signal Heads	2	12	24	135	270	246
	3 - Section Signal Heads	68	12	816	135	9180	8364
	1 - Section Walk Heads	43	6.5	279.5	90	3870	3590.5
	Red Only	6	4	24	45	270	246
	Total			1,144		13,590	12,447
	Annual Energy Savings kWh (8760 Hours)						109,031

Measurement Strategy and Metrics
In order to document the benefits of this program for the periodic updates of the IRP, we recommend that a running record of replacements and new installations be kept as well as a total of remaining signal heads to be replaced.

Emergency Load Reduction Program
General
The BPU has an emergency load reduction program designed to prevent voltage collapse or a condition to develop that would create severe grid problems. This program is implemented once it has been determined that load reduction is necessary. The program is a series of actions and requests done as simultaneously as possible with the development of the condition. The Senior System Operator located at the Energy Control Center initiates the process. These actions and requests are delineated below:

1. Senior System Operator notifies:
    a. Southwest Power Pool,
    b. Supervisor of EMS Operations
    c. Director of Electric System Control
2. Director of Electric System Control notifies
    a. Electric Supply Manager
    b. General Manager of BPU
3. Senior System Operator or member of Energy Control Staff requests:
    a. Load reductions at BPU Facilities
    b. Load reductions at Unified Government Facilities
    c. Requests Public Affairs Officer to implement radio and television appeals for conservation.
    d. As a last resort the Senior System Operator authorizes manual load shedding on a 3-tier priority basis. If interruption is less than 75 MW, rotating outages are implemented on a 15-minute interval.

In addition to the program outlined above the BPU also has an informal program with its larger customers. This informal program is a voluntary program whereby customers in this category are requested to reduce use during periods of emergency conditions.

Reactive Adjustment Rider
General
Customers with low power factors impose a burden on the electrical system causing a utility to increase its generation, transmission, distribution and transformer capacities. Power factors are functions of real power (kW) and the apparent power (kVAr) a utility must supply to the customer. For any given-metered load in kW, the lower the power-factor the greater the amount of power (kVA) a utility must generate and deliver to the customer. For example, in order to supply a load of 100 kW having a power factor of 85% the utility would have to generate and deliver approximately 117 kVA. That would require equipment with 17% more capacity to meet this demand. Further, since system losses vary as the square of the amperage required to serve the load, there is at the same time a 36% increase in system losses. BPU rates are designed to permit a customer to have a power factor equal to or greater than 90%. Customers with power factors less than 90% are penalized.

In August 2003 the power factor penalty provision was changed because the rate structure did not adequately address the cost of low power factors and customers in this category continued to impose a burden on the system. A customer with a low power

factor can correct its power factor by installing corrective equipment or modifying the use of its equipment. When this new reactive adjustment penalty provision was enacted customers were notified of the change and given a six (6) month grace period in which to take corrective action.

Currently customers are notified if they have a low power factor and given a opportunity to correct the problem, if corrective action is not taken within a reasonable period of time then a penalty is added to their bill. The penalty is the difference between 90% and the actual power factor applied to the total customer's monthly electric billing. For example, if a customer has a power factor of 80% then a penalty of 10% is applied to the bill (90% - 80%). Table 10 below shows the history of the reactive adjustment program since records have kept.

Table 10
Power Factor Customer Data
May 2004 – February 2005

Month	Cust. With PF >90%	Cust. With PF < 90%	Total Customers	Power Factor Penalty Revenues
May-04	413	347	760	$ 137,786
Jun-04	475	372	847	$ 151,666
Jul-04	441	414	855	$ 160,830
Aug-04	444	402	846	$ 156,614
Sep-04	464	398	862	$ 160,789
Oct-04	482	377	859	$ 138,370
Nov-04	525	334	859	$ 117,734
Dec-04	580	291	871	$ 111,382
Jan-05	590	281	871	$ 102,618
Feb-05	590	282	872	$ 100,137
Mar-05	592	285	877	$ 100,945
Apr-05	555	321	876	$ 107,524

It is uncertain whether or not the new Reactive Adjustment Rider is working. Records, which have been kept since May 2004 indicate the number of customers with, power factors greater than 90% is increasing. If this trend continues it is a favorable condition and most likely due to the new rider. However, since there is only a 12-month history, this improvement could be due to seasonal or cyclical changes (where customers use different equipment in different parts of the year or under different conditions) or other anomalies.

Recommendation
It is recommended that BPU continue to monitor this matter and continue to move toward an appropirately priced Reactive Adjustment Rider which provides the incentive for customers to correct their own power factor problems.

VI. PROPOSED FUTURE PROGRAMS AND EVALUATIONS

General

To attain increased benefit, beyond what has been achieved to date, BPU intends to initiate or is in the process of initiating studies of additional demand-side or supply-side opportunities that appear viable. Some of these are considered green power resource programs and are thus supply-side while others are demand-side programs. All are considered programs which could improve energy supply or use. This list has been developed from the experience of others or from concepts of BPU staff and consultants and all are considered potentially viable and worthy of additional study. The programs or evaluations being considered are:

1. Evaluation of a Landfill Gas Generator
2. Commercial Account and Key Customer Energy Audit Program,
3. Evaluation of the Purchase of Wind Generated Energy,
4. Evaluation of Local Wind Driven Turbine,
5. Evaluation of Heat Pump and Hot Water Heater Cycling,
6. Evaluation of Renewable Energy Rate (Green Power) Rider,
7. Consideration of holding a "Green Build Conference",
8. Energy Star Program.

These future programs and evaluations are discussed below.

Landfill Gas Generator Evaluation

General

The use of landfill gas (LFG) as a fuel source for electric generation is discussed in Volume III under *Section VIII - Green Power Alternatives* of this master plan. That section is summarized here for the benefit of the reader.

Burns and McDonnell, Consulting Engineers conducted evaluations of two major landfill sites with assistance from the BPU staff. These sites were the Johnson County Landfill and the Forest View Landfill. These evaluations determined that energy projects at either of the sites are technically possible.

The Johnson County Landfill is south of the Kansas River and west of Interstate 435 and is slightly out of the BPU service territory. The landfill is operated by Deffenbaugh Disposal Industries (DDI) and currently has an extensive extraction system with plans for expansion. The system currently produces approximately 2,000 MMBtu/day of pipeline quality methane of 950 to 970 Btu's per cu. ft. DDI has sold the rights to this gas to Cambrian Energy Partners, LLC and South Texas Treaters, Inc. The methane recovered is sold to Enbridge Energy Partners who own a large natural gas pipeline adjacent to the landfill. The LFG apparently is available to purchase at pipeline rates. Based on stated flow rate and a generator efficiency of 37% the site would support approximately 9 megawatts of power. Transmission service from that site would be required.

The Forest View Landfill is within the BPU service territory. It is operated by Allied Waste Industries (AWI). Currently this landfill has a perimeter extraction system and plans are to expand the system. The primary objective of this extraction system is the prevention of off-site migration of LFG. Once the planned expansion is complete the anticipated flow rate is 800 scfm with an energy content between 400 and 500 Btu's per cu. ft. AWI retains the right to this

LFG, with the possible exception of a long-term agreement to provide heating gas to a Unified Government Public Works Facility. The cost of available gas would be negotiated. Based upon energy content and flow rates of LFG at this site it would support a 2.4 mW power generator.

Recommendation
We recommend that an evaluation of a LFG powered electric generation resource ("green power") be made at the Forest View Site. It appears this site will support a 2.4 mW generator with a relatively high level of dependability. At this site there should be no significant transmission issues and such generation may add to BPU's firm capacity.

If this power source were found viable it would make the BPU eligible to be considered as a renewable energy provider and if qualified, would permit BPU to offer Tradable Renewable Certificates (TRC's). The benefit of this qualification is that BPU TRC's could be traded in other markets in addition to this power being sold locally. Locally this power could be offered under a proposed renewable energy rate rider as discussed in Section VI, but in other markets it could be offered as a TRC.

In addition to this LFG generator system possibly providing firm capacity and energy, this project could also have substantial public relations benefits.

Commercial and Key Account Energy Audit Program
In the past BPU has provided energy audits to the residential customer class and in certain instances to the commercial class of customers. An expanded Commercial and Key Account Energy Audit Program is now being considered. There are many facets to the program under consideration, these include:

1. The use of infrared equipment to spot candidates for audit,
2. Notification of key and selected customers about the program,
3. Offering the program upon customer request.

While the program is not fully defined at this point it is considered a worthwhile program and should be implemented in the near future.

Evaluation of the Purchase of Wind Power Energy
The BPU is in discussions with Aquila, Inc. to define cost and terms of purchasing one-megawatt of wind generated capacity and associated energy (green power). This purchase, if successfully negotiated will displace energy generated by fossil fuels. It is to be re-sold within the BPU service territory but the actual rate or rate mechanism has not yet been determined. Once the one megawatt of capacity is sold to BPU customers it is planned to purchase additional capacity, if at that time such capacity is available.

This power is to be generated at the Aquila, Inc wind farm near Montezuma, Kansas. This wind farm is the largest in the state and the largest project in the U.S. not mandated by a State Regulatory Commission.

There are many benefits to this purchase even though the cost is currently higher than the cost of power if it were generated by traditional resources. The positive attributes of this energy are:

1. It avoids pollution and costs with burning fossil fuel,
2. Reduces consumption of non-renewable fuels,
3. Assists in lowering the relative cost difference between renewable and non-renewable energy sources because of scale economies and improving technologies.

Evaluation of Local Wind Driven Turbine

General

In addition to purchasing the wind-generated energy described above, it is recommended that an evaluation be made to determine the economic feasibility of wind generation either in or close to the BPU service area. A discussion of wind power for BPU is contained in Volume III of this master plan. Kansas Corporation Commission (KCC) data on the viability of wind generation shows a low potential for economic wind generation in the BPU service territory. While this information is general in nature specific site information may prove otherwise. Long term monitoring (1 year or longer) at known windy locations in the BPU service territory could be done to validate the potential for wind generation. A wind map for Kansas is included in Appendix D hereof.

The basis for this recommendation is the fact that actual wind conditions vary significantly from area to area depending on elevation, topology, temperature and other ambient conditions. Until such local circumstances and conditions are evaluated the viability of a local project is unknown.

Recommendation

To minimize evaluation costs it is recommended that a recording anemometer (wind speed and direction measurement device) be placed on an existing structure, (such as an elevated water storage tank, or an existing power pole structure) or one erected for the purpose in a location as close as possible to an acceptable site.

In choosing a possible site consideration should be given to the facts that these wind generators could be 200 feet or more high with blades 70 feet or more in length and produce varying levels of sound as they rotate.

It is understood that WAPA has anemometers available for customers to use and will evaluate the data collected for the customer.

Evaluation of Heat Pump and Hot Water Heater Cycling

In the past there has not been a sufficient number of equipment of this type in the BPU service territory to merit a program of this nature. However, in view of the fact that the rebate program for heat pumps and hot water heaters has increased the use of these appliances, together with the fact that there is an increasing number of air-conditioners, the possibility of instituting a successful cycling program is improving. This likelihood of success of this program could be further enhanced if the installation of control equipment was a part of the rebate program. As an example, the rebate might be increased if the new appliance had a control unit included at the time of installation. Because of the benefits such a program could yield, it is recommended that a cost-benefit analysis be made to determine the merits of various approaches to such a program.

