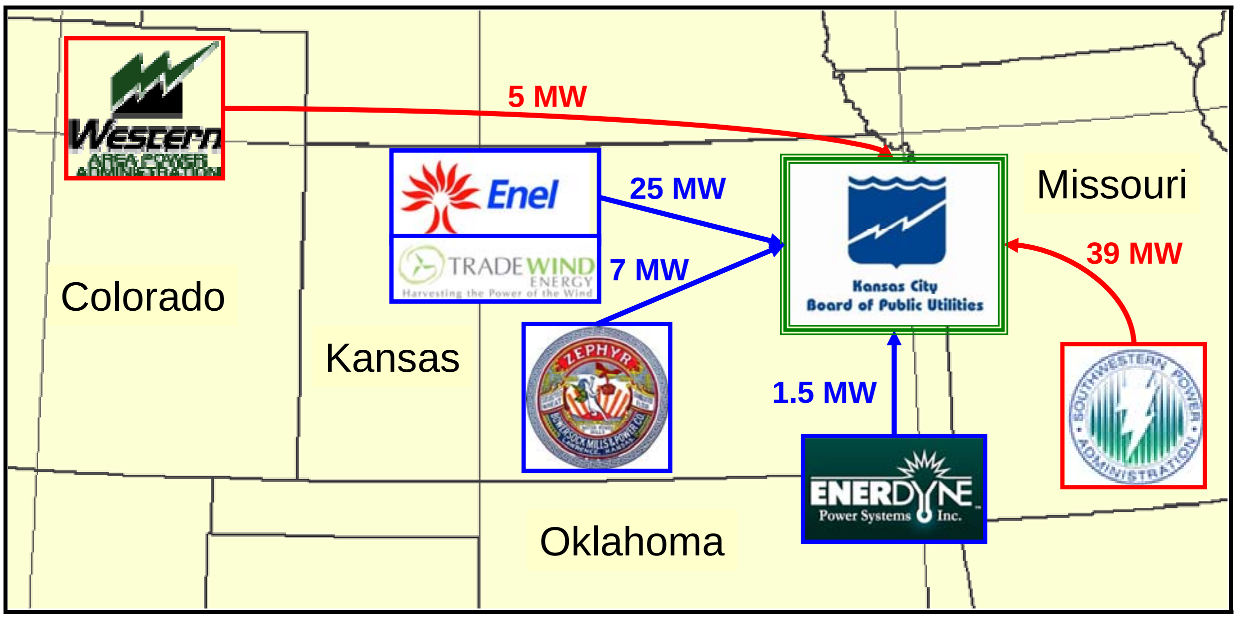
INTEGRATED RESOURCE PLAN

Prepared and submitted to meet WAPA IRP filing requirements of October 2009

Rev. 20110531



BPU Long–term Renewable Energy Contracts

by the

BOARD OF PUBLIC UTILITIES

KANSAS CITY, KANSAS

5172

RESOLUTION No. ~~5164~~

RESOLUTION APPROVING OCTOBER 2009 INTEGRATED RESOURCE PLAN OF THE BOARD OF PUBLIC UTILITIES PERTAINING TO PLANNING FOR NEW ENERGY SOURCES

WHEREAS, the Board of Public Utilities (the "BPU") of the Unified Government of Wyandotte County/Kansas City ("Unified Government"), has prepared a 2009 Integrated Resource Plan in accordance with Department of Energy Regulations at 10 CFR Part 905, Subpart B for submittal to the Western Area Power Administration in accordance with the regulations; and

WHEREAS, the BPU reviewed the 2009 Integrated Resource Plan at its regular meeting on. April 6, 2011; and

WHEREAS, the BPU has reviewed progress related to the action items relevant to approval and included in the 2009 Integrated Resource Plan since October 2009 and has reviewed the May 2011 Supplement to the 2009 Integrated Resource Plan; and

WHEREAS, the BPU has considered all matters it deemed necessary or appropriate to enable it to review, evaluate and reach an informed conclusion as to completeness and approval of the 2009 Integrated Resource Plan as supplemented and has determined that the 2009 Integrated Resource Plan as supplemented is complete to and in the best interests of the BPU.

BE IT RESOLVED BY THE KANSAS CITY BOARD OF PUBLIC UTILITIES AS FOLLOWS:

1. The 2009 Integrated Resource Plan as supplemented is determined complete and is approved for submittal to the Western Area Power Administration pursuant to Department of Energy Regulations at 10 CFR Part 905, Subpart B, and provides for the overall direction of activities related to providing adequate and reliable electric service; and further

2. Don L. Gray, General Manager of the BPU, and Darrell Dorsey as Manager of Electric Supply and Production of the BPU are authorized and directed to execute such planning activities as are necessary to provide reliable electric energy supply consistent with the 2009 Integrated Resource Plan as supplemented.

Passed by the Kansas City Board of Public Utilities this May 18, 2011.

President – Board of Public Utilities

ATTEST:

Mary Gonzales

Secretary – Board of Public Utilities

Approved as to Form:

Jody Boeding

Office of Chief Counsel – Unified Government
Of Wyandotte County/Kansas City, Kansas

DB03/504745.0013/9666518.1 CR06

KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
INTEGRATED RESOURCE PLAN
2009

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I. INTRODUCTION

Integrated resource planning is a process that considers demand-side options in addition to traditional supply-side options to meet the electric power needs of an electrical system. Integrated resource planning focuses on seeking and evaluating opportunities for demand and energy savings in addition to evaluating traditional supply resources. It is an on-going and evolutionary process calling for a reanalysis of utility system plans as conditions, prices, costs, technologies, and power requirements change. The integrated resource planning process anticipates the future and considers the many uncertainties a utility faces. An objective of integrated resource planning is to find a lowest cost solution that supplies customers the amount and quality of electric service desired while at the same time supports the utility's long term financial health. Solid, long-term integrated resource planning takes into account price elasticity of demand, reliability, and quality of service.

Under an agreement with WAPA, the Board of Public Utilities of Kansas City, Kansas (BPU) is required by law to file an Integrated Resource Plan (IRP) with the Western Area Power Administration (WAPA), an Agency of the U.S. Department of Energy, and update the plan every five years. The BPU is also required to submit annual progress reports on the status of its IRP. In return, the BPU 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. This document is the BPU's 2009 Integrated Resource Plan report and documents the integrated resource planning the BPU currently has in place.

II. BENEFITS OF IRP PLANNING

There are multiple benefits which can be derived from integrated resource planning. A good practical plan manages risks and seeks to minimize long-run costs. It also encourages energy conservation and the use of renewable energy resources and promotes the use of lower cost and more abundant fuels. Furthermore, 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 marginal revenues, and to reduce costs. Some of these benefits to the BPU have been that it has:

1. Deferred new generation capacity additions. 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 off peak energy uses.
5. Assisted in improving public relations.
6. Aided in energy conservation.

Such planning benefits all customers and helps to minimize the need for rate increases. To achieve these benefits the BPU applies significant resources to these activities. For instance in 2008 BPU allocated over $407,000 for demand-resource applications and had nearly $3,800,000 in renewable resource expenditures. The 2009 Budget for Energy Efficiency and Demand Response Programs is almost $700,000.

III. BPU ELECTRIC UTILITY OVERVIEW

The Kansas City Board of Public Utilities (BPU) was established in 1929 to provide the highest quality electric and water services at the lowest possible cost. Currently the BPU serves approximately 65,000 electric and 51,000 water customers. BPU's mission is to be the utility of choice and the workplace of choice, while improving the quality of life in the communities it serves. BPU is a publicly owned administrative agency of the Unified Government of Wyandotte County/Kansas City, Kansas, and is self-governed by an elected six-member board of directors. The Utility serves 127.5 square miles of Wyandotte County. Electric services are provided within Kansas City, Kansas (KCK) and Wyandotte County.

The electric utility was established in late 1912. Current facilities consist of three power stations, 29 substations and 2,992 miles of electrical lines. The three power stations contain generators with the following approximate capacities:

- Nearman Creek Power Station – capacity 307 MW
- Quindaro Power Station – capacity 304 MW
- Kaw Power Station – capacity 98 MW (currently cold standby)

Transmission systems consist of 161 kV and 69 kV transmission lines. The 161 kV system is configured in two loops, establishing a "figure eight" over the entire service territory. Interconnection between the 161 kV and 69 kV systems is made at four locations. Highest peak demand was recorded on August 9, 2006, at 529 MW. Electrical lines interconnect to four Kansas City Power & Light locations and one Westar Energy location.

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. WAPA provided the initial exposure of integrated resource planning to the BPU, and from the beginning WAPA staff has provided invaluable assistance in implementing this program. This planning process continues today. As conditions and technologies change, existing programs are modified and new studies are performed and incorporated into updates of BPU electric 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 that focus on demand-side opportunities. For example, there was an in-depth demand-side market assessment completed in May 1993 and an evaluation of generation powered by landfill gas in June 2003. An update of the plan was due in 2004 and submitted in 2005 with annual reports provided to WAPA for the interim years with the last annual report submitted for the year 2009. This IRP update contains discussion of past and current activities, along with a discussion of plans for the future.

IV. LOAD ANALYSIS & FORECAST

The Board of Public Utilities updates its electric load forecast on an ongoing basis. Short–term peak demand energy forecasts are developed for use in revenue forecasting and budgeting. Long–term energy and peak demand forecasts are developed for use in longer term system planning such as to assess the long-term energy and demand requirements of the BPU and for use in performing analyses of various capacity and/or energy purchase options.