Evaluation of Renewable Energy Rate Rider

Hand in hand with the offering of energy from renewable resources ("green power") such as wind power, power generated from waste gases, etc., should be the offering of a rate which will recover any additional costs of that energy without imposing a burden on other rate payers. In as much as BPU is negotiating to purchase one MW of wind generated power and is considering the installation of its own wind generator and other "green power" resources it is now deemed desirable to consider the development of a rider (or rate) to apply to purchases of renewable energy.

In 2004 according to the U.S. Department of Energy there were 33 states that had utilities that offered green power pricing. Of these at least 25 were either municipally owned or cooperatively owned systems. A list of all of these systems is in Appendix C hereof. This list also shows the price and pricing methodology. Almost without exception these systems charged a premium for this power. General information about the programs at: Colorado Springs Utilities, City Utilities of Springfield, Missouri, Boone Electric Cooperatives, Lincoln Electric System, Omaha Public Power District, Edmond Electric, and Snohomish County Public Power District is also contained in Appendix C.

Recommendation
It is recommended that consideration be given to the development of a renewable energy rate rider in a future cost-of-serve study.

Build Green Program
The BPU is a sponsor of the Build Green Program of the Home Builders Association of Greater Kansas City. This is a voluntary program encouraging builders to take a comprehensive approach to home building. This program provides an opportunity for builders to have their new homes rated into one of several levels of "Build Green" classes. Build Green means designing and constructing a home that is kinder and gentler to our environment. This program takes into consideration five categories in rating a new home.

These categories are:
1. Site Conservation
2. Energy Use
3. Material Selection
4. Air Quality
5. Recycling

There are four levels of category participation that a home may achieve, Platinum, Gold, Silver and Bronze. Each level is intended to result in a healthier and more efficient home. The Platinum level is the highest level. The Build Green program offers builders a new enticement package and possibly an increase market share. Such an improvement could result in an improvement in the "bottom line" for the builder.

The BPU is considering sponsoring a "Build Green Conference". The purpose of this conference would be to encourage "green development" in its service territory. Groups and persons invited to attend would be: developers, real-estate agents, architectural students, high-school teachers, the general public and others.

The purposes of the conference would be to; share information about green development and the Build Green Program; to encourage green development and to link parties interested in green-build issues. At this point this program is still in its fermentation stage.

Recommendation
It is recommended that this program be tracked in the BPU service territory. This tracking should include a count by level (Platinum, Gold, etc) and if not too burdensome, statistics on the individual homes. Such tracking will assist in determining the merits of the program.

Energy Star Program
The Energy Star program is a government sponsored program that assists consumers with energy efficient purchases. The program was introduced by the Environmental Protection Agency (EPA) in 1992 as a voluntary labeling program designed to identify and promote energy efficient equipment. In 1995 the EPA partnered with the Department of Energy and

added a multitude of product categories including; major appliances, office equipment, lighting, home electronics, new homes and buildings and more. The Energy Star Label is now on over 40 product categories and assures that the products carrying the label will provide equal to or better performance than other non Energy Star products while at the same time using less energy and saving money. Currently the BPU purchases a limited amount of consumer products within the 40 plus consumer product categories within the Energy Star program. However, new product categories are being added and other rulemakings are in the legislative process for equipment energy efficiency standards including utility distribution transformers.

In the past, our purchasing policies have not included procedures requiring Energy Star information for products within the regulated product categories. Our procedure has been to evaluate products according to the lowest first cost or purchase price--not the lowest life cycle cost--which would include annual operating costs as well as estimated life of the product. Furthermore, any evaluation which took into account long term operating costs priced the energy used in the evaluation at the wholesale cost to generate or the BPU's inter-departmental rate, which is less than the price of energy available to BPU's customers as shown in our published rates. While this is the correct way to calculate energy costs when performing plant equipment evaluations on large industrial motors or transformers, when evaluating a refrigerator, copier or computer, we should evaluate the purchase using the same energy costs that our customers do.

BPU will evaluate alternative guidelines for use in the purchase of equipment for which Energy Star criteria are available. These decisions will be made the same way that we would recommend our customers evaluate a large purchase with emphasis on the saving of energy. The implementation of these guidelines will most likely include employee training and creation of an internal purchasing policy and procedure to encourage employees to evaluate consumer products on the basis of total cost, or life cycle cost, using an energy rate equivalent to our commercial customer energy rate for the highest usage block. This is a first step toward further involvement with the Energy Star Program.

More information on the Energy Star Program can be obtained at the Energy Star website http://www.energystar.gov/.

Public Participation Program

Communication with its customers has always been a hallmark of the BPU operation. At the outset of integrated resource planning in 1989, the BPU established a special Community Power Planning Committee. This committee was for the purpose of providing guidance in the development of viable demand-side and supply-side resources for the community. The committee consisted of 10 voluntary representatives from all segments of the Utility's customer base. Subsequently there have been numerous ad-hoc committees, focus groups and public forums held to obtain public input into important issues of the Utility. In addition to these public forums and meetings with special groups, there have been numerous communiqués to inform the customer base of important events, the status and condition of the system and to offer an opportunity for input into major decisions of the Utility. As an example, there were 16 meetings concerning the location of a new substation and 3 meetings with regard to the transmission line to the facility.

In order to provide ample planning and preparation time for the next IRP update it would be beneficial to develop a "public participation plan". This plan should provide many opportunities for customers to voice their concerns and opinions regarding long-term resource planning. It is recommended that it provide for:

1. The creation of an Overview Advisory Group.
2. The creation of a Technical Advisory Group
3. Focus Groups and Interviews with customers
4. Public hearings on important issues
5. Ample opportunity for input including internet communication with the BPU.
6. Web site posting of activities
7. The listing, posting and distribution of a calendar of events for the next IRP.

VII. ACTION PLAN

Summary

The BPU continues to emphasize broad based planning and to encourage use of energy efficient appliances and devices. The programs, which have been implemented, have been successful and generally improved energy use. None of these programs are recommended to be discontinued. However, some are recommended for review and updating. In addition to the programs in place there are several initiatives that are recommended for analysis and consideration and may end up being included as on-going programs. These initiatives include:

1. A Commercial and Key Accounts Energy Audit Program
2. Planned Purchase of Wind Power Energy
3. Evaluation of Local and/or Wind Driven Turbines
4. Evaluation of Landfill Gas Driven Generator
5. Evaluation of Heat Pump and Hot Water Heater Cycling
6. Development of Renewable Energy Rate Rider.

The proposed timelines for the development and analysis of these programs and initiatives shown in Appendix E. These projects are standalone projects it is not intended that all projects start immediately and run concurrently.

VIII. CONCLUSION

The BPU is devoting considerable resources to the programs either operating or being considered as a part of Integrated Resource Planning. The existing programs are yielding beneficial results. They are aiding in holding down rates, conserving energy, improving use of power generating equipment and reducing the use of limited and more costly fossil fuels. Future programs being considered and listed above are considered worthy of evaluation and if implemented most likely will achieve many of these same results.

Kansas City, Kansas Board of Public Utilities
Volume VII – Integrated Resource Plan
Addendum to Electric System Master Plan – 2003

APPENDICES A – E

Kansas City, Kansas Board of Public Utilities
Volume VII – Integrated Resource Plan
Addendum to Electric System Master Plan – 2003

APPENDIX A

Heat Pump, Electric Heater and Hot Water Heater Data

Kansas City, Kansas Board of Public Utilities
Review of Heat Pump and Hot Water Heater Rebate Program

Table A-1

2001 Commercial & Residential -- Heat Pump, Electric Resistance & Electric Hot Water Tank Marketing Report

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Goal	Total #'s	Total Kwh	Rebate $'s	Yearly Revenue $'s	20C/15R Yr Proj Rev $'s
Commercial Heat Pump																			
AEHP's Units @ 1 T	x	x	x	x	x	x	55	0	0	0	0	0	Units		55				
Tons	x	x	x	x	x	x	265	0	0	0	0	0	Tons		265	610,295	$33,125	$14,568	$291,355
AOHP's DF Units @ 1 T	x	x	x	x	x	x	0	0	0	0	0	0	Units		0				
Tons	x	x	x	x	x	x	0	0	0	0	0	0	Tons		0	-	$0	$0	$0
Apts w/EHWT's	x	x	x	x	x	x	0	0	0	0	0	0	Apts w/T's		0	-	$0	$0	$0
Apts w/o EHWT's	x	x	x	x	x	x	0	0	0	0	0	0	Apts w/o T's		0	-	$0	$0	$0
Commercial Electric Resistance Heat																			
Apts w/EHWT's	x	x	x	x	x	x	0	0	0	0	0	0	Apts w/T's		0				
kW's	x	x	x	x	x	x	0	0	0	0	0	0	kW's		0	-	$0	$0	$0
Apts w/o EHWT's	x	x	x	x	x	x	0	0	0	0	0	0	Apts w/o T's		0				
kW's	x	x	x	x	x	x	0	0	0	0	0	0	kW's		0	-	$0	$0	$0
Electric Resistance Heat kW's	x	x	x	x	x	x	0	0	0	0	0	0	kW's		0	-	$0	$0	$0
Commercial Electric Hot Water Tanks																			
Apt EHWT's	x	x	x	x	x	x	0	0	0	0	0	0	Tanks		0	-	$0	$0	$0
Units <10kW	x	x	x	x	x	x	1	0	0	0	0	0	Units		1	3,600		$88	$1,719
kW's	x	x	x	x	x	x	5	0	0	0	0	0	kW's		5		$68		
Units > 10kW	x	x	x	x	x	x	0	0	0	0	0	0	Units		0	-		$0	$0
kW's	x	x	x	x	x	x	0	0	0	0	0	0	kW's		0		$0		
Residential Heat Pumps																			
AOHP's New Units	x	x	x	x	x	x	41	5	3	6	4	6	Units		65	260,000		$10,392	$155,883
Tons	x	x	x	x	x	x	123	15	15	18	12	18	Tons		201		$30,150		
AEHP's w/ EHWT's Units	x	x	x	x	x	x	0	0	1	1	0	0	Units		2	21,200	$2,000	$847	$12,710
Tons	x	x	x	x	x	x	0	0	4	4	0	0	Tons		8				
AEHP's w/o EHWTs Units	x	x	x	x	x	x	0	0	0	0	0	0	Units		0	-		$0	$0
Tons	x	x	x	x	x	x	0	0	0	0	0	0	Tons		0		$0		
Remove Gas Furnace Unit	x	x	x	x	x	x	0	0	0	0	0	0	Units		0		$0		
Residential Electric Hot Water Tanks																			
EHWT's 4 5kW-50 gal Units	x	x	x	x	x	x	0	0	1	0	3	1	Units		5	18,000	$1,375	$719	$10,792
Residential Air-Conditioner Conversions																			
AOHP's Retro Units	x	x	x	x	x	x	14	2	6	0	2	1	Units		25	100,000		$3,997	$59,955
Tons	x	x	x	x	x	x	42	6	24	0	6	3	Tons		81		$12,150		
A/C Conversion Units	x	x	x	x	x	x	0	0	0	0	0	0	Units		0	-		$0	$0
Tons	x	x	x	x	x	x	0	0	0	0	0	0	Tons		0		$0		
															1,013,095		$78,868	$30,610	$532,414

Ratio of Anticipated Future Revenue to Rebate Investment	6.75		
Rebate Payback In Years	2.59		
Residential Retrofit Summer Peak Reduction at 85% Coincidence Factor	48.88	kW	25 # Residential Retrofit Units

Commercial Calculation Table

Full Load Heating Hours	1600	Annual
Marginal Net Revenue (R-200)	0.024	$/kWh
AEHP's - @ 1 ton ea	2303	kWh/yr
AOHP's Dual Fuel @ 1 ton ea	1380	kWh/yr
EHWT's <10kW	3600	kWh/yr
EHWT's >10kW	15768	kWh/yr
Apts w/EHWT	5600	kWh/yr
Apts w/o EHWT	4000	kWh/yr
Apt EHWT's	1800	kWh/yr

Commercial Rebates ($)

Heat Pump Ton	125	$33,125
Resistance Ht/kw	15	$0
Apts w/EHWT	220	$0
Apts w/o EHWT	120	$0
Apt EHWT's	100	$0
Hot Water Tanks <10kW		$68
Hot Water Tanks >10kW		$0
Total		$33,193

Residential Calculation Table

Full Load Heating Hours	1600	Annual
Marginal Net Revenue	0.040	$/kWh
Base Rate W/ Fuel	0.063	$/kWh
AOHP's New & Retro	4000	kWh/yr
AEHP's w/ EHWT's	10600	kWh/yr
AEHP's w/o EHWT's	7000	kWh/yr
EHWT's 4 5 kW 50 gal	3600	kWh/yr
A/C Conversions	-1000	kWh/yr
Summer Peak Reduction	2.3	kW

Residential Rebates ($)

AOHP's per Ton	150	$30,150
AEHP's w/ EHWT	1000	$2,000
EHWT's 50 gal +	275	$1,375
A/C's per Ton	25	$12,150
Rem Gas Furnane	150	$0
Total		$45,675
Grand Total Rebates		$78,868

Total Rebates

Kansas City, Kansas Board of Public Utilities
Review of Heat Pump and Hot Water Heater Rebate Program

Table A-2

2002 Commercial & Residential -- Heat Pump, Electric Resistance & Electric Hot Water Tank Marketing Report

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Goal	Total #'s	Total Kwh	Rebate $'s	Yearly Revenue $'s	20C/15R Yr Proj Rev $'s
Commercial Heat Pump																			
AEHP's Units @ 1 T	0	31	0	3	0	58	0	0	0	1	104	0	Units	61	197				
Tons	0	97	0	12	0	158	0	0	0	3	104	0	Tons	292	373	859,480	$46,650	$26,489	$529,783
AOHP's DF Units @ 1 T	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0				
Tons	0	0	0	0	0	0	0	0	0	0	0	0	Tons	0	0	0	$0	$0	$0
Apts w/EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/T's	0	0	0	$0	$0	$0
Apts w/o EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/o T's	0	0	0	$0	$0	$0
Commercial Electric Resistance Heat																			
Apts w/EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/T's	0	0				
kW's	0	0	0	0	0	0	0	0	0	0	0	0	kW's	0	0	0	$0	$0	$0
Apts w/o EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/o T's	0	0				
kW's	0	0	0	0	0	0	0	0	0	0	0	0	kW's	0	0	0	$0	$0	$0
Electric Resistance Heat kW's	0	9	0	311	0	0	0	6284	37	0	724	136	kW's	38762	7501	12,000,800	$112,508	$389,865	$5,547,970
Commercial Electric Hot Water Tanks																			
Apt EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Tanks	0	0	0	$0	$0	$0
Units <10kW	0	0	0	0	0	58	0	0	0	0	0	0	Units	1	58	208,800		$8,435	$128,704
kW's	0	0	0	0	0	261	0	0	0	0	0	0	kW's	5	261		$3,915		
Units > 10kW	0	0	0	0	0	0	0	0	0	0	3	0	Units	0	3	47,304		$1,458	$29,158
kW's	0	0	0	0	0	0	0	0	0	0	324	0	kW's	0	324		$4,860		
Residential Heat Pumps																			
AOHP's New Units	8	1	13	10	5	6	8	7	18	7	12	9	Units	72	104	416,000		$13,653	$204,797
Tons	24	3	39	30	15	18	24	21	54	21	36	27	Tons	221	312		$46,800		
AEHP's w/ EHWT's Units	1	0	0	1	1	3	3	2	0	3	1	1	Units	2	16	169,600	$16,000	$5,566	$83,494
Tons	4	0	0	4	4	12	12	8	0	12	4	4	Tons	9	64				
AEHP's w/o EHWTs Units	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0	0		$0	$0
Tons	0	0	0	0	0	0	0	0	0	0	0	0	Tons	0	0		$0		
Remove Gas Furnace Unit	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0		$0		
Residential Electric Hot Water Tanks																			
EHWT's 4.5kW-50 gal Units	1	0	0	0	1	0	1	1	9	0	2	1	Units	6	16	57,600	$4,400	$1,890	$28,356
Residential Air-Conditioner Conversions																			
AOHP's Retro Units	2	0	5	4	5	6	4	7	4	1	4	3	Units	28	45	180,000		$5,908	$88,614
Tons	6	0	15	12	15	18	12	21	12	3	12	9	Tons	89	135		$20,250		
A/C Conversion Units	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0	-		$0	$0
Tons	0	0	0	0	0	0	0	0	0	0	0	0	Tons	0	0		$0		
																13,939,584	$255,383	$431,264	$6,640,877

Ratio of Anticipated Future Revenue to Rebate Investment	26.00		
Rebate Payback in Years	0.67		
Residential Retrofit Summer Peak Reduction at 85% Coincidence Factor	87.98	kW	45 # Residential Retrofit Units

Commercial Calculation Table

Full Load Heating Hours	1600	Annual
Marginal Net Revenue (R-200)	0.031	$/kWh
AEHP's - @ 1 ton ea	2303	kWh/yr
AOHP's Dual Fuel @ 1 ton ea	1380	kWh/yr
EHWT's <10kW	3600	kWh/yr
EHWT's >10kW	15768	kWh/yr
Apts w/EHWT	5600	kWh/yr
Apts w/o EHWT	4000	kWh/yr
Apt EHWT's	1800	kWh/yr

Commercial Rebates ($)		Total Rebates
Heat Pump Ton	125	$46,650
Resistance Ht/kw	15	$112,508
Apts w/EHWT	220	$0
Apts w/o EHWT	120	$0
Apt EHWT's	100	$0
Hot Water Tanks <10kW		$3,915
Hot Water Tanks >10kW		$4,860
Total		$167,933

Residential Calculation Table

Full Load Heating Hours	1600	Annual
Marginal Net Revenue	0.033	$/kWh
Base Rate W/ Fuel	0.063	$/kWh
AOHP's New & Retro	4000	kWh/yr
AEHP's w/ EHWT's	10600	kWh/yr
AEHP's w/o EHWT's	7000	kWh/yr
EHWT's 4.5 kW 50 gal	3600	kWh/yr
A/C Conversions	-1000	kWh/yr
Summer Peak Reduction	2.3	kW

Residential Rebates ($)		Total Rebates
AOHP's per Ton	150	$46,800
AEHP's w/ EHWT	1000	$16,000
EHWT's 50 gal +	275	$4,400
A/C's per Ton	25	$20,250
Rem Gas Furnane	150	$0
Total		$87,450
Grand Total Rebates		$255,383

Kansas City, Kansas Board of Public Utilities
Review of Heat Pump and Hot Water Heater Rebate Program

Table A-3

2003 Commercial & Residential -- Heat Pump, Electric Resistance & Electric Hot Water Tank Marketing Report

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Goal	Total #'s	Total Kwh	Rebate $'s	Yearly Revenue $'s	20C/15R Yr Proj Rev $'s
Commercial Heat Pump																			
AEHP's Units @ 1 T	0	1	0	12	0	0	0	0	77	0	4	0	Units	217	94				
Tons	0	4	0	137	0	0	0	0	58	0	46	0	Tons	411	245	563,774	$30,600	$18,886	$377,729
AOHP's DF Units @ 1 T	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0				
Tons	0	0	0	0	0	0	0	0	0	0	0	0	Tons	0	0	0	$0	$0	$0
Apts w/EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/T's	0	0	0	$0	$0	$0
Apts w/o EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/o T's	0	0	0	$0	$0	$0
Commercial Electric Resistance Heat																			
Apts w/EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/T's	0	0				
kW's	0	0	0	0	0	0	0	0	0	0	0	0	kW's	0	0	0	$0	$0	$0
Apts w/o EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/o T's	0	0				
kW's	0	0	0	0	0	0	0	0	0	0	0	0	kW's	0	0	0	$0	$0	$0
Electric Resistance Heat kW's	0	776	0	117	10500	10000	12414	0	947	0	100	385	kW's	38762	35239	56,381,600	$528,578	$1,888,784	$28,331,754
Commercial Electric Hot Water Tanks																			
\	0	0	0	0	0	0	0	0	0	0	0	0	Tanks	0	0	0	$0	$0	$0
Units <10kW	0	55	0	2	0	0	1	0	0	0	2	0	Units	64	60	216,000		$7,236	$144,720
kW's	0	240	0	9	0	0	2	0	0	0	9	0	kW's	287	260		$3,898		
Units > 10kW	0	0	0	0	0	0	0	0	3	0	0	1	Units	3	4	63,072		$2,113	$42,258
kW's	0	0	0	0	0	0	0	0	162	0	0	36	kW's	356	198		$2,970		
Residential Heat Pumps																			
AOHP's New Units	4	12	16	18	6	7	23	19	11	24	4	6	Units	114	150	1,243,650		$43,403	$651,051
Tons	15	41	50	58	20	28	74	60	35	77	13	18	Tons	343	487.5		$73,125		
AEHP's w/ EHWT's Units	16	12	0	12	3	7	2	19	6	16	6	12	Units	18	111	1,933,398	$111,000	$67,476	$1,012,134
Tons	38	29	0	29	12	17	5	42	13	39	25	25	Tons	70	271.5				
AEHP's w/o EHWT's Units	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0	0		$0	$0
Tons	0	0	0	0	0	0	0	0	0	0	0	0	Tons	0	0		$0		
Remove Gas Furnace Unit	0	0	1	2	1	0	0	0	2	1	2	3	Units	0	12		$1,800		
Residential Electric Hot Water Tanks																			
EHWT's 4.5kW-50 gal Units	4	1	3	7	7	1	1	7	9	11	5	7	Units	18	63	226,800	$17,325	$7,915	$118,730
Residential Air-Conditioner Conversions																			
AOHP's Retro Units	4	2	10	12	8	9	4	8	10	10	3	10	Units	50	90	746,190		$26,042	$390,630
Tons	14	3	23	34	22	22	11	26	32	29	13	33	Tons	149	258		$38,700		
A/C Conversion Units	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0	-		$0	$0
Tons	0	0	0	0	0	0	0	0	0	0	0	0	Tons	0	0		$0		