A. Methodology

BPU’s forecasting method is a bottom-up approach developed by aggregating customer class specific forecasts. Developing customer class specific forecasts allows for the ability to get a refined estimate of total system demand. The estimates for the individual customer classes are aggregated to develop the estimate for the entire system as a whole. In using this method, the forecast for the system as a whole is typically more accurate since it allows for careful consideration of the change in demand for each of the customer classes and then combining these carefully considered estimates rather than merely making one large system forecast estimate which may not as thoroughly consider all of the factors causing both the change in number of customers in each class and the use per customer of each individual customer class.

Customer class-specific forecast models of the energy requirements are developed utilizing forecasting software. Individual energy sales forecast models were prepared for each of the three largest customer classes, which are industrial, commercial, and residential, using the Smart Forecast software. The forecast models are based on historical and projected future customer class–specific energy requirements. The historical data for the years 1989 through 2009 were used. The twenty years forecasted are 2010 through 2029. Below are graphs and output of the industrial, commercial, and residential class data. No future major industrial customers have been added beyond the existing known customers.

B. Major Customer Class Historical and Forecast Demand

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are aggregated in the table below:

Table 1
Historical and Forecast Annual Major Customer Class Data (MWh)

Year	INDUSTRIAL	Percent Change	COMMERICAL	Percent Change	RESIDENTIAL	Percent Change	Customer Classes Summed	Percent Change
1994	*736,222*		*749,647*		*490,565*		*1,976,434*	
1995	*742,405*		*766,786*		*505,071*		*2,014,262*	
1996	*776,176*		*775,978*		*498,538*		*2,050,692*	
1997	*798,688*		*800,422*		*511,299*		*2,110,409*	
1998	*803,312*		*820,089*		*543,913*		*2,167,314*	
1999	*857,643*		*821,146*		*512,422*		*2,191,211*	
2000	*803,137*		*822,627*		*545,308*		*2,171,072*	
2001	*817,759*		*802,679*		*550,869*		*2,171,307*	
2002	*822,336*		*802,521*		*568,701*		*2,193,558*	
2003	*814,756*		*791,141*		*525,369*		*2,131,266*	
2004	*900,749*		*856,716*		*528,738*		*2,286,203*	
2005	*889,595*		*856,388*		*564,945*		*2,310,928*	
2006	*869,656*		*909,405*		*564,353*		*2,343,414*	
2007	*774,212*		*909,220*		*574,127*		*2,257,559*	
2008	*733,053*		*877,656*		*550,774*		*2,161,483*	
2009	*678,327*		*843,232*		*535,690*		*2,057,249*	
2010	691,383	1.9%	884,401	4.9%	540,063	0.8%	2,115,847	2.85%
2011	693,870	0.4%	897,067	1.4%	544,471	0.8%	2,135,408	0.92%
2012	696,357	0.4%	910,180	1.5%	548,893	0.8%	2,155,430	0.94%
2013	698,844	0.4%	912,980	0.3%	553,316	0.8%	2,165,140	0.45%
2014	701,331	0.4%	923,404	1.1%	557,752	0.8%	2,182,487	0.80%
2015	703,818	0.4%	934,275	1.2%	562,194	0.8%	2,200,287	0.82%
2016	706,305	0.4%	937,075	0.3%	566,636	0.8%	2,210,016	0.44%
2017	708,792	0.4%	939,876	0.3%	571,089	0.8%	2,219,757	0.44%
2018	711,279	0.4%	942,676	0.3%	575,541	0.8%	2,229,496	0.44%
2019	713,766	0.3%	945,477	0.3%	580,003	0.8%	2,239,246	0.44%
2020	716,253	0.3%	948,277	0.3%	584,464	0.8%	2,248,994	0.44%
2021	718,740	0.3%	951,077	0.3%	588,933	0.8%	2,258,750	0.43%
2022	721,227	0.3%	953,877	0.3%	593,406	0.8%	2,268,510	0.43%
2023	723,714	0.3%	956,678	0.3%	597,877	0.8%	2,278,269	0.43%
2024	726,201	0.3%	959,478	0.3%	602,356	0.7%	2,288,035	0.43%
2025	728,688	0.3%	962,279	0.3%	606,833	0.7%	2,297,800	0.43%
2026	731,175	0.3%	965,079	0.3%	611,317	0.7%	2,307,571	0.43%
2027	733,662	0.3%	967,879	0.3%	615,798	0.7%	2,317,339	0.42%
2028	736,149	0.3%	970,680	0.3%	620,287	0.7%	2,327,116	0.42%
2029	738,636	0.3%	973,480	0.3%	624,778	0.7%	2,336,894	0.42%

The major customer classes' aggregate number is added to the smaller customer classes' energy forecasts. The smaller customer classes are: schools, local government, highway lighting, and metered and un-metered city government, BPU interdepartmental and borderline customers. Borderline customers' demand is served by BPU through a neighboring utility's distribution system. The customers are billed through the neighboring utility's billing system and BPU is paid by the neighboring utility. The table of historical and forecasted data of the small customer class data appears on the next page.

Table 2
Smaller Customer Class Data

MW-h

Year	SCHOOLS	HIGHWAY LIGHTING	COUNTY	Metered City of KCK	Unmetered City of KCK	BPU Inter-department	Borderline	Total
1996							*13,893*	
1997							*14,967*	
1998	*53,842*	*3,380*	*9,247*	*34,986*			*15,525*	
1999	*51,810*	*2,972*	*8,911*	*35,355*			*13,926*	
2000	*55,483*	*2,962*	*9,380*	*38,029*	*34,930*	*29,600*	*16,875*	*187,258*
2001	*60,838*	*2,969*	*9,901*	*35,290*	*34,960*	*33,240*	*16,882*	*194,080*
2002	*63,612*	*2,973*	*7,872*	*34,794*	*35,181*	*41,911*	*18,221*	*204,565*
2003	*69,516*	*3,072*	*8,621*	*35,052*	*35,663*	*31,387*	*17,338*	*200,651*
2004	*68,938*	*2,666*	*8,438*	*33,678*	*36,042*	*46,563*	*17,806*	*214,130*
2005	*68,272*	*2,666*	*8,757*	*33,407*	*44,998*	*47,627*	*18,766*	*224,492*
2006	*70,867*	*2,666*	*8,782*	*34,428*	*36,783*	*44,613*	*18,679*	*216,818*
2007	*75,578*	*2,664*	*8,663*	*30,523*	*38,716*	*44,984*	*19,314*	*220,442*
2008	*75,240*	*2,646*	*7,864*	*36,320*	*37,425*	*45,882*	*18,483*	*223,860*
2009	*78,382*	*2,345*	*7,637*	*33,104*	*37,434*	*35,386*	*18,430*	*212,717*
2010	80,987	2,552	8,055	33,322	37,864	42,090	18,742	223,612
2011	83,251	2,552	8,055	33,322	37,864	42,511	18,883	226,438
2012	85,516	2,552	8,055	33,322	37,864	42,936	19,024	229,269
2013	87,781	2,552	8,055	33,322	37,864	43,366	19,167	232,106
2014	90,045	2,552	8,055	33,322	37,864	43,799	19,311	234,948
2015	92,310	2,552	8,055	33,322	37,864	44,237	19,456	237,795
2016	94,575	2,552	8,055	33,322	37,864	44,680	19,602	240,648
2017	96,839	2,552	8,055	33,322	37,864	45,126	19,749	243,507
2018	99,104	2,552	8,055	33,322	37,864	45,578	19,897	246,371
2019	101,369	2,552	8,055	33,322	37,864	46,033	20,046	249,241
2020	103,633	2,552	8,055	33,322	37,864	46,494	20,196	252,116
2021	105,898	2,552	8,055	33,322	37,864	46,959	20,348	254,997
2022	108,163	2,552	8,055	33,322	37,864	47,428	20,500	257,884
2023	110,428	2,552	8,055	33,322	37,864	47,903	20,654	260,777
2024	112,692	2,552	8,055	33,322	37,864	48,382	20,809	263,675
2025	114,957	2,552	8,055	33,322	37,864	48,865	20,965	266,580
2026	117,222	2,552	8,055	33,322	37,864	49,354	21,122	269,491
2027	119,486	2,552	8,055	33,322	37,864	49,848	21,281	272,407
2028	121,751	2,552	8,055	33,322	37,864	50,346	21,440	275,330
2029	124,016	2,552	8,055	33,322	37,864	50,850	21,601	278,259

The aggregated system net is compared to monthly historical system net to allow for some weather normalization smoothing effect.

C. Losses

Losses are estimated based on component losses for transmission, primary, and secondary loads. These loss estimates are applied by customer class as annotated below.