Ratio of Anticipated Future Revenue to Rebate Investment	38.45			61,374,484	$807,995	$2,061,855	$31,069,006
Rebate Payback in Years	0.46						
Residential Retrofit Summer Peak Reduction at 85% Coincidence Factor	175.95	kW	90	**# Residential Retrofit Units**			

Commercial Calculation Table

Full Load Heating Hours	1600	Annual
Marginal Net Revenue (R-200)	0.034	$/kWh
AEHP's - @ 1 ton ea	2303	kWh/yr
AOHP's Dual Fuel @ 1 ton ea	1380	kWh/yr
EHWT's <10kW	3600	kWh/yr
EHWT's >10kW	15768	kWh/yr
Apts w/EHWT	5600	kWh/yr
Apts w/o EHWT	4000	kWh/yr
Apt EHWT's	1800	kWh/yr

Commercial Rebates ($)

Heat Pump Ton	125	$30,600
Resistance Ht/kw	15	$528,578
Apts w/EHWT	220	$0
Apts w/o EHWT	120	$0
Apt EHWT's	100	$0
Hot Water Tanks <10kW		$3,898
Hot Water Tanks >10kW		$2,970
Total		$566,045

Residential Calculation Table

Full Load Heating Hours	1600	Annual
Marginal Net Revenue	0.035	$/kWh
Base Rate W/ Fuel	0.063	$/kWh
AOHP's New & Retro	8291	kWh/yr
AEHP's w/ EHWT's	17418	kWh/yr
AEHP's w/o EHWT's	13818	kWh/yr
EHWT's 4.5 kW 50 gal	3600	kWh/yr
A/C Conversions	-1000	kWh/yr
Summer Peak Reduction	2.3	kW

Residential Rebates ($)

AOHP's per Ton	150	$73,125
AEHP's w/ EHWT	1000	$111,000
EHWT's 50 gal +	275	$17,325
A/C's per Ton	25	$38,700
Rem Gas Furnane	150	$1,800
Total		$241,950
Grand Total Rebates		$807,995

Kansas City, Kansas Board of Public Utilities
Review of Heat Pump and Hot Water Heater Rebate Program

Table A - 4

2004 Commercial & Residential -- Heat Pump, Electric Resistance & Electric Hot Water Tank Marketing Report

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		Goal	Total #'s	Total Kwh	Rebate $'s	Yearly Revenue $'s	20C/15R Yr Proj Rev $'s
Commercial Heat Pump																			
AEHP's Units @ 1 T	0	0	4	0	0	141	4	0	0	0	1	0	Units	103	150				
Tons	0	0	20	0	0	320	20	0	0	0	3	0	Tons	269	363	834,838	$45,313	$6,679	$133,574
AOHP's DF Units @ 1 T	0	0	0	0	0	0	0	2	0	0	0	0	Units	0	2				
Tons	0	0	0	0	0	0	0	9	0	0	0	0	Tons	0	9	12,420	$1,125	$99	$1,987
Apts w/EHWT's	0	5	0	0	0	0	0	0	0	0	0	0	Apts w/T's	0	5	28,000	$1,100	$224	$4,480
Apts w/o EHWT's	0	20	0	0	0	0	0	0	0	0	0	0	Apts w/o T's	0	20	80,000	$2,400	$640	$12,800
Commercial Electric Resistance Heat																			
Apts w/EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/T's	0	0				
kW's	0	0	0	0	0	0	0	0	0	0	0	0	kW's	0	0	0	$0	$0	$0
Apts w/o EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Apts w/o T's	0	0				
kW's	0	0	0	0	0	0	0	0	0	0	0	0	kW's	0	0	0	$0	$0	$0
Electric Resistance Heat kW's	110	0	0	236	0	632	30	253	0	6809	30	96	kW's	38762	8095	12,952,000	$121,425	$103,616	$1,554,240
Commercial Electric Hot Water Tanks																			
Apt EHWT's	0	0	0	0	0	0	0	0	0	0	0	0	Tanks	0	0	0	$0	$0	$0
Units <10kW	0	0	0	0	0	0	0	1	0	1	2	0	Units	66	4	14,400		$115	$2,304
kW's	0	0	0	0	0	0	0	5	0	3	6	0	kW's	286	14		$203		
Units > 10kW	0	0	2	0	0	0	1	0	0	0	0	0	Units	4	3	47,304		$378	$7,569
kW's	0	0	30	0	0	0	24	0	0	0	0	0	kW's	218	54		$810		
Residential Heat Pumps																			
AOHP's New Units	23	21	24	23	24	12	20	16	21	34	16	12	Units	165	246	2,039,586		$44,871	$673,063
Tons	76	67	80	74	78	35	67	50	67	114	51	38	Tons	536	794.5		$119,175		
AEHP's w/ EHWT's Units	1	4	27	7	16	16	20	8	21	7	25	19	Units	122	171	2,978,478	$171,000	$65,527	$982,898
Tons	3	9	68	16	47	44	50	14	51	24	60	45	Tons	299	429				
AEHP's w/o EHWTs Units	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0	0		$0	$0
Tons	0	0	0	0	0	0	0	0	0	0	0	0	Tons	0	0		$0		
Remove Gas Furnace Unit	1	0	2	0	0	0	1	2	2	3	4	4	Units	13	19		$2,850		
Residential Electric Hot Water Tanks																			
EHWT's 4.5kW-50 gal Units	6	1	4	2	2	3	6	7	20	4	5	9	Units	69	69	248,400	$18,975	$5,465	$81,972
Residential Air-Conditioner Conversions																			
AOHP's Retro Units	17	2	13	7	12	12	12	14	16	3	12	12	Units	99	132	1,094,412		$24,077	$361,156
Tons	47	5	33	21	32	34	37	41	44	9	38	33	Tons	284	371		$55,650		
A/C Conversion Units	0	0	0	0	0	0	0	0	0	0	0	0	Units	0	0	-		$0	$0
Tons	0	0	0	0	0	0	0	0	0	0	0	0	Tons	0	0		$0		

Ratio of Anticipated Future Revenue to Rebate Investment	7.07		**20,329,838**	**$540,025**	**$251,691**	**$3,816,043**
Rebate Payback in Years	2.48					
Residential Retrofit Summer Peak Reduction at 85% Coincidence Factor	258.06	kW	132	**# Residential Retrofit Units**		

Commercial Calculation Table

Full Load Heating Hours	1600	Annual
Marginal Net Revenue (R-200)	0.008	$/kWh
AEHP's - @ 1 ton ea	2303	kWh/yr
AOHP's Dual Fuel @ 1 ton ea	1380	kWh/yr
EHWT's <10kW	3600	kWh/yr
EHWT's >10kW	15768	kWh/yr
Apts w/EHWT	5600	kWh/yr
Apts w/o EHWT	4000	kWh/yr
Apt EHWT's	1800	kWh/yr

Commercial Rebates ($)

Heat Pump Ton	125	$46,438
Resistance Ht/kw	15	$121,425
Apts w/EHWT	220	$0
Apts w/o EHWT	120	$2,400
Apt EHWT's	100	$1,100
Hot Water Tanks <10kW		$203
Hot Water Tanks >10kW		$810
Total		########

Residential Calculation Table

Full Load Heating Hours	1600	Annual
Marginal Net Revenue	0.022	$/kWh
Base Rate W/ Fuel	0.063	$/kWh
AOHP's New & Retro	8291	kWh/yr
AEHP's w/ EHWT's	17418	kWh/yr
AEHP's w/o EHWT's	13818	kWh/yr
EHWT's 4.5 kW 50 gal	3600	kWh/yr
A/C Conversions	-1000	kWh/yr
Summer Peak Reduction	2.3	kW

Residential Rebates ($)

AOHP's per Ton	150	$119,175
AEHP's w/ EHWT	1000	$171,000
EHWT's 50 gal +	275	$18,975
A/C's per Ton	25	$55,650
Rem Gas Furnane	150	$2,850
Total		$367,650
Grand Total Rebates		$540,025

1125

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Kansas City, Kansas Board of Public Utilities
Review of Heat Pump and Hot Water Heater Rebate Program

Table A - 5
Revenue and Unit Summary

Residential

Equipment	2001 Units	2002 Units	2003 Units	2004 Units	Total Units	Estimated Revenue Per Unit	Justified Exp. Per Unit	Total JE to Date	JE Based upon PV Method	Total JE to Date Based on PV Method
Add on Heat Pump	65	104	150	246	565	$ 182	$ 2,432	$ 1,374,080	$ 1,980	$ 1,118,700
All Electric Heat Pump with Hot Water	2	16	111	171	300	$ 383	$ 5,109	$ 1,532,700	$ 4,160	$ 1,248,000
Electric Hot Water Heater 50 Gal	0	16	63	69	148	$ 79	$ 1,056	$ 156,288	$ 860	$ 127,280
Air Conditioner Conversions	25	45	90	132	292	$ 89	$ 1,173	$ 342,516	$ -	$ -
Total	92	181	414	618	1305			$ 3,405,584		$ 2,493,980

Commercial

Equipment	2001 Units	2002 Units	2003 Units	2004 Units	Total Units	Estimated Revenue Per Unit	Justified Exp. Per Unit	Total JE to Date	JE Based upon PV Method	Total JE to Date Based on PV Method
Heat Pump	55	197	94	150	496	$ 50	$ 663	$ 328,848	$ 539	$ 267,344
Resistance Heat	0	0	0	0	0	$ 383	$ 5,109	$ -	$ 484	$ -
Apartments with Hot Water Heater	1	0	0	0	1	$ 45	$ 595	$ 595	$ 489	$ 489
Apartments without Hot Water Heater	0	0	0	0	0	$ 45	$ 598	$ -	$ 347	$ -
Apartment Hot Water Tanks	1	58	64	7	130	$ 14	$ 192	$ 24,960	$ 313	$ 40,690
Total					627			$ 354,403		$ 308,523

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Kansas City, Kansas Board of Public Utilities
Review of Heat Pump and Hot Water Heater Rebate Program

Table A - 6
Administrative Costs and Other Benefits

Year	Summer Capacity Reduction (kW)	Cumulative (kW)	Summer Capacity Rate ($/kW-mo)	Annual Capacity Savings *	Est. Annual Adm. Costs
2001	49	24.4	$ 1.85	$ 181	$ 124,715
2002	88	92.9	$ 1.85	$ 687	$ 241,504
2003	176	224.8	$ 2.25	$ 2,023	$ 332,319
2004	258	441.8	$ 4.00	$ 7,069	$ 328,386
Total	571			$ 9,961	$ 1,026,924

Kansas City, Kansas Board of Public Utilities
Volume VII - Integrated Resource Plan

Table A - 7
Residential Rebate Evaluation
Justified Expenditure Basis

Device	Est. Marginal Yearly KWH (Source Res. Market Mo. Report)	Marginal Rate	Est. Marginal Rev. (KWH @ Current Last Step of Rate)	Est. Marginal Expense	Estimated Marginal Net Revenue	Capitalized Value of Marginal Net Revenue per Unit
Add-On Heat Pump (AOHP)	8,291	$ 0.022	$ 182	$ -	$ 182	$ 2,432
All-Electric w HWH (AEHP w HWH)	17,418	$ 0.022	$ 383	$ -	$ 383	$ 5,109
All-Electric wo HWH (AEHP w HWH)	10,600	$ 0.022	$ 233	$ -	$ 233	$ 3,109
Electric Hot Water Heater (EHWH)	3,600	$ 0.022	$ 79	$ -	$ 79	$ 1,056
AC Conversions	4,000	$ 0.022	$ 88	$ -	$ 88	$ 1,173
Capitalization Rate (AA Rated 20 Yr. Mun Bonds.)	7.5%					

Kansas City, Kansas Board of Public Utilities
Volume VII - Integrated Resource Plan

Table A - 8
Residential Rebate Evaluation
Present Value Basis

	AOHP			AEHP/HWH			AEHP wo HWH			EHWT			AC CONVERSIONS		
Year	Marginal Net Revenue from AOHP	PV of Marginal Net Revenue	Cumulative PV of Marginal Net Revenue	Marginal Net Revenue from AEHP w HWH	PV Marginal Net Revenue of AEHP w HWH	Cumulative PV of Marginal Net Revenue	Marginal Net Revenue from AEHP wo HWH	PV Marginal Net Revenue of AEHP wo HWH	Cumulative PV of Marginal Net Revenue	Marginal Net Revenue from EHWT	PV Marginal Net Revenue of EHWT	Cumulative PV of Marginal Net Revenue	Marginal Net Revenue	PV Marginal Net Revenue of AEHP wo HWH	Cumulative PV of Marginal Net Revenue
0	$ 182	$ 182	$ 182	$ 383	$ 383	$ 383	$ 304	$ 304	$ 304	$ 79	$ 79	$ 79	$ 88	$ 88	$ 88
1	$ 182	$ 175	$ 357	$ 383	$ 368	$ 751	$ 304	$ 292	$ 596	$ 79	$ 76	$ 155	$ 88	$ 84	$ 172
2	$ 182	$ 168	$ 525	$ 383	$ 353	$ 1,104	$ 304	$ 280	$ 876	$ 79	$ 73	$ 228	$ 88	$ 81	$ 253
3	$ 182	$ 161	$ 687	$ 383	$ 339	$ 1,442	$ 304	$ 269	$ 1,144	$ 79	$ 70	$ 298	$ 88	$ 78	$ 331
4	$ 182	$ 155	$ 841	$ 383	$ 325	$ 1,767	$ 304	$ 258	$ 1,402	$ 79	$ 67	$ 365	$ 88	$ 75	$ 406
5	$ 182	$ 148	$ 990	$ 383	$ 312	$ 2,079	$ 304	$ 247	$ 1,649	$ 79	$ 64	$ 430	$ 88	$ 72	$ 477
6	$ 182	$ 142	$ 1,132	$ 383	$ 299	$ 2,378	$ 304	$ 237	$ 1,887	$ 79	$ 62	$ 492	$ 88	$ 69	$ 546
7	$ 182	$ 137	$ 1,269	$ 383	$ 287	$ 2,665	$ 304	$ 228	$ 2,115	$ 79	$ 59	$ 551	$ 88	$ 66	$ 612
8	$ 182	$ 131	$ 1,400	$ 383	$ 276	$ 2,941	$ 304	$ 219	$ 2,333	$ 79	$ 57	$ 608	$ 88	$ 63	$ 675
9	$ 182	$ 126	$ 1,526	$ 383	$ 264	$ 3,205	$ 304	$ 210	$ 2,543	$ 79	$ 55	$ 662	$ 88	$ 61	$ 736
10	$ 182	$ 121	$ 1,646	$ 383	$ 254	$ 3,459	$ 304	$ 201	$ 2,744	$ 79	$ 52	$ 715	$ 88	$ 58	$ 794
11	$ 182	$ 116	$ 1,762	$ 383	$ 243	$ 3,702	$ 304	$ 193	$ 2,937	$ 79	$ 50	$ 765	$ 88	$ 56	$ 850
12	$ 182	$ 111	$ 1,874	$ 383	$ 234	$ 3,936	$ 304	$ 185	$ 3,123	$ 79	$ 48	$ 814	$ 88	$ 54	$ 904
13	$ 182	$ 107	$ 1,980	$ 383	$ 224	$ 4,160	$ 304	$ 178	$ 3,300	$ 79	$ 46	$ 860	$ 88	$ 51	$ 955
Shared Benefits			$ 990			$ 2,080			$ 1,650			$ 430			$ 478
Pay Back Period			5.4			5.4			5.4			5.4			5.4
Discount Rate			4.21%												

Kansas City, Kansas Board of Public Utilities
Volume VII - Integrated Resource Plan

Table A - 9
Commercial Rebate Evaluation
Justified Expenditure Basis

Appliance	Est. Annual KWH	Marginal Rate	Est. Annual Net Revenue	Capitalized Value of Net Rev.
Add-On Heat Pump (AOHP)	6,210	$ 0.008	$ 50	$ 663
All-Electric w HWH (AEHP w HWH)	5,573	$ 0.008	$ 45	$ 595
Apts.- Heat Pumps w/EHWT	5,600	$ 0.008	$ 45	$ 598
Apts.- Heat Pumps wo/EHWT	4,000	$ 0.008	$ 32	$ 427
Apts.- EHWT	1,800	$ 0.008	$ 14	$ 192
Electric Hot Water Heater (EHWH) < 10 kW	3,600	$ 0.008	$ 29	$ 384
Electric Hot Water Heater (EHWH) > 10 kW	15,768	$ 0.008	$ 126	$ 1,683
Capitalization Rate (AA Rated 20 Yr. Mun Bonds.)	7.50%			

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	Add On Heat Pum			EHWT <10kW		
Year	Marginal Net Revenue from AOHP	PV of Marginal Net Revenue	Cumulative PV of arginal Net Revenue	Marginal Net Revenue from EHWT	PV Marginal Net Revenue of EHWT	Cumulative PV of Marginal Net Revenue
0	$ 50	$ 50	$ 29	$ 126	$ 126	$ 126
1	$ 50	$ 48	$ 78	$ 126	$ 121	$ 247
2	$ 50	$ 46	$ 126	$ 126	$ 116	$ 363
3	$ 50	$ 44	$ 172	$ 126	$ 111	$ 475
4	$ 50	$ 42	$ 216	$ 126	$ 107	$ 582
5	$ 50	$ 40	$ 258	$ 126	$ 103	$ 684
6	$ 50	$ 39	$ 298	$ 126	$ 98	$ 783
7	$ 50	$ 37	$ 337	$ 126	$ 95	$ 877
8	$ 50	$ 36	$ 374	$ 126	$ 91	$ 968
9	$ 50	$ 34	$ 410	$ 126	$ 87	$ 1,055
10	$ 50	$ 33	$ 444	$ 126	$ 84	$ 1,139
11	$ 50	$ 32	$ 477	$ 126	$ 80	$ 1,219
12	$ 50	$ 30	$ 509	$ 126	$ 77	$ 1,296
13	$ 50	$ 29	$ 539	$ 126	$ 74	$ 1,370
Discount Rate						

B

Kansas City, Kansas Board of Public Utilities
Volume VII – Integrated Resource Plan
Addendum to Electric System Master Plan – 2003

APPENDIX B

Street Light Replacement Data

Board of Public Utilities
Kansas City, Kansas

Appendix B
Table B - 1
Street Light Replacement Program Detail

			Multiple			Series				
Year	Type	Size Watts	Number Beginning of Year	Hours	kWh	Type	Size Watts	Number	Hours	kWh
2001	HPS	100	873	4307	376,004	MV	175	3456	4307.03	2,604,892
2001	HPS	150	-	4307	-	MV	250	607	4307.03	653,592
2001	HPS	250	4,724	4307	5,086,602	MV	400	911	4307.03	1,569,482
2001	HPS	400	206	4307	354,899	MV	1000	62	4307.03	267,036
2001	MV	175	6,074	4307	4,578,158					
2001	MV	250	1,107	4307	1,191,971					
2001	MV	400	1,482	4307	2,553,207					
2001	MV	1000	2,254	4307	9,708,046					
Total			16,720		23,848,887			5,036		5,095,001
Yearly Energy	28,943,888	Total Units	21,756							
kWh per Unit	1,330									
2002	HPS	100	898	4307	386,771	MV	175	3410	4307.03	2,570,220
2002	HPS	150	10	4307	6,461	MV	250	607	4307.03	653,592
2002	HPS	250	4918	4307	5,295,493	MV	400	911	4307.03	1,569,482
2002	HPS	400	206	4307	354,899	MV	1000	62	4307.03	267,036
2002	MV	175	6016	4307	4,534,441					
2002	MV	250	1105	4307	1,189,817					
2002	MV	400	1478	4307	2,546,316					
2002	MV	1000	2254	4307	9,708,046					
Total			16,885		24,022,244			4,990		5,060,330
Yearly Energy	29,082,574	Total Units	21,875							
kWh per Unit	1,329									
2003	HPS	100	933	4307	401,846	MV	175	3169	4307.03	2,388,571
2003	HPS	150	10	4307	6,461	MV	250	590	4307.03	635,287
2003	HPS	250	5163	4307	5,559,299	MV	400	911	4307.03	1,569,482
2003	HPS	400	206	4307	354,899	MV	1000	62	4307.03	267,036
2003	MV	175	6065	4307	4,571,374					
2003	MV	250	1122	4307	1,208,122					
2003	MV	400	1478	4307	2,546,316					
2003	MV	1000	2254	4307	9,708,046					
Total			17,231		24,356,362			4,732		4,860,376
Yearly Energy	29,216,738	Total Units	21,963							
kWh per Unit	1,330									
2004	HPS	100	954	4318.83	412,016	MV	175	2898	4307.03	2,184,310
2004	HPS	150	10	4318.83	6,478	MV	250	590	4307.03	635,287
2004	HPS	250	5746	4318.83	6,204,000	MV	400	911	4307.03	1,569,482
2004	HPS	400	206	4318.83	355,872	MV	1000	62	4307.03	267,036
2004	MV	175	6016	4318.83	4,546,865					
2004	MV	250	1126	4318.83	1,215,751					
2004	MV	400	1478	4318.83	2,553,293					
2004	MV	1000	2254	4318.83	9,734,645					
Total			17,790		25,028,920			4,461		4,656,115
Yearly Energy	29,685,035	Total Units	22,251							
kWh per Unit	1,334									
2005	HPS	100	1010	4307.03	435,010	MV	175	2663	4307.03	2,007,184
2005	HPS	150	10	4307.03	6,461	MV	250	590	4307.03	635,287
2005	HPS	250	5856	4307.03	6,305,492	MV	400	911	4307.03	1,569,482
2005	HPS	400	206	4307.03	354,899	MV	1000	62	4307.03	267,036
2005	MV	175	6244	4307.03	4,706,292					
2005	MV	250	1110	4307.03	1,195,201					
2005	MV	400	1478	4307.03	2,546,316					
2005	MV	1000	2254	4307.03	9,708,046					
Total			18,168		25,257,716			4,226		4,478,988
Yearly Energy	29,736,704	Total Units	22,394							
kWh per Unit	1,328									
Grand Total	146,664,939									

Lutz, Daily & Brain, LLC
Consulting Engineers

Board of Public Utilities
Kansas City, Kansas

Appendix B
Table B - 2
Street Light Replacement Program Summary

Type	Size Watts	2001 Number in Service	2002 Number in Service	2003 Number in Service	2004 Number in Service
HPS	100	873	898	933	954
HPS	150	-	10	10	10
HPS	250	4,724	4918	5163	5746
HPS	400	206	206	206	206
Total HPS		5,803	6,032	6,312	6,916
Total kWh		23,848,887	24,022,244	24,356,362	25,028,920
MV	175	9,530	9426	9234	8914
MV	250	1,714	1712	1712	1716
MV	400	2,393	2389	2389	2389
MV	1000	2,316	2316	2316	2316
Total MV		15,953	15,843	15,651	15,335
Total kWh		5,095,001	5,060,330	4,860,376	4,656,115
Grand Total kWh		28,943,888	29,082,574	29,216,738	29,685,035

C

Kansas City, Kansas Board of Public Utilities
Volume VII – Integrated Resource Plan
Addendum to Electric System Master Plan – 2003

APPENDIX C

Green Power Pricing by State

U.S. Department of Energy - Energy Efficiency and Renewable Energy
Green Power Network

Green Pricing

Utility Programs by State (33)

The table shown here summarizes utility green pricing programs by state. Please contact our Webmaster if you have more recent information regarding these or new green pricing programs.