Table 3
LOSSES

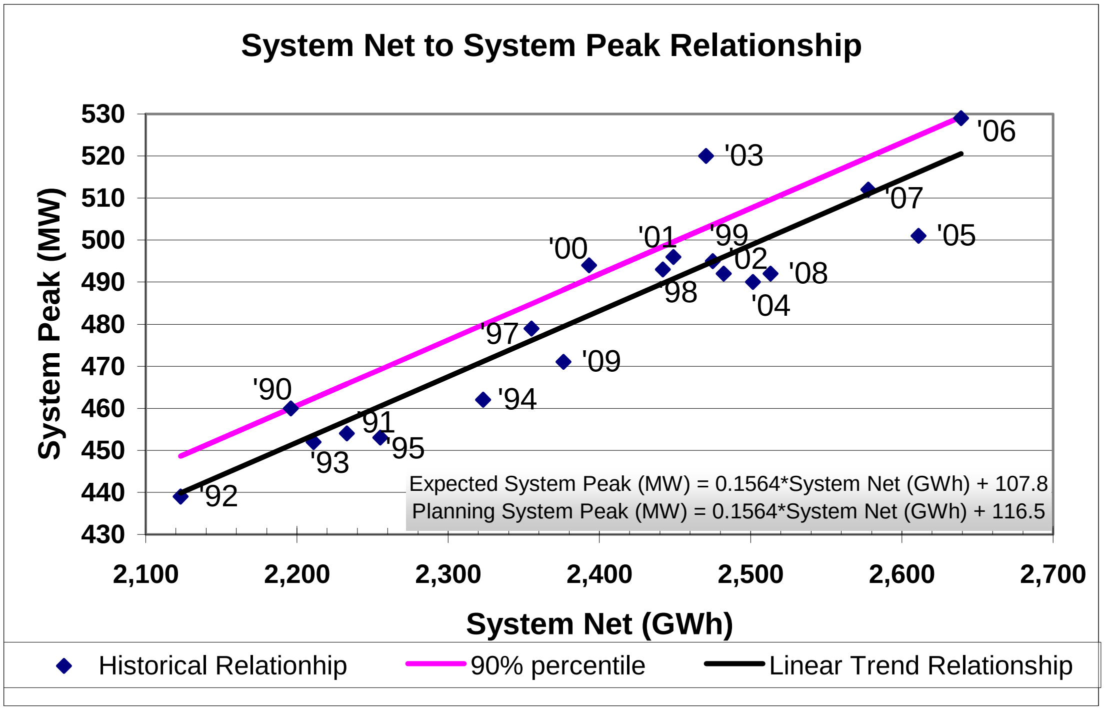
Customer Class	Losses		
	Transmission 0.44%	Primary 2.39%	Secondary 4.38%
Industrial	X		
Commercial	X	X	X
Residential	X	X	X
Schools	X	X	X
Hiway Lighting	X	X	X
County	X	X	X
Metered City of KCK	X	X	X
Unmetered City of KCK	X	X	X
BPU Inter-Departmental	X	X	X
Borderline	X	X	
Nearman Participating	X		
Wholesale	X		

Based on loss study completed November 2002 and adjusted for historical trends since the study was completed.

D. Peak System Demand

Peak system demand is calculated based on linear regression trend modeling of the historical peak plotted against the associated system net for the years 1990 through 2009. Figure 1 contains a plot of the system annual net energy and system annual peak demand. The black line in Figure 1 shows the historical trend line relationship between system annual net energy and system annual peak demand. The magenta line is drawn to represent the system net to system peak relationship that will result in a calculated peak equal to or greater than the actual peak 90% of the years used for the analysis.

Figure 1



In addition to its retail load responsibilities, the BPU has wholesale power supply contracts with the Kansas Municipal Energy Agency (KMEA) through 2021 and the City of Columbia, Missouri (Columbia) through 2022, based on their participation in BPU's Nearman Unit No. 1. Forecasts for energy sales to these off-system Nearman participation customers were calculated as the average of the last seven years sales to these participants, which is slightly lower than the average of the last three years. Recent Nearman Participating historical data and forecast energy appears in the table below:

Table 4
NEARMAN PARTICIPATING ENERGY

Year	Nearman Participating Energy (kWh)
2005	*313,903,000*
2006	*342,056,000*
2007	*377,888,000*
2008	*332,427,000*
2009	*434,356,000*
2010	398,063,000
2011	351,590,571
2012	262,441,000
2013	351,590,571
2014	351,590,571
2015	351,590,571
2016	351,590,571

The aggregate peak for Nearman Participants is 58MW, which is the sum of the KMEA and Columbia contract amounts. The historical energy varies from year to year. The forecasted energy is generally about 352 GWh/year however forecasted amounts are significantly lower some years because of longer scheduled outages related to major turbine and boiler maintenance on Nearman unit #1.

E. Forecast Results

The system load forecast developed by the BPU is shown in Table 5. The forecast includes sales to BPU's retail customers, borderline, city, BPU interdepartmental and losses. It does not include Nearman Participation customer sales or opportunity sales to the wholesale spot market.

Table 5
Load Forecast

Year	System Net		Growth (%)	Load Factor (%)
	Peak Demand (MW)	Total Energy (GWh)		
2004	*490*	*2,519*		*58.7*
2005	*501*	*2,630*	*4.39*	*59.9*
2006	*529*	*2,658*	*1.07*	*57.4*
2007	*512*	*2,597*	*-2.29*	*57.9*
2008	*492*	*2,532*	*-2.52*	*58.7*
2009	*471*	*2,393*	*-5.49*	*58.0*
2010	*489*	*2,459*	*2.79*	*57.4*
2011	493	2,483	0.95	57.5
2012	497	2,507	0.96	57.6
2013	499	2,519	0.51	57.7
2014	502	2,540	0.84	57.8
2015	505	2,562	0.85	57.9
2016	507	2,575	0.50	57.9
2017	509	2,588	0.50	58.0
2018	511	2,601	0.50	58.1
2019	513	2,613	0.50	58.1
2020	515	2,626	0.49	58.2
2021	517	2,639	0.49	58.2
2022	519	2,652	0.49	58.3
2023	521	2,665	0.49	58.4
2024	523	2,678	0.48	58.4
2025	525	2,691	0.48	58.5
2026	527	2,704	0.48	58.5
2027	529	2,717	0.48	58.6
2028	531	2,730	0.48	58.6
2029	533	2,742	0.47	58.7

BPU's base energy requirements are projected to grow at an average annual rate of about 1.5% over the next three years before leveling off at about a 0.5% per year average annual growth rate.

V. Current Resource Summary

The BPU's existing power supply resources include 614 MW of accredited generating capacity and 43 MW of hydro capacity purchased from the Southwestern Power Administration (SWPA) and the Western Area Power Administration (WAPA). The federal hydro power is available with firm transmission service and qualifies as firm capacity.

BPU's active generating plants include Nearman 1, a 232 MW pulverized coal unit operational in 1981, located at the Nearman Station. Also installed at the Nearman Station is CT 4, a 75 MW GE 7EA simple cycle combustion turbine commissioned in 2006. The Quindaro Station consists of a 72 MW pulverized coal steam turbine, Quindaro Unit 1, commissioned in 1966; and a 118 MW part coal fueled and part gas fueled steam turbine, Quindaro Unit 2, commissioned in 1971. Quindaro Unit 2 achieves its 118 MW accredited capacity by using natural gas as a supplemental fuel to Powder River Basin (PRB) coal which, due to coal pulverizer limitations, can only produce 95 MW. Both Quindaro Units 1 and 2 are dual-fuel capable and can be operated on natural gas alone.

The Quindaro Station also includes three simple cycle combustion turbines, CT 1, CT 2, and CT 3 with accredited capacities of 12, 56, and 46 MW, respectively. The online dates for these generators were 1969, 1974, and 1977. CT 1 can burn natural gas or No. 2 fuel oil. CT 2 and CT 3 burn No. 2 fuel oil.

The BPU system includes the inactive Kaw Station with three coal and/or gas fired steam generating units placed online between 1955 and 1962. All three units are in cold standby and would require extensive capital investment for equipment replacements and additions to be available as reliable generation resources in the future.

Currently, BPU anticipates retiring CT1, 2, and 3 in 2015, 2020, and 2023, respectively when they reach 45 years of age. Retirements of Quindaro Units 1 and 2 are dependant on economics and future environmental regulations as addressed later in this report. Table 6 contains a summary of the operating characteristics of the existing active BPU generators.

Table 6
Summary Operating Characteristics of Existing Active BPU Generators

Generator	Description	COD(1)	Max Net MW(2)	Min Net MW(2)
Nearman 1	Coal Steam	1981	220	120
Quindaro ST1	Coal Steam Cyclone	1966	72	64
Quindaro ST2	Coal Steam, Gas topping	1971	118	48
Quindaro GT1	Gas CT	1969	12	3
Quindaro GT2	Oil CT	1974	56	10
Quindaro GT3	Oil CT	1977	46	9
Nearman CT4	Gas CT	2006	75	46

(1) COD = Commercial Operation Date.
(2) Minimum and Maximum Output Capacities reflect the minimum and maximum continuous rating of the generator, in MW, at the conditions which it is expected to operate.

VI. CURRENT DEMAND SIDE PROGRAMS AND PAST INITIATIVES

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 (ESMP 2003). This section contains a discussion of green power alternatives that have been reviewed including wind and landfill gas to electrical energy. Many Power supply options have been examined by planning staff since the ESMP 2003.

Future Energy Efficiency and Demand Side Management programs will be evaluated with industry specific software such as Demand Side Management Option Risk Evaluator (DSMore™), a powerful financial analysis tool designed to evaluate the costs, benefits, and risks of DSM programs and services. DSMore provides all of the familiar cost effectiveness test results, including Utility Cost Test, Total Resource Cost Test, Ratepayer Impact Measure Test, and Societal Test. Moreover, these test results are provided for various weather conditions, including weather normal, and under a number of wholesale market conditions.

The programs described in this section are a continuation of those started either as a result of IRP or were started earlier as an effort to minimize cost and increase energy efficiency. They continue to be effective and generally require less attention and resources and thus are documented as IRP Programs.