Table of Green Pricing Programs
(as of April 2004)

State	Utility Name	Program Name	Type	Start Date	Premium
AL	Alabama Power Company	Renewable Energy Rate	biomass co-firing	2003 / 2000	6.0¢/kWh
AL	TVA: City of Athens, Cullman Electric Coop, Cullman Power Board, Florence, Hartselle, Huntsville, Joe Wheeler EMC, Muscle Shoals, Scottsboro, Sheffield, Tuscumbia	Green Power Switch	wind, landfill gas, solar	2000	2.67¢/kWh
AZ	Arizona Public Service	Solar Partners	central PV	1997	$2.64/15kWh
AZ	Salt River Project	EarthWise Energy	central PV, landfill gas, small hydro	1998/2001	3.0¢/kWh
AZ	Tucson Electric	GreenWatts	landfill gas, PV, wind	2000	7.5-10¢/kWh
CA	City of Alameda	Clean Future Fund	various, electric vehicles	1999	1.0¢/kWh
CA	Los Angeles Department of Water and Power	Green Power for a Green LA	wind, landfill gas	1999	3.0¢/kWh
CA	Palo Alto Utilities/3 Phases Energy Services	Palo Alto Green	wind, solar	2003 / 2000	1.5¢/kWh
CA	Pasadena Water & Power	Green Power	wind	2003	2.5¢/kWh
CA	Roseville Electric	RE Green Energy	geothermal, hydro, PV	2000	1.0¢/kWh
CA	Sacramento Municipal Utility District	Greenergy	wind, landfill gas, hydro	1997	1.0¢/kWh
CA	Sacramento Municipal Utility District	PV Pioneers I	PV	1993	$4/month
CO	Colorado Springs Utilities	Green Power	wind	1997	3.0¢/kWh
CO	Holy Cross Energy	Wind Power Pioneers	wind	1998	2.5¢/kWh
CO	Holy Cross Energy	Local Renewable Energy Pool	small hydro, PV	2002	3.3¢/kWh
CO	Platte River Power Authority: Estes Park, Fort Collins, Longmont, Loveland	Wind Power	wind	1996	2.5¢/kWh
CO	Tri-State Generation & Transmission: Carbon Power, Chimney Rock,Gunnison County	Renewable Resource Power Service	wind, landfill gas	1999	2.5¢/kWh

	Electric, K.C. Electric, La Plata Electric, Mountain Parks Electric, Mountain View Electric, New Mexico, Northwest Rural, Poudre Valley Rural Electric Association, Public Power District, San Isabel Electric, San Luis Valley Rural Electric Coop, San Miguel Power, Sangre, Springer Electric, United Power, White River (18 of 44 coops offer program)				
CO	Xcel Energy	Renewable Energy Trust	PV	1993	Contribution
CO	Xcel Energy	WindSource	wind	1997	2.5¢/kWh
CO	Yampa Valley Electric Association	Green Power	wind	1999	3.0¢/kWh
FL	City of Tallahassee/Sterling Planet	Green for You	biomass, solar	2002	1.6¢/kWh
FL	City of Tallahassee/Sterling Planet	Green for You	solar only	2002	11.6¢/kWh
FL	Florida Power & Light / Green Mountain Energy	Sunshine Energy	biomass, wind, solar	2004	0.975¢/kWh
FL	Gainesville Regional Utilities	GRUgreen Energy	landfill gas, wind, solar	2003	2.0¢/kWh
FL	Gulf Power Company	EarthCents Solar	PV in schools; central PV	1996/1999	Contribution; $6/100 watts
FL	Tampa Electric Company (TECO)	Tampa Electric's Renewable Energy Program	PV, landfill gas	2000	10.0¢/kWh
FL	Utilities Commission City of New Smyrna Beach	Green Fund	local PV projects	1999	Contribution
GA	Georgia Electric Membership Corporation (16 of 42 coops offer program): Carroll EMC, Coastal Electric, Cobb EMC, Coweta-Fayette EMC, Flint Energies, GreyStone Power, Habersham EMC, Irwin EMC, Jackson EMC, Jefferson Energy, Lamar EMC, Ocmulgee EMC, Sawnee EMC, Snapping Shoals EMC, Tri-County EMC, Walton EMC of Monroe	Green Power EMC	landfill gas	2001	TBD
GA	Georgia Power	Green Energy	landfill gas, wind, solar	2003	5.5¢/kWh
GA	Savannah Power	Green Energy	landfill gas, wind, solar	2003	6.0¢/kWh
GA	TVA: Blue Ridge Mountain Electric Membership Corporation, North Georgia Electric Membership Corporation	Green Power Switch	wind, landfill gas, solar	2000	2.67¢/ kWh
HI	Hawaiian Electric	Sun Power for Schools	PV in schools	1996	Contribution
ID	Avista Utilities	Buck-A-Block	wind	2002	1.8¢/kWh
ID	Idaho Power	Green Power Program	various	2001	Contribution
ID	PacifiCorp: Utah Power	Blue Sky	wind	2003	1.95¢/kWh
ID	Vigilante Electric Cooperative	Alternative Renewable	wind, solar, hydro	2003	1.1¢/kWh

		Energy Program			
IL	City of St. Charles/ComEd and Community Energy, Inc.	TBD	wind, landfill gas	2003	Contribution
IL	Dairyland Power Cooperative: Jo-Carroll Energy/Elizabeth	Evergreen Renewable Energy Program	wind	1997	3.0¢/kWh
IN	Hoosier Energy: Southeastern Indiana REMC, South Central Indiana REMC, Utilities District of Western Indiana REMC, Decatur County REMC, Daviess-Martin County REMC (5 of 17 coops offer program)	EnviroWatts	landfill gas	2001	2.0¢/kWh-4.0¢/kWh
IN	Indianapolis Power & Light	Elect Plan Green Power Program	geothermal	1998	0.9¢/kWh
IN	PSI Energy	Green Power Rider	wind, solar, landfill gas, digester gas	2001	Contribution
IN	Wabash Valley Power Association: Boone REMC, Hendricks Power Cooperative, Kankakee Valley REMC, Miami-Cass REMC, Tipmont REMC, White County REMC, Northeastern REMC (7 of 27 coops offer program)	EnviroWatts	landfill gas	2000	0.9¢/kWh-1.0¢/kWh
IA	Alliant Energy	Second Nature	landfill gas, wind	2001	2.0¢/kWh
IA	Basin Electric Power Cooperative: Lyon Rural, Harrison County, Nishnabotna Valley Cooperative, Northwest Rural Electric Cooperative, Western Iowa	Prairie Winds	wind	2000	1.0¢/kWh
IA	Cedar Falls Utilities	Wind Energy Electric Project	wind	1999	Contribution
IA	Corn Belt Power Cooperatives: (11 co-ops and 1 municipal cooperative) Boone Valley Electric Cooperative, Butler County REC, Calhoun County REC, Franklin REC, Glidden REC, Grundy County REC, Humboldt County REC, Iowa Lakes Electric Cooperative, Midland Power Cooperative, Prairie Energy Cooperative, Sac County REC, North Iowa Municipal Electric Cooperative Association	Varies by Utility	wind	2004	Contribution
IA	Dairyland Power Cooperative: Allamakee-Clayton/Postville, Hawkeye Tri-County/Cresco, Heartland Power/Thompson & St. Ansgar	Evergreen Renewable Energy Program	wind	1997	3.0¢/kWh
IA	Farmers Electric Cooperative	Green Power Project	biodiesel, wind	2004	Contribution
IA	Iowa Association of Municipal Utilities (80 of 137 participating) Afton, Algona, Alta Vista, Aplington, Auburn, Bancroft, Bellevue, Bloomfield, Breda, Brooklyn, Buffalo, Burt, Callender, Carlisle,	Green City Energy	wind, biomass, solar	2003	Varies by utility

	Cascade, Coggon, Coon Rapids, Corning, Corwith, Danville, Dayton, Durant, Dysart, Earlville, Eldridge, Ellsworth, Estherville, Fairbank, Farnhamville, Fontanelle, Forest City, Gowrie, Grafton, Grand Junction, Greenfield, Grundy Center, Guttenberg, Hopkinton, Hudson, Independence, Keosauqua, La Porte City, Lake Mills, Lake View, Laurens, Lenox, Livermore, Maquoketa, Marathon, McGregor, Milford, Montezuma, Mount Pleasant, Neola, New Hampton, Ogden, Orient, Osage, Panora, Pella, Pocahontas, Preston, Readlyn, Rockford, Sabula, Sergeant Bluff, Sibley, Spencer, Stanhope, State Center, Stratford, Strawberry Point, Stuart, Tipton, Villisca, Vinton, Webster City, West Bend, West Liberty, West Point, Westfield, Whittemore, Wilton, Winterset				
IA	MidAmerican Energy	Renewable Advantage	wind	2004	Contribution
IA	Missouri River Energy Services (MRES): Alton, Atlantic, Denison, Fontanelle, Hartley, Hawarden, Kimballton, Lake Park, Manilla, Orange City, Paullina, Primghar, Remsen, Rock Rapids, Sanborn, Shelby, Sioux Center, Woodbine	RiverWinds	wind	2003	2.0 - 2.5¢/kWh
IA	Muscatine Power and Water	Solar Muscatine	solar	2004	Contribution
IA	Waverly Light & Power	Iowa Energy Tags	wind	2001	2.0¢/kWh
KY	East Kentucky Power Cooperative: Blue Grass Energy, Clark, Cumberland, Fleming, Grayson, Inter-county Energy, Jackson, Licking, Mason, Nolin, Owen Electric, Salt River, Shelby, South Kentucky	EnviroWatts	landfill gas	2002	2.75¢/kWh
KY	TVA: Bowling Green Municipal Utilities, Franklin Electric Plant Board	Green Power Switch	wind, landfill gas, solar	2000	2.67¢/kWh
MA	Concord Municipal Light Plant (CMLP)	Green Power	hydro	2004	3.0¢/kWh
MI	Consumers Energy	Green Power Pilot Program	wind, various	2001	3.2¢/kWh
MI	Detroit Edison	Solar Currents	central PV	1996	$6.94/100 watts
MI	Lansing Board of Water and Light	GreenWise Electric Power	landfill gas, small hydro	2001	3.0¢/kWh
MI	Traverse City Light and Power	Green Rate	wind	1996	1.58¢/kWh
MI	We Energies	Energy for Tomorrow	wind, landfill gas, hydro	2000	2.04¢/kWh
MN	Alliant Energy	Second Nature	landfill gas, wind	2002	2.0¢/kWh