A. System Load Factor Benefits

IRP planning and the programs implemented there under have contributed to an improvement (increase) in system load factor [a quotient of energy used (kWh) divided by the product of peak load (kW) and the number of hours in the year]. Generally speaking, an improvement in system load factor is desirable because it allows for more efficient use of existing equipment and lowers the per unit fuel cost.

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 things, 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 non-coincident peaks or high load factors; and weather factors. Programs implemented since the inception of the integrated resource planning process have aided in obtaining an improved load factor.

Improvements in load factor associated with integrated resource planning 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 at the time of peak loads. The result is that less fuel is used per kWh generated while at the same time there is an 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). Reductions in peak demand and use also save in the purchase of off-system power.

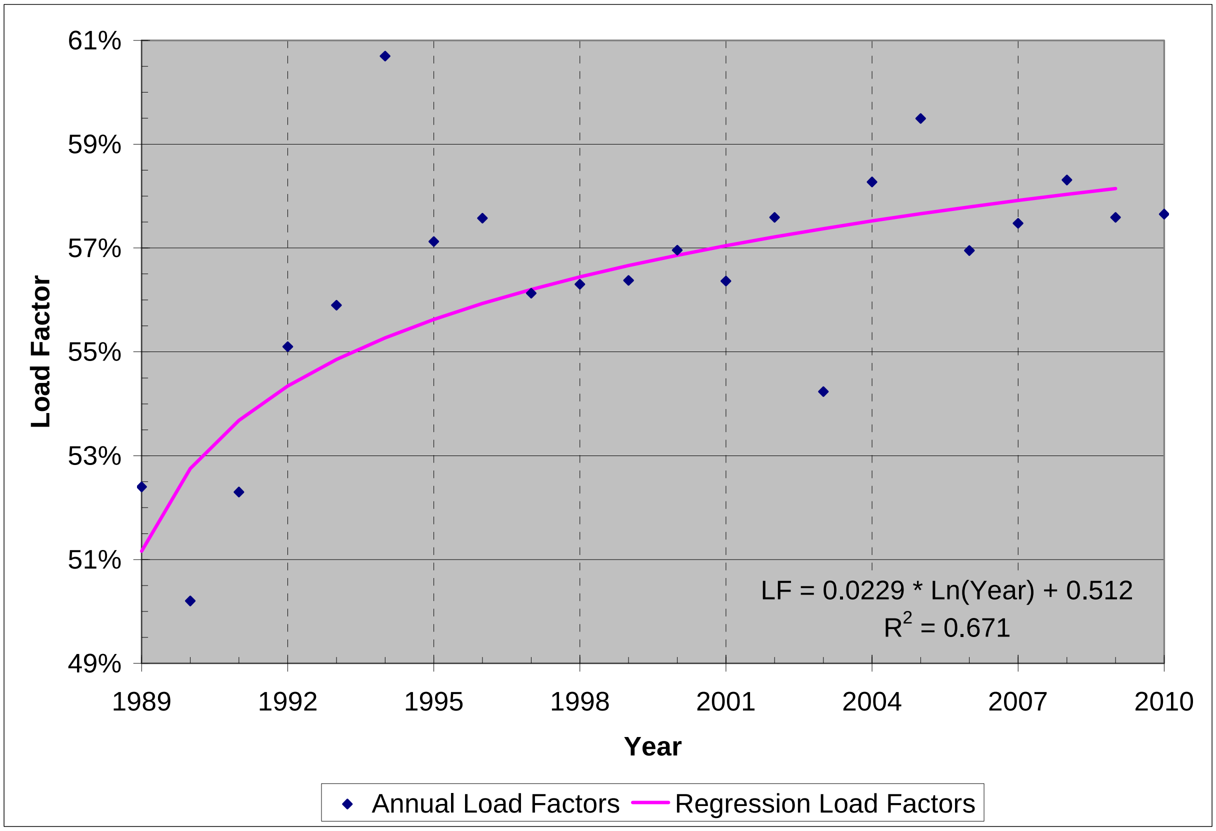
Table 7 lists the system load factor for the past 20 years. As can be seen from this table, the system load factor has improved since 1989; the year integrated resource planning began at BPU. In 1989 the system load factor was 52.4% at the outset of integrated resource planning, and in 2008 it was 58.2%. This improvement is beneficial, and while not all of the improvement can be attributed to integrated resource planning, a portion can be.

Table 7
System Load Factor
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	2,482,118	492	57.6%
2003	2,470,495	520	54.2%
2004	2,501,414	490	60.5%
2005	2,611,092	501	59.5%
2006	2,639,232	529	57.0%
2007	2,577,829	512	57.5%
2008	2,513,101	492	58.3%
2009	2,376,187	473	57.3%
2010	2,530,268	501	57.7%

Charting the above data yields the graph shown on Figure 2 on the following page. This graph shows a positive load factor trend line that is gradually increasing. This chart also shows variation associated with weather and other factors.

Figure 2
System Load Factor
Kansas City, Kansas Board of Public Utilities



The apparent random variations in the load factor from year to year are mostly due to weather effects. The general trend of improvement is due to the success of many of the programs undertaken by BPU. Some of the major contributors to this net change in system load factor have been the following:

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

A discussion and documentation of these programs follows.

B. Heat Pump and Hot Water Heater Rebate Programs

This program began in 2001 and continues today. The program is designed for both residential and commercial customers such that rebates are given to customers or builders who install or retro-fit energy efficient heat pumps or hot water heaters. The amount of rebates given to residential and commercial customers is provided on the BPU website, www.BPU.com. The BPU partners with the Energy Star Program and rebates are consistent with Energy Star recommendations.

Table 8 summarizes the rebate program since its inception in 2001. This table shows the revenues associated with the program along with its cost.

Table 8
Estimated Revenues and Cost Summary of the Rebate Program
Kansas City, Kansas Board of Public Utilities

Year	Total Cumulative Annual kWh	Total Cumulative Annual Revenues(1)	Rebates	Admin Labor Costs	Total Annual Costs	Annual Revenue to Total Annual Costs
2001	506,548	$8,747	$78,868	$124,715	$203,583	4%
2002	7,982,887	$247,654	$255,383	$241,504	$496,887	50%
2003	45,639,921	$1,533,554	$807,995	$332,319	$1,140,314	134%
2004	86,492,082	$811,677	$540,025	$328,386	$868,411	93%
2005	101,858,447	$1,026,336	$475,949	$300,000	$775,949	132%
2006	115,479,363	$1,318,188	$519,558	$297,541	$817,098	161%
2007	128,320,321	$1,875,039	$449,889	$129,261	$579,150	324%
2008	139,563,618	$2,083,524	$363,739	$109,208	$472,947	441%
2009	148,339,992	$2,241,322	$194,943	$80,343	$275,286	814%
Total	**774,183,177**	**$11,152,598**	**$3,686,347**	**$1,943,278**	**$5,629,625**	**198%**

(1) Total Annual Revenues based on net marginal revenue and total cumulative kWh.

The annual revenues, based on total cumulative kWh, since the inception of the program is slightly less than $2,250,000 or more than 8 times the annual cost of operation of approximately $275,000 after 9 years into the program's life cycle. This is not only a benefit to net revenue, but is also a benefit improving system load factor. As discussed earlier, an improved system load factor permits greater usage of more efficient generating equipment thus lowering the unit cost of energy and benefiting all customers. As one reviews Table 8, 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 and benefit grows.

Table 9 below illustrates another significant benefit of the BPU Rebate Programs. It shows the estimated capacity reduction associated with retrofitting older less efficient heat pumps and air conditioners with newer appliances. This retrofitting is primarily the result of the rebate program and tax credits by the federal government. Since inception, it is estimated that this program has reduced the capacity requirements by over 1.4 MW and has saved over $130,000.

Table 9
Estimated Capacity Reduction
Kansas City, Kansas Board of Public Utilities

Year	Summer Capacity Reduction (kW)	Cumulative (kW)	Summer Capacity Rate ($/kW-mo)	Annual Capacity Savings *
2001	49	24.4	$ 1.85	$ 181
2002	88	92.9	$ 1.85	$ 687
2003	176	224.8	$ 2.25	$ 2,023
2004	258	441.8	$ 4.00	$ 7,069
2005	217	679.4	$ 4.75	$ 12,908
2006	201	888.5	$ 5.09	$ 18,084
2007	186	1,082.1	$ 6.05	$ 26,187
2008	160	1,255.1	$ 6.05	$ 30,374
2009	143	1,406.6	$ 6.05	$ 34,040
Total	1,478			$ 131,553

* Based on 4 month purchase of summer capacity.

C. Street Light Replacement Program

As technology improved and equipment 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 utilized 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 a substantial savings in energy while providing better illumination. This program through 2008 has provided nearly a 23% energy savings. The street light information presented here in Table 10 and Table 11 is currently not available for 2009 and beyond. It is anticipated that the data will be available to include in the next annual update.