MN	Basin Electric Power Cooperative: Minnesota Valley Electric Coop, Sioux Valley Southwestern	Prairie Winds	wind	2000	1.0¢/kWh
MN	Dairyland Power Cooperative: Freeborn-Mower Cooperative / Albert Lea, People's / Rochester, Tri-County / Rushford	Evergreen Renewable Energy Program	wind	1997	3.0¢/kWh
MN	Great River Energy: Agralite, Arrowhead, BENCO Electric, Brown County Rural Electric, Connexus Energy, Co-op Light & Power, Crow Wing Power, Dakota Electric Association, East Central Electric Association, Federated Rural Electric, Goodhue County, Itasca Mantrap Cooperative, Kandiyohi Power Cooperative, Lake Country Power, Lake Region, McLeod Cooperative Power, Meeker Cooperative Light & Power, Mille Lacs, Minnesota Valley, Nobles Cooperative Electric, North Itasca, Redwood, Runestone Electric, South Central Electric Association , Stearns Electric, Steele-Waseca, Todd-Wadena , Wright-Hennepin Electric (all 29 coops offer program)	Wellspring Renewable Wind Energy Program	wind	1997	1.45¢/kWh-2.0¢/kWh
MN	Minnesota Power	WindSense	wind	2002	2.5¢/kWh
MN	Minnkota Power Cooperative: Beltrami, Clearwater Polk, North Star, PKM, Red Lake, Red River, Roseau, Wild Rice, Thief River Falls	Infinity Wind Energy	wind	1999	1.5¢/kWh
MN	Missouri River Energy Services: Adrian, Alexandria, Barnesville, Benson, Breckenridge, Detroit Lakes, Elbow Lake, Henning, Jackson, Lakefield, Lake Park, Luverne, Madison, Moorhead, Ortonville, St. James, Sauk Centre, Staples, Wadena, Westbrook, Worthington (39 of 55 munis offer program)	RiverWinds	wind	2002	2.0¢/kWh-2.5¢/kWh
MN	Moorhead Public Service	Capture the Wind	wind	1998	1.5¢/kWh
MN	Otter Tail Power Company	TailWinds	wind	2002	2.6¢/kWh
MN	Southern Minnesota Municipal Power Agency: Fairmont Public Utilities, Wells Public Utilities, Austin Utilities, Preston Public Utilities, Spring Valley Utilities, Blooming Prairie Public Utilities, Rochester Public Utilities, Owatonna Public Utilities, Waseca Utilities, St. Peter Municipal Utilities, Lake City Utilities, New Prague Utilities Commission, Redwood Falls Public Utilities, Litchfield Public Utilities, Princeton Public Utilities, North Branch Water and Light, Mora Municipal Utilities, Grand Marais Public Utilities (all 18	SMMPA Wind Power	wind	2000	1.0¢/kWh

	offer program)				
MN	Xcel Energy	WindSource	wind	2003	2.0¢/kWh
MS	TVA: City of Oxford, North East Mississippi Electric Power Asssociation, Starkville Electric System	Green Power Switch	wind, landfill gas, solar	2000	2.67¢/kWh
MO	Boone Electric Cooperative	Renewable Choice	wind	2003	2.0¢/kWh
MO	City Utilities of Springfield	WindCurrent	wind	2000	5.0¢/kWh
MT	Basin Electric Power Cooperative: Lower Yellowstone	Prairie Winds	wind	2000	1.0¢/kWh
MT	Northwestern Energy	E+ Green	wind, solar	2003	2.0¢/kWh
MT	Vigilante Electric Cooperative	Alternative Renewable Energy	wind, hydro, solar	2003	1.1¢/kWh
NE	Lincoln Electric System	LES Renewable Energy Program	wind	1998	4.3¢/kWh
NE	Omaha Public Power District	Green Power Program	landfill gas, wind	2002	3.0¢/kWh
NE	Tri-State: Chimney Rock Public Power District, Northwest Rural Public Power District	Renewable Resource Power Service	wind, landfill gas	2001	2.5¢/kWh
NM	El Paso Electric	Renewable Energy Tariff	wind	2003	3.19¢/kWh
NM	Public Service of New Mexico	PNM Sky Blue	wind	2003	1.8¢/kWh
NM	Tri-State: Kit Carson Electric Cooperative	Renewable Resource Power Service	wind, landfill gas	2001	2.5¢/kWh
NM	Xcel Energy	WindSource	wind	1999	3.0¢/kWh
NC	Dominion North Carolina Power	NC GreenPower	biomass, wind, solar	2003	4.0¢/kWh
NC	Duke Power	NC GreenPower	biomass, wind, solar	2003	4.0¢/kWh
NC	ElectriCities: City of High Point, City of Laurinburg, City of Newton, City of Shelby, City of Statesville, town of Apex, Town of Granite Falls	NC GreenPower	biomass, wind, solar	2003	4.0¢/kWh
NC	NC Electric Cooperatives (14 of 27 cooperatives offer the program): Blue Ridge Electric Membership Corp., Brunswick Electric Membership Corp., Carteret Craven Electric Coop., Edgecombe-Martin County Electric Membership Corp., EnergyUnited, Four County Electric Membership Corp., Haywood Electric Membership Corp., Jones-Onslow Electric Membership Corp., Pee Dee Electric Membership Corp., Piedmont Electric Membership Corp., Randolph Electric Membership Corp., Roanoke Electric Membership Corp., Tri-County Electric Membership Corp., Wake Electric Membership Corp.	NC GreenPower	biomass, wind, solar	2003	4.0¢/kWh
NC	Progress Energy / CP&L	NC GreenPower	biomass, wind, solar	2003	4.0¢/kWh

NC	TVA: Mountain Electric Cooperative	Green Power Switch	landfill gas, solar, wind	2000	2.67¢/kWh
ND	Basin Electric Power Cooperative: Oliver Mercer Electric Coop, Mor-gran-sou Electric Coop, KEM Electric Coop, North Central Electric Coop, Verendrye, Capital , Northern Plains, Dakota Valley, Burke Divide, Montrail Williams, McKenzie Electric Coop, West Plains, Slope Electric Coop (49 coops offer program in 5 states)	PrairieWinds	wind	2000	1.0¢/kWh
ND	Minnkota Power Cooperative: Cass County Electric, Cavalier Rural Electric, Nodak Electric, Northern Municipal Power Agency (12 municipals)	Infinity Wind Energy	wind	1999	1.5¢/kWh
ND	Missouri River Energy Services: City of Lakota	RiverWinds	wind	2002	2.0 - 2.5¢/kWh
OH	American Municipal Power-Ohio / Green Mountain Energy: Cuyahoga Falls	Nature's Energy	landfill gas, wind, small hydro	2003	1.3¢/kWh
OH	City of Bowling Green	Bowling Green Power	small hydro, wind, landfill gas	1999	1.35¢/kWh
OK	Edmond Electric	Pure & Simple	wind	2004	1.8¢/kWh
OK	OG&E Electric Services	Wind Power	wind	2003	0.63¢/kWh
OR	City of Ashland/Bonneville Environmental Foundation	Renewable Pioneers	solar	2003	2.0¢/kWh
OR	Emerald People's Utility District/Green Mountain Energy	Choose Renewable Electricity	wind, geothermal	2003	0.78-1.2¢/kWh
OR	Eugene Water & Electric Board	EWEB Wind Power	wind	1999	1.3¢/kWh
OR	Midstate Electric Cooperative	Environmentally-Preferred Power	wind, small hydro	1999	2.5¢/kWh
OR	Oregon Trail Electric Cooperative	Green Power	wind	2002	1.5¢/kWh
OR	PacifiCorp: Pacific Power	Blue Sky Block	wind	2000	1.95¢/kWh
OR	PacifiCorp: Pacific Power / 3 Phases Energy Services	Blue Sky Usage	existing geothermal, wind	2002	0.78¢/kWh
OR	PacifiCorp: Pacific Power / 3 Phases Energy Services	Blue Sky Habitat	existing geothermal, wind	2002	0.78¢/kWh + $2.50 donation
OR	Pacific Northwest Generating Cooperative: Central Electric Cooperative, Clearwater Power, Consumers Power, Douglas Electric Cooperative, Umatilla Electric Cooperative (5 of 16 coops offer program)	Green Power	landfill gas	1998	1.8¢/kWh-2.0¢/kWh
OR	Portland General Electric / Green Mountain Energy	Green Mountain Renewable Energy Usage	existing geothermal, wind	2002	0.8¢/kWh
OR	Portland General Electric / Green Mountain Energy	Healthy Habitat	existing geothermal, wind	2002	0.99¢/kWh

OR	Portland General Electric Company	Clean Wind Power	wind	2000	3.5¢/kWh
OR	Portland General Electric Company	Clean Wind for Medium to Large Commercial & Industrial Accounts	wind	2003	1.5 - 1.7¢/kWh
SC	Santee Cooper, Aiken Electric Cooperative, Berkeley Electric Cooperative, Horry Electric Cooperative, Laurens Electric Cooperative, Marlboro Electric Cooperative, Mid-Carolina Electric Cooperative, Palmetto Electric Cooperative, Santee Electric Cooperative, Tri-County Electric Cooperative, York Electric Cooperative	Green Power Program	landfill gas	2001	3.0¢/kWh
SD	Basin Electric Power Cooperative: Bon Homme-Yankton Electric Assn., Central Electric Cooperative Association, Charles Mix Electric Association, City of Elk Point, Clay-Union Electric Corporation, Codington-Clark Electric Cooperative, Dakota Energy Cooperative, Douglas Electric Cooperative, FEM Electric Association, H-D Electric Cooperative, Kingsbury Electric Cooperative, Lyon-Lincoln Electric Cooperative, McCook Electric Cooperative, Northern Electric Cooperative, Oahe Electric Cooperative, Renville-Sibley Coop. Power Assn., Sioux Valley Southwestern Electric Coop, Southeastern Electric Coop, Union County Electric Cooperative, Whetstone Valley Electric Cooperative, Black Hills Electric Coop, LaCreek Electric Coop, West River Power Association, Butte Electric Coop, Cherry Todd Electric Coop, Moreau Grand, Grand Electric Cooperative, Rosebud	Prairie Winds	wind	2000	1.0¢/kWh
SD	Missouri River Energy Services: City of Vermillion	RiverWinds	wind	2002	2.0 - 2.5¢/kWh
TN	TVA: Appalachian Electric Coop, Athens Utility Board, Bristol Tennessee, Caney Fork Electric Coop, Clarksville, Cleveland Utilities, Clinton, Cookeville, Cumberland EMC, Dickson Electric Department, Duck River EMC, Elizabethton, EPB (Chattanooga), Erwin, Fayetteville Public Utilities, Gibson Electric, Greeneville, Harriman Utility, Johnson City Power Board, Jackson, Knoxville, Lafollette, Lawrenceburg, Lenoir, Loudon Utilities, City of Maryville Electric Department, McMinnville,	Green Power Switch	biogas, solar, wind	2000	2.67¢/kWh