Table 10
Benefit Summary of Mercury Vapor Replacement Program
Kansas City, Kansas Board of Public Utilities

Year	No. HPS In Service	Total KWH Saved	Increase in KWH Saved
2001	5,803	3,866,313	NA
2002	6,032	4,004,030	137,717
2003	6,312	4,173,620	169,589
2004	6,916	4,569,539	395,919
2005	7,082	4,646,209	76,670
2006	7,252	4,752,162	105,953
2007	7,808	5,119,444	367,282
2008	7,854	5,144,640	25,196

Table 11
Total Illumination
Kansas City, Kansas Board of Public Utilities

Type	Size Watts	Lumens per Lamp[1]	Lamp Units in 2001	Total Lumens 2001	Lamp Units in 2008	Total Lumens 2008
HPS	100	9,500	873	8,293,500	1,089	10,345,500
HPS	150	16,000	0	-	10	160,000
HPS	250	27,500	4,724	129,910,000	6,536	179,740,000
HPS	400	50,000	206	10,300,000	219	10,950,000
		Total HPS:	5,803	148,503,500	7,854	201,195,500
MV	175	7,850	9,530	74,810,500	8,441	66,261,850
MV	250	12,000	1,714	20,568,000	1,693	20,316,000
MV	400	20,500	2,393	49,056,500	2,389	48,974,500
MV	1,000	57,000	2,316	132,012,000	2,327	132,639,000
		Total MV:	15,953	276,447,000	14,850	268,191,350
		Grand Total:	21,756	424,950,500	22,704	469,386,850
				Percent Increase from 2001 to 2008:	4.4%	10.5%

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

As can be seen above in Table 11, the total illumination increased by over ten percent from 2001 to 2008, whereas, during the same time period, the number of light fixtures increased by about four percent. Although not shown directly in Table 11, it can be inferred that annual energy consumption for street lighting also increased by about four percent, by comparing the sums of the products of the lamp quantities and lamp wattages in 2001 and 2008. Although the street light program has contributed to energy savings, because the BPU system peak has historically occurred during the day when streetlights are not operating, the street light program does not contribute to peak demand reduction.

D. Signal Light Replacement Program

Since December 2003, through the Signal Light Replacement Program, the BPU has replaced incandescent signal lights with LED lamps at approximately 56 locations and realized additional energy savings. The relative difference in power requirement for each head is significant, being in the range of 20 to 1. It is estimated that there is an annual savings of approximately 21,024 kWh at each location where these fixtures are converted.

Since the inception of this program the total energy savings is estimated to be over 1,300,000 kWh per year. This savings will continue to grow as long as there remain incandescent fixtures to be replaced; after that, the savings will continue on a year to year basis. In addition to the energy savings, the signal light replacement program has reduced the peak demand by about 135 kW compared to what peak demand would be assuming continued operation of incandescent signal lights.

E. Reactive Adjustment Rider

Customers with low power factors impose a burden on the electrical system causing a utility to increase its generation, transmission, distribution, transformer capacities and energy generation. Power factors are functions of real power (kW) and the apparent power (kVA) 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 117.6 kVA. An 85% power factor would require equipment with 17.6% 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 revised 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 an 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 12 below shows the history of the reactive adjustment program since records have been kept for the month of August. August is the month in which the system annual peak most frequently occurs.

Table 12
Power Factor Customer Data for the month of August
Kansas City, Kansas Board of Public Utilities

Year	Total Customers	No. of Customers with Reactive Charges	Percentage of Customers with Reactive Charges	Power Factor Penalty Revenues	Avg Reactive Charge Per Customer with Reactive Charge	Avg Reactive Charge Per Customer
2005	891	403	45.2%	$154,437	$383.22	$173.33
2006	936	410	43.8%	$184,290	$449.49	$196.89
2007	972	421	43.3%	$164,120	$389.83	$168.85
2008	1066	452	42.4%	$147,797	$326.98	$138.65
2009	1034	448	43.3%	$129,165	$288.32	$124.92
2010	1095	455	41.6%	$131,281	$288.53	$119.89

The data shows a downward trend from 2005 to 2010 in the percent of customers with less desirable power factors. The percentage of customers with low power factors in 2005 was slightly over 45% of customers with power factor metering, decreasing to less than 42% in 2010. The average reactive charge per customer with reactive charges shows significant reduction over the last five years, although it leveled off in 2010 compared to 2009. However, when considering all customers with power factor metering, the reactive charge per customer continued to decrease in 2010. The reduction in reactive charges is evidence that the rate change started in 2003 is working. BPU will continue to monitor the trends to see if power factor customers continue to improve their overall power factors.

F. Wind Power Energy

In the IRP of August 2005 two recommendations were made relating to wind power. The first recommendation was an evaluation of purchasing commercial wind power energy. Toward that end, the BPU entered into a 20 year Renewable Energy Purchase Agreement and began receiving wind generated energy from Smokey Hills Wind Farm in early 2008; however, due to a transformer failure late in 2008, BPU received only slightly more than 80,000 MWH. BPU is entitled to 25% of the wind farm’s output. The main step-up transformer is now operational, and energy from this source has been flowing since May 2009. BPU has been a leader of Kansas municipals with regard to purchasing Kansas wind energy. This purchase is over 5% of BPU’s 2010 system peak demand, based on nameplate capacity; and about 4% renewable wind energy based on 2010 retail load energy and expected capacity factor of the Smokey Hills Wind Farm. BPU chose to enter into wind energy at this level to gain experience with the issues related to the variability of wind, wind forecasts and other related wind integration issues. BPU is currently not required by any regulatory agency or mandate to purchase renewable energy; however, BPU management is committed to meeting the Kansas state Renewable Energy Standard. Kansas' standard is based on generation capacity (Megawatts). The compliance schedule is 10% by 2011, 15% by 2016, and 20% for 2020 and onward. Each MW of eligible capacity installed in Kansas after January 1, 2000 will count as 1.1 MW for the purpose of the Kansas standard. Because the Smokey Hills Wind Farm meets this criterion, its contribution is 27.7 MW. The Kansas standard specifies the percent compliance be based on the average of the three previous year peaks. In analyzing BPU’s relationship to the standard BPU chose the three highest year’s peak occurred in the years 2003, 2006, and 2007. The average peak over those three years is 520 MW. Therefore the Smokey Hills Wind Farm currently accounts for 5.3% towards the 10% standard.

The second recommendation was to evaluate the potential for local wind driven turbine. BPU concluded based on research of both wind options that a commercial scale wind facility was preferable over local community wind because of its lower cost due to wind location and economies of scale. A concern about entering into an agreement to purchase wind energy from a commercial wind facility remote from BPU’s service territory was whether the transmission system had the capacity to get the energy to BPU. Therefore, as part of the evaluation of the economics of the wind energy purchase SPP performed an analysis to evaluate the potential for curtailment of flows originating at Smokey Hills and sinking in the KC area. The results of this analysis was that it is not expected that the energy flow from Smokey Hills to BPU will be curtailed a significant percent of the time. The detailed analysis of the economics of the wind energy purchase is contained in Appendix C of this report.

The BPU has been given additional proposals for purchasing wind energy. The BPU has analyzed these proposals as they have been presented using production cost modeling similar to that done for the Smokey Hills Wind proposal. To date, none of the other proposals have been of economic benefit to the BPU. A contributing factor in the more recent proposals showing no benefit includes higher wind energy costs.

G. Landfill Gas Generator Purchase

The 2003 Master Plan recommended evaluation of Landfill Gas Generation as a renewable energy source but was narrowly focused on the potential for landfill gas generation at a local landfill. In 2009, BPU was approached by a project developer who had secured a source of gas at a private landfill in Arcadia, Kansas managed by Waste Corporation of America. After considerable due diligence and contract negotiation BPU entered into a Renewable Energy Purchase Agreement with the developer, Oak Grove Power Producers, LLC. The amount of gas generated by the landfill is estimated to supply a 1.5 MW generator (1.44 MW net) and may increase to a second generator as the landfill matures. The BPU has the right of first refusal for any additional generation added at the landfill.

The negotiated capacity cost for the Arcadia, Kansas landfill gas capacity is comparable, but slightly less than, the annual capital carry costs for a scrubbed new coal plant on a $/kW-yr basis based on Table 8.2 of the U.S. Energy Information Administration's Annual Energy Outlook 2010 as a reference for overnight construction costs. The negotiated energy cost for generation from the Arcadia, Kansas landfill site, is slightly less than the energy price forecasted by Ventyx in their semi-annual *Power Reference Case Electricity & Fuel Price Outlook*, on a long-term levelized cost basis. Energy deliveries started in March of 2010.
The Oak Grove Landfill Gas Energy purchase agreement is for a period of 20 years. The purchase agreement affords BPU a renewable energy resource without the variability of wind and solar. The methane gas produced in a landfill is a potent greenhouse gas, about 21 times more so than carbon dioxide, so the gases produced in a landfill must be collected and flared off or used to produce heat or electricity preventing the methane from migrating into the atmosphere where it contributes to local smog and global climate change. Using LFG to produce electricity results in beneficial use of the LFG. It was an opportunity to obtain base load generation without the carbon production from fossil fuel combustion and permitting difficulties of coal fired generation.