	Meriwhether Lewis Electric, Middle Tennessee EMC, Morristown, Mountain Electric Coop, Murfreesboro, Nashville, Newport, Oak Ridge, Paris BPU, Plateau Electric, Powell Valley Electric Coop, Pulaski, Sequachee Valley Electric, Sevier County, Springfield Dept. of Elect., Sweetwater Utilities, Tullahoma, Upper Cumberland Elect., Volunteer Energy Corp.				
TX	Austin Energy (City of Austin)	GreenChoice	wind, landfill gas and hydro	2000/1997	0.5¢/kWh
TX	City Public Service of San Antonio	Windtricity	wind	2000	3.0¢/kWh
TX	El Paso Electric Company	Renewable Energy Tariff	wind	2001	1.92¢/kWh
UT	Pacificorp: Utah Power	Blue Sky	wind	2000	1.95¢/kWh
VT	Central Vermont Public Service	CVPS Cow Power	biogas	TBD	4.0¢/kWh
VT	Green Mountain Power	CoolHome / CoolBusiness	wind, biogas	2002	Contribution
WA	Avista Utilities	Buck-A-Block	wind	2002	1.82¢/kWh
WA	Benton County Public Utility District	Green Power Program	landfill gas, wind	1999	Contribution
WA	Chelan County PUD	Sustainable Natural Alternative Power (SNAP)	PV, wind, micro hydro	2001	Contribution
WA	Clallam County PUD	Green Power Rate	landfill gas	2001	0.7¢/kWh
WA	Clark Public Utilities	Green Lights	PV, wind	2002	1.5¢/kWh
WA	Cowlitz PUD	Renewable Resource Energy	wind, PV	2002	2.0¢/kWh
WA	Grant County PUD	Alternative Energy Resources Program	wind	2002	2.0¢/kWh
WA	Grays Harbor PUD	Green Power	wind	2002	3.0¢/kWh
WA	Lewis County PUD	Green Power Energy Rate	wind	2003	2.0¢/kWh
WA	Mason County PUD No. 3	Mason Evergreen Power	wind	2003	2.0¢/kWh
WA	Orcas Power & Light	Go Green	wind, small hydro, PV	1997	3.5¢/kWh
WA	Pacific County PUD	Green Power	wind, hydro	2002	1.05¢/kWh
WA	Pacificorp: Pacific Power	Blue Sky	wind	2000	1.95¢/kWh
WA	Peninsula Light	Green by Choice	wind, hydro	2002	2.8¢/kWh
WA	Puget Sound Energy	Green Power Plan	wind, solar	2002	2.0¢/kWh
WA	Seattle City Light	Seattle Green Power	solar, wind, biogas	2002	Contribution
WA	Snohomish County Public Utility District	Planet Power	wind	2002	2.0¢/kWh
WA	Tacoma Power	EverGreen Options	small hydro, wind	2000	Contribution
WI	Alliant Energy	Second Nature	wind,	2000	2.0¢/kWh

			landfill gas		
WI	Dairyland Power Cooperative: Barron Electric, Bayfield/ Iron River, Chippewa / Cornell Valley, Clark / Greenwood, Dunn / Menomonie, Eau Claire / Fall Creek, Jackson / Black River Falls, Jump River / Ladysmith, Oakdale, Pierce-Pepin / Ellsworth, Polk-Burnett / Centuria, Price / Phillips, Richland, Riverland / Arcadia, St. Croix / Baldwin, Scenic Rivers / Lancaster, Taylor / Medford, Vernon / Westby	Evergreen Renewable Energy Program	wind	1997	3.0¢/kWh
WI	Great River Energy: Head of the Lakes	Wellspring Renewable Wind Energy Program	wind	1997	1.28¢/kWh-2.0¢/kWh
WI	Madison Gas & Electric	Wind Power Program	wind	1999	3.3¢/kWh
WI	We Energies	Energy for Tomorrow	landfill gas, hydro, wind	1996	2.04¢/kWh
WI	Wisconsin Public Power Inc.: Algoma, Cedarburg, Florence, Kaukauna, Muscoda, Stoughton, Reedsburg, Oconomowoc, Waterloo, Whitehall, Columbus, Hartford, Lake Mills, New Holstein, Richland Center, Boscobel, Cuba City, Hustisford, Sturgeon Bay, Waunakee, Lodi, New London, Plymouth, River Falls, Sun Prairie, Waupun, Eagle River, Jefferson, Menasha, New Richmond, Prairie du Sac, Slinger, Two Rivers, Westby (34 of 37 munis offer program)	Renewable Energy Program	small hydro, wind, biogas	2001	2.0¢/kWh
WI	Wisconsin Public Service	NatureWise	wind, landfill gas, biogas	2002	2.65¢/kWh
WI	Wisconsin Public Service	Solar Wise for Schools	PV in schools	1997	Contribution
WY	Lower Valley Energy	Green Power	wind	2003	1.67¢/kWh
WY	Pacificorp: Pacific Power	Blue Sky	wind	2000	1.95¢/kWh
WY	Tri-State: Carbon Power & Light	Renewable Resource Power Service	wind, landfill gas	2001	2.5¢/kWh

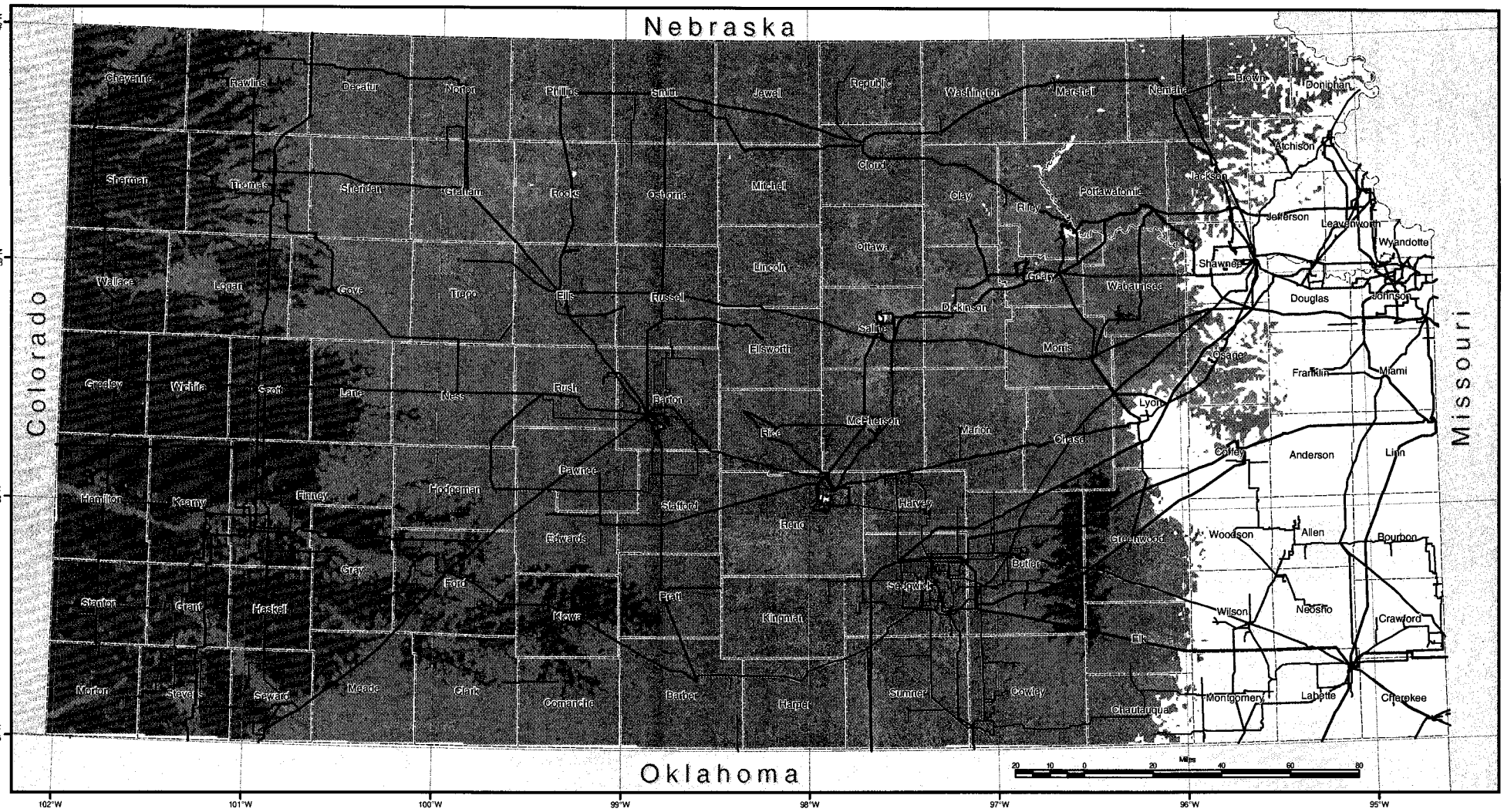
Source: National Renewable Energy Laboratory, Golden, Colorado.

D

Kansas City, Kansas Board of Public Utilities
Volume VII – Integrated Resource Plan
Addendum to Electric System Master Plan – 2003

Appendix D

Kansas Wind Map



Electric Transmission Lines	Wind Speed at 50 meters (m/s)	(mph)	Wind Power Density at 50m W/m²
345 - KV	Class 1: 0.00 - 5.60	0.00 - 12.5	0 - 200
230 - KV	Class 2: 5.60 - 6.40	12.5 - 14.3	200 - 300
161 - KV	Class 3: 6.40 - 7.00	14.3 - 15.7	300 - 400
138 - KV	Class 4: 7.00 - 7.50	15.7 - 16.8	400 - 500
115 - KV	Class 5: 7.50 - 8.00	16.8 - 17.9	500 - 600
69 - KV	Class 6: 8.00 - 8.80	17.9 - 19.7	600 - 700
	Class 7: > 8.80	> 19.7	> 700

Kansas Wind Resource Map

Coriolis architecture + energy

N W E S

Kansas Corporation Commission Energy Programs

The wind resource estimates presented on this map were developed by Coriolis-AE using WindMap TM, a program developed by BrowerCo. WindMap TM is a mass conserving model based on NOABL, a program developed in the 1970s by the U. S. Department of Energy. The spatial grid resolution is of 1000 (app) meters.

The resource estimates have NOT been validated by the National Renewable Energy Laboratory (NREL) or independent meteorologist. All wind energy development projects should confirm wind resources by direct measurements in accordance with wind energy industry standards.

Development of this map was performed under contract with the Kansas Corporation Commission Energy Program with funding from the U. S. Department of Energy's Wind Power America Program.

This map may be viewed on the web at: http://www.kcc.state.ks.us/energy/wind.htm

Kansas Corporation Commission
26 March 2004

E

Kansas City, Kansas Board of Public Utilities
Volume VII – Integrated Resource Plan
Addendum to Electric System Master Plan – 2003

Appendix E

Action Plan Implementation Schedule

Kansas CIty, Kansas, Board of Public Utilities
Volume VII - Integrated Resource Plan

Appendix E
Chart 1
Action Plan and Implementation Schedule