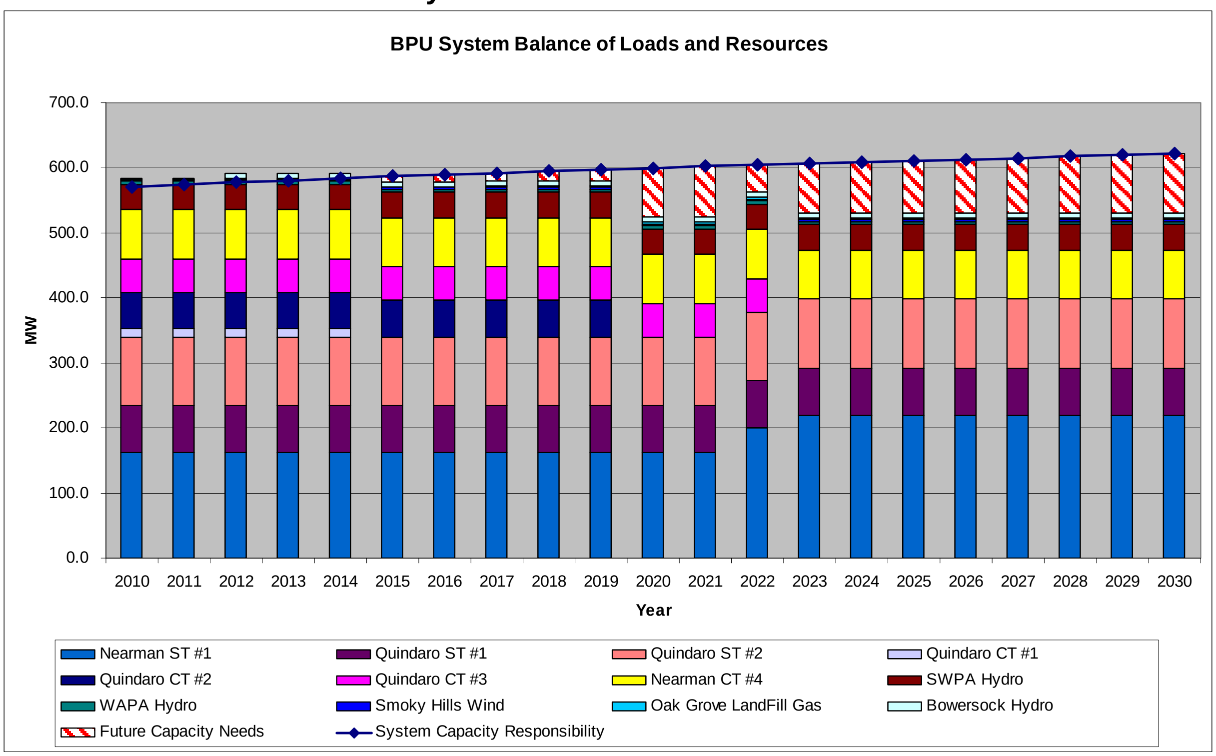
H. Net Metering

Although not discussed in the IRP of August 2005, net metering has been highly sought after by utility customers in Kansas and in May 2009, Kansas passed the Net Metering and Easy Connection Act which is applicable to Investor Owned Utilities (IOU's) only. The BPU, as a municipal utility, is not subject to that regulation, but has developed and adopted net metering and connection standards for Large, Medium, and Small Commercial and Residential customers to enable customer owned renewable generation sources.

VII. Future Resource Requirements Summary

The graph below in Figure 3 shows the BPU future resource requirements based on current demand forecasts. BPU currently has sufficient capacity to meet forecast demand through the year 2014. Beginning in 2015, BPU shows a need for additional firm capacity of approximately 10 MW coincident with the projected retirement of Quindaro CT #1. The need for additional firm capacity increases to about 20 MW by 2019. It is expected that this need can be met through summer capacity purchases from neighboring utilities with excess capacity. Quindaro CT #2 is expected to be nearing retirement by 2020, and when it is retired, BPU will require about 75 MW to meet its capacity shortfall. This additional capacity is shown in the graph below as the cyan bar labeled new generation or purchase. Previous planning studies have shown that a simple cycle combustion turbine with a summer capacity rating of about 75 MW to be the most economical resource expansion unit. Because the need for additional capacity is so far in the future, BPU will reevaluate those study results before moving forward based on those results.

Figure 3
BPU System Balance of Loads and Resources



BPU recognizes that the expected capacities of existing BPU generators and that the economics of the Quindaro Units' continued operation is a function of potential future environmental regulations. Economic studies have shown that the continued operation of the Quindaro steam coal units are the lower cost options to meet projected demand growth, however, BPU continues to study the costs associated with the continued operation of those units as environmental regulations change such that the BPU can continue to provide safe and reliable service to their customers at the lowest possible costs while complying with existing environmental regulations and other regulatory requirements.

VIII. FUTURE RESOURCE OPTION SUMMARY

BPU's integrated resource planning is a continuous process and the selection of programs to apply scarce resources is a dynamic process. One manifestation of the dynamic nature of this planning is that as programs mature (reach a point of diminishing returns) new initiatives are undertaken, which produce better marginal results. With this dynamic nature of the IRP process, it is not to say that existing programs are discontinued, but are simply allowed to continue (either with or without modification), but are de-emphasized with regard to the use of scarce resources. The new initiatives which appear to be fruitful are implemented with sufficient resources so as to make them effective. Once a program is implemented, then planning goes on to evaluate other options. In the process of developing plans, BPU management personnel are always looking for initiatives which will produce the greatest result with the least long-run investment and expense.

Studies done under the IRP umbrella have produced programs that have yielded cost reductions, increased the use of more efficient generating units, enhanced conservation, and improved net revenues. In general these activities have helped hold down rates. Studies have been made which have focused upon increasing the use of renewable or "green" resources as well as 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 utilized to replace older less efficient lamps while providing the same or greater level of lumens to the area or signal brightness.

Initial efforts by the BPU were aimed at improved energy utilization (increased off peak energy use) and less on conservation and demand reduction. The more recent plan focuses on energy efficiency and demand-side management.

Resource options considered viable are screened through cost analysis and penetration studies. 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 and costs. 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 will be pursued. The overall evaluation is typically done through the use of a long-term chronological production cost power supply modeling

Resource planning at the Kansas City Board of Public Utilities (BPU) is an ongoing process and the BPU has completed numerous studies regarding electric resources in the last five years. As opportunities for acquiring additional resources are presented, the BPU performs studies and analysis, and then decides how to proceed depending on the results of the analysis. The BPU has completed numerous studies regarding electric resources in the last five years. The following chronicles many of these studies.

In 2006, BPU commissioned a study for an independent review and update of the 2003 Kansas City Board of Public Utilities Electric System Master Plan. A conclusion of the study was that the most economical next new unit for BPU to meet projected demand is a nominal 235 MW pulverized coal unit. Subsequent to the completion of the 2006 Planning Study, in the first half of 2007, in a landmark case, the U.S. Supreme Court ruled that carbon dioxide and other global warming pollutants can be regulated under the Clean Air Act. The court also ruled that the EPA cannot refuse to regulate these pollutants for political reasons. In the first challenge since the ruling, the Sierra Club and Earthjustice petitioned the state of Kansas not to issue a permit for expansion of a coal-fired power plant proposed in Western Kansas unless it requires substantial controls for carbon dioxide. Subsequently, Secretary of the Kansas Department of Health and Environment, Roderick Bremby made an announcement in fall 2007 denying the air quality permit for Sunflower Electric Power Corporation's Holcomb Expansion. Bremby's decision was based on his opinion that additional carbon dioxide in the atmosphere presents a "substantial endangerment" to the public health of Kansans. Current EPA and Kansas regulations do not consider carbon dioxide a pollutant. The Secretary's decision sets aside KDHE professional staff's recommendation to issue the permit and disregards the extensive and exhaustive work completed by the KDHE technical staff to ensure that public health and the environment are protected, public concerns were addressed, and strict state and federal laws were followed.

A consequence of the Bremby decision was concern about the ability to permit a coal fired plant in the state of Kansas. Therefore, in 2008 the Kansas City Board of Public Utilities (BPU) performed a Ten Year Power Supply Plan study which considered natural gas fueled generation future resources capable of meeting the BPU’s need for firm generating capacity. One conclusion of the study was that it is less costly to continue to operate Q1 through 2017 rather than to retire it and replace it with a similar amount of combustion turbine based capacity. Of the expansion plans considered, the plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle configuration compared to a simple cycle configuration are not sufficient to offset the combined cycle’s incremental capital cost. In the least cost plan, BPU meets additional load growth with the addition of a 43 MW LM6000 type aero-derivative combustion turbine in 2011. The second least-cost plan also assumed Q1 remains in service and that two smaller (21 MW) LM2500 type combustion turbines are added for growth, one in 2011 and one in 2015. In the third least cost plan, a 75 MW Frame 7EA combustion turbine is added in 2011.

In 2009, after the completion of the 2008 10-yr Power Supply Plan study, BPU was able to obtain firm transmission service on its SWPA Hydro purchases through the SPP aggregate study process. The ability to obtain firm transmission service from the SWPA Hydro capacity provides 39 MW of accredited capacity to the BPU. Obtaining this capacity moved BPU’s need for additional capacity to the year 2015. Therefore, BPU will continue to monitor its demand growth and resource options to determine the most economical way to meet future capacity needs.

Following is additional documentation of many of the studies and analysis performed in the last few years.

A. Electric Master Plan Review and Power Market Assessment

In 2006, BPU commissioned a study for an independent review and update of the 2003 Kansas City Board of Public Utilities Electric System Master Plan. The study was conducted in parallel with a base load generation siting study designed to identify the most feasible site for new base load generation available to the BPU system. A wholesale power market assessment designed to identify neighboring utilities needing additional generation with the common goal of the acquisition of additional generating capacity and energy to meet the needs of a growing service area was performed as a component of this study. The benefits indentified in partnering with other utilities are two fold:

- Reduced costs to BPU customers from excess capacity that typically exists in the years immediately following the addition of the next major new generation resource, and

- Potentially significant economies-of-scale associated with the construction of generators larger than would be required to meet BPU's demand alone.

By conducting siting and market assessment studies concurrent with the Master Plan update, the BPU ensured that the costs of new generation resources considered reflect site specific conditions and cost-effective generator unit sizing. The concurrent studies also preserved the lead time required to design, permit, and construct new coal fueled generation for commercial operation in 2012 consistent with what the 2003 Master Plan indicated was needed.

This independent Master Plan review and update of 2006 addressed the future power supply needs of the BPU's native load customers, plus the wholesale power sales commitments under existing contracts through 2021-2022. The study also considered age and ability of the existing BPU generators to continue providing the level of economic and reliable service they have provided over the past 35 or more years. The period of study was the 25-year period 2006 through 2030.

The Master Plan review included the following elements:

- Forecast Need for Power--A review of previous BPU electric load and generating capacity requirement forecasts, a forecast of the capabilities and costs of existing BPU generators and power purchases, and a forecast of the timing and size of additional generating capacity needs.

- Characterization of New Power Supply Resources--Descriptions of the new power supply resources available to the BPU including conventional and renewable supply-side generation options, demand-side management programs designed to reduce the demand for power and possibly delay the need for new generation, and purchased power.

- Supply Side and Demand Side Resource Screening--A qualitative comparison of alternative resources with regard to their applicability to the BPU system along with a lifecycle cost comparison of the applicable options.

- Financial Comparison of Alternative Power Supply Plans--The identification of alternative plans to meet 2006-2030 generating capacity and energy needs and the comparison of these plans on a comparative revenue requirement basis. Includes associated risk and contingency analyses.

- Bilateral Power Market Description--A description of the potential availability of base load purchased power to be acquired in lieu of construction of a new BPU resource, and a description of the initial responses to a bridge power solicitation.

A conclusion of the study was that the most economical next new unit for BPU to meet the projected demand is a nominal 235 MW pulverized coal unit. The Executive Summary from that report is included in Appendix D.

B. 2008 Ten Year Power Supply Plan (The Gas Plan)

Subsequent to the 2006 Master Plan review and update, in late 2008, the Kansas City Board of Public Utilities (BPU) completed a Ten Year Power Supply Plan study. The 10-year power supply study considered natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The need for capacity was identified as the difference between forecast peak demand plus reserve requirements and the capacities of existing power supply resources. The study recognized the expected outputs of existing BPU generators and that the economics of the Quindaro Units' continued operation is a function of potential future environmental regulations, including the Regional Haze Rule and the ozone non-attainment conditions in the Kansas City metropolitan area. The study period was the 10-year period beginning 2008 through 2017. That study identified a need for between 35 and 107 MW of additional firm capacity by 2017, dependent upon whether or not BPU continues to operate Quindaro Unit 1 (Q1). The study consisted of the comparison of ten alternative generation expansion plans. Each plan was based on the use of simple cycle combustion turbines and/or combined cycle units burning natural gas as the primary fuel.

The study objective was to find the power supply plan that minimized overall costs to BPU customers during the ten-year study period under a range of plausible future conditions. The initial set of plan comparisons assumed forecasts of expected fuel prices, power purchase and sales price, load growth, sulfur dioxide (SO_2) allowance prices and carbon dioxide (CO_2) allowance prices. In addition, sensitivity analyses were conducted to compare the costs to customers under the following conditions:

- Gain of a large (28 MW) customer, at a load factor similar to the BPU system load factor.
- Loss of a large (28 MW) customer, at a load factor similar to the system load factor.
- High natural gas and electric market prices.
- A high cost for CO_2 emissions either as a result of a cap & trade program or the application of a carbon tax.
- No purchases of economy energy from the market reflecting an extreme case of transmission congestion.

One conclusion of the study was that it is consistently less costly to continue to operate Q1 through 2017 rather than to retire it and replace it with a similar amount of combustion turbine based capacity. Q1 was assumed to be required to be retrofit with a selective catalytic reduction (SCR) system for nitrogen oxide (NOx) control in order to continue operating through the study period. Of the expansion plans considered, the plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle configuration compared to a simple cycle configuration are not sufficient to offset the combined cycle's incremental capital cost during the 10 year planning period. In the least cost plan, BPU meets additional load growth with the addition of a 43 MW LM6000 type aero-derivative combustion turbine in 2011. The second least-cost plan also assumed Q1 remains in service and that two smaller (21 MW) LM2500 type combustion turbines are added for growth, one in 2011 and one in 2015. In the third least cost plan, a 75 MW Frame 7EA combustion turbine is added in 2011.

Because the NPV costs of the three least-cost plans calling for the addition of an LM6000 turbine, two LM2500 turbines or a 7EA turbine were so close, BPU selected the 7EA plan as the basis of the rate impact analysis in order to accommodate what is likely to be the most capital intensive of the least-cost plans and to allow BPU to maintain needed flexibility in procuring turbines.

C. Rate Impact Forecast

A rate impact study took the forecast of electric sales, operation and maintenance costs, and fuel and purchased power costs from the 2008 Power Supply Study and added debt service on existing capital facilities and forecast debt service on new generation plant additions as well as transmission, distribution, and administrative costs to produce a forecast of total revenue requirements. Included in the financial forecast were the latest forecasts of capital requirements for the existing generators as well as the expected capital and operating costs to meet potential environmental regulations for BPU's existing generators.

The power supply plan that adds a Frame 7EA combustion turbine in 2011 was close in NPV cost to the best plan when Q1 is not retired in 2011 and was the least cost plan on a NPV basis when Q1 is retired in 2011. Therefore, regardless of whether or not Q1 is retired early, a common low cost plan is to install a Frame 7EA in 2011. Accordingly, the financial forecast was developed using the projected costs of that plan and the assumption that Q1 will not be retired until after 2017. The results of the financial forecast indicated a total revenue deficiency under existing base rates of approximately $115 million for the period 2009 through 2013. To offset the annual revenue deficiencies, a series of consecutive annual base rate increases and an environmental surcharge (ESC) to recover the capital portion of potential environmental upgrades were recommended.

The rate impact forecast study recommended a series of three annual, six and one quarter percent base rate increases beginning in 2010 These recommended increases were determined with the assumption that proposed changes in the Energy Rate Component (ERC) calculation to recover additional energy supply costs be implemented beginning January 1, 2009. In addition, a new environmental surcharge (ESC) designed to recover all debt service payments for environmental capital improvements implemented beginning January 1, 2009 was recommended. The ESC would be adjusted annually to recover the upcoming year's debt service payment on the environmental bonds resulting from the potential emissions control retrofits on the Quindaro and Nearman coal fueled units. The projected ESC was 0.15 ¢/kWh in 2009, 0.40 ¢/kWh in 2010, 0.56 ¢/kWh in 2011, 0.83 ¢/kWh in 2012, and 0.67 ¢/kWh in 2013. The 2008 Ten Year Power Supply Study and Site Selection Study are included in Appendix E.

D. Dogwood-Magnolia Capacity/Energy Offers

Westar Energy offered for sale to BPU capacity and energy from two of their gas fired units. BPU performed an analysis of the offers for capacity and energy received from Westar Energy originating from the Dogwood & Magnolia power plants and determined that the capacity and energy offered for sale were not economic for BPU. Four offers were received for capacity and energy originating from Dogwood unit 3, a NG fueled CC unit. Three offers were on a day ahead notification basis for an 8 hr to 24 hr period and the fourth was a summer period (June-Sept) 5x16 must take option. The day ahead notification offers were each for different time periods: summer (June-Sept), July/Aug, and annual. The Dogwood offers were for variable quantities between 25 and 235 MWs. The Magnolia offer was for 235 MWs. BPU only needed about 25 MW of capacity, so the Magnolia offer for 235 MW was significantly more than the BPU's need for capacity and was not analyzed in detail.

One of the Dogwood offers was for the months of July and August only, and did not meet the summer period (June-Sept) capacity needs of the BPU, so it was not considered further. The Dogwood 5x16 option is an energy only option and was considered separate from the capacity needs analysis.

The Dogwood offers that include capacity included a charge for startup fuel and a specified $/start charge. For this analysis, it was assumed that the start charges (startup fuel plus other startup costs) would be shared by the recipients of the energy on a prorated basis. The prorated share of the start charge and start fuel cost was derived as the ratio of the BPU share of the energy to the total output of the unit. Since the total output of the unit can vary between the unit's minimum and maximum, a range on the expected start charges, reduced to a $/MWh basis, was computed. For the analysis, natural gas fuel cost was assumed to be $4/MMBtu, and the take duration was assumed to be the minimum 8 hours duration.

Although the startup costs on a $/MWh basis were lower if a longer take duration is assumed, this approach was used to analyze the offers' upper limit on the $/MWh start charge. The prorated startup costs range from $5.5/MWh to $13/MWh. The assumed NG price and the offered heat rate of 11,200 Btu/kWh plus $2.50/MWh yields an energy cost of $47.3/MWh. Adding in startup costs yields a net of between $52.8 and $60.3/MWh for energy including startup charges.

The energy only 5x16 offer has energy priced at $58/MWh, which is higher than the midpoint of the upper limit range on the cost of the energy associated with the combined energy/capacity offers. Therefore, it would likely be more economical to purchase energy at the summer period capacity/energy offer price. In addition, the energy only offer is a 5x16 must take offer, giving no flexibility on scheduling the energy. Therefore, it was determined that the 5x16 offer was not as good a fit to the BPU's needs as the day-ahead notification offer.

Of the three Dogwood day-ahead purchase options, the Summer (June-September) option was determined to be the best of the Westar offers. It offered a prorated average cost of about $57 per MWh. It also offered BPU the flexibility of purchasing power only when needed as opposed to the must take option that specifies payment of a fixed cost of $58 per MWh whether the energy is needed or not. The July-August option did not meet the SPP capacity purchase criteria, and the annual option requires a 12 month capacity payment commitment. Although the energy price is attractive on the annual offer, the requirement to pay for capacity in excess of that needed for reliability criteria made that offer unattractive. Using the assumptions stated above, and the offer's 8,000 Btu/kWh energy heat rate the calculated energy cost of the annual offer compared to the summer offer is about $13/MWh less. The breakeven point between the 12 month and summer option occurred at about 35 GWh. That is, with more than 35 GWh purchased, paying the lower per month capacity payment over the 12 months is more economical than the higher 4 month capacity payment because of the lower energy cost (approximately $35/MWh plus start charges) associated with the 12 month option. A detailed ProSym production cost model analysis showed that at the energy prices offered, the energy purchase options were not of economic benefit to BPU. Additionally, concurrent with the Westar offers' analysis, BPU was involved in studies to obtain firm transmission on the SWPA Hydro purchases. BPU was able to obtain firm transmission on the SWPA Hydro purchases, which satisfied BPU's capacity needs. Therefore BPU declined to accept any of these Westar offers.

E. SWPA Hydro Firming of Transmission

BPU has been purchasing hydro generated energy from SWPA for many years. BPU had buy/resell arrangements with two utilities to wheel the energy to BPU. In lieu of that arrangement, BPU requested long-term firm point-to-point transmission service of the SWPA hydro generation through the SPP aggregate study process. The SPP aggregates completed applications for long-term firm point-to-point transmission service into one aggregate facilities study (AFS). After an iterative series of AFS, SPP in conjunction with the applicable transmission owners determined the optimal set of transmission upgrades to minimize the overall costs for the transmission requests of the study group to reliably provide the requested firm transmission service.

BPU's allocation of costs for the transmission upgrades was less than the costs of obtaining the energy through the buy/re-sell arrangements. Through the granting of firm transmission service for the SWPA hydro generation, BPU is able to credit the SWPA hydro capacity of 39 MW as firm capacity towards the SPP mandated twelve percent minimum required capacity margin. In addition, the hydro generation purchase also contributes to the diversified mix of fuels used for serving the BPU demand, alleviating over reliance on one fuel type and contributing to a balanced portfolio of generation options that provides cost-effective, reliable, and safe service; and qualifies as renewable energy in Kansas.

F. Capacity and Energy Purchase from New Coal Facility

A participant of the Whelan Energy Center Unit 2, a nominally rated 220 MW pulverized coal-fired sub-critical generating unit fueled with low-sulfur coal located near Hastings Nebraska, offered 10 MW of baseload capacity beginning May 2011 through the end of 2013. It is expected that the Whelan project will be ready for commercial operation in February 2011.

The capacity and energy were offered at about $50/MWh assuming a forecast capacity factor of about 87%. The energy was offered under a must take arrangement. BPU performed production cost analysis under future scenarios that assumed two different natural gas price forecasts. Under the simulated conditions, the offer did not show positive net benefit to the BPU using a conventional cost/benefit analysis. However, the purchase power proposal did offer hedging benefit in locking in the energy price for the term of the offer. This may have been attractive under a scenario of prolonged outages of a baseload BPU unit during periods of high demand or unplanned outages during periods of high spot power prices. Another unknown regarding the purchase was the ability and cost of getting firm point to point transmission from the unit location to BPU. Based on the foregone analysis, it was decided by management not to execute an agreement to purchase the capacity and energy from Whelan.

IX. PROPOSED FUTURE INITIATIVES

A. General

Utilities face many challenges now and in the future. BPU is constantly evaluating its options with respect to capacity additions in light of regulatory uncertainty. Kansas renewable energy regulations have been enacted that exempt municipal utilities and use a different definition of renewable energy than the federal definition in the Energy Policy Act of 2005. Proposed federal regulations exempt smaller utilities from Renewable Portfolio Standards which may also exempt BPU from the final legislation.

Economic realities have reduced electrical demand and affected the ability of utilities and renewable energy developers to meet the demands imposed by financing entities to see renewable projects through to commercial operation. The possible economic viability of renewable energy projects are further affected by the factors that affect traditional fossil fuel generation resources:

- Escalating material and labor costs.
- Competition for engineering and construction services.
- Procurement lead times and costs.
- Volatile and increasing fuel costs.
- Changing Emissions Regulations.
- Changing Emission Technologies.
- Availability of financing.

The challenges facing new generation are significant and any deferral or reduction of capacity additions will have worthwhile dividends. BPU will continue to systematically challenge capacity addition decisions using available data on proven renewable and energy efficiency alternatives as well as conventional supply side alternatives. Following are examples of ongoing resource studies/analysis at the BPU.

B. Small Scale Hydro Expansion

BPU recently signed a contract with Lawrence, Kansas-based Bowersock Mills and Power Company (BMPC) to purchase 7 MW of hydroelectric power over the next 25 years, providing additional renewable energy resources to BPU's existing generating mix. Generation from the hydroelectric facility has been supplying electricity to Northeast Kansas on a limited basis since 1905. The dam is owned by Bowersock but maintained by the city of Lawrence, which depends on the dam to pool water for its Kaw River Water Treatment plant.

As part of the agreement, Bowersock will undertake a plant expansion project, building an additional powerhouse on its existing site while tripling the overall energy production capability. The project is expected to maintain Bowersock's current status as a "low-impact" hydropower plant.

Addition of the hydro generation power purchase agreement, BPU further expanded its alternative energy generating mix, which includes hydro, wind, and landfill gas energy capabilities. Renewable energy efforts like the Bowersock hydro partnership, as well as BPU's on-going energy efficiency and demand management efforts benefit both the community and the environment. The Bowersock hydro purchase provides BPU with a renewable energy source without the variability of wind and solar, additional base generation without the carbon production, and hydro energy from the facility for 25 years.

When the expansion is completed and BPU begins purchasing power from Bowersock, the municipal utility will have more than 15% renewable energy, exceeding the Kansas Renewable Energy Standards Act which calls for 10% for year 2011-2015, 15% for years 2016-2019, and 20% in 2020 and beyond. The project is expected to produce 33,000 MWh per year of energy (the equivalent of 188 railcars of coal), enough to supply electricity to 3,300 Wyandotte County homes. Moreover, the project will reduce overall CO2 emissions by more than 44,000 tons.

BPU performed an analysis on the economic feasibility of purchasing energy from the facility that led to the agreement. The expansion will include four turbines that will more than double the amount of electricity produced from the existing plant. Production costs simulations using the ProSym production cost model were used to determine the economics of the hydro generation purchase proposal. The analysis was performed for a combination of future scenarios that assumed two different natural gas price forecasts, and with and without CO2 emission reduction mandates over a 25 year period. The analysis showed a net positive benefit to BPU, assuming equal likelihood of each scenario.

C. Joint Resource Planning Study: Power Supply Options for Kansas

BPU is participating in a joint resource planning study to determine a viable power supply plan that meets the power supply needs of all the participants at cost that is more cost-effective than if the participants develop individual plans. Active project participants are: Kansas Municipal Utilities (KMU), Board of Public Utilities of Kansas City (KCKBPU), Kansas Municipal Energy Agency (KMEA), and the Kansas Power Pool KPP).

Power supply data was compiled and analyzed power supply data for the KMU membership as a whole as well as an approach to the individual agency power supply needs of KMEA, KPP and Kansas City BPU. At this time initial resource plan drafts are being reviewed by the participants.

X. ENVIRONMENTAL BENEFITS

The Kansas House enacted a Renewable Energy Standard (RES) in May 2009. The bill established a RES for Kansas that requires the state's investor owned utilities and certain cooperative utilities to generate or purchase certain amounts (10% by 2011; 15% by 2016; and 20% by 2020) of their electricity from renewable resources. Kansas' RES is based on generator nameplate capacity, not on retail electric energy sales. Recently, in Fall 2010, the Kansas Corporation Commission (KCC) established rules and regulations to administer the RES including equations for calculating capacity for the utilities. The required generation capacity can be produced by wind, solar thermal, photovoltaic (PV), dedicated crops grown for energy production, cellulosic agricultural residues, plant residues, methane from landfills or wastewater treatment, clean and untreated wood products such as pallets, existing hydropower, new hydropower that has a nameplate rating of 10 megawatts (MW) or less, fuel cells using hydrogen produced by an eligible renewable resource, and other sources of energy that become available in the future and are certified as renewable by the KCC. Each MW of eligible capacity installed in Kansas after January 1, 2000 will count as 1.1 MW for the purpose of compliance.

As a municipal utility, BPU is not bound by the Kansas RES. However, BPU is committed to voluntarily meeting the state's RES. BPU currently purchases renewable energy in the form of hydro, wind, and land fill gas, as summarized in Table 13 below, towards voluntarily meeting the state's RES. BPU purchases hydro generation from SWPA and WAPA, wind energy from the Smoky Hills Wind plant, and land fill gas generation from the Oak Grove LFG facility. An agreement to purchase low impact hydro from an expansion of the Bowersock Hydro plant has recently been completed.

Table 13
BPU Capacity and Energy from Renewable Resources

	Qualifies for Kansas RES?	EPAct 2005 Renewable?	Name Plate Capacity (MW)	LFGTE Future Capacity (MW)	LFGTE Production Life (Yrs)	Kansas Accredited Capacity (MW)	Federal Accredited Capacity (MW)	Capacity Factor	Federal Renewable Energy (GWh)
SWPA	Y	N	38.6			38.6	0.0		69.5
WAPA	Y	N	4.8			4.8	0.0		14.9
Smoky Hills Wind	Y	Y	25.2			27.7	25.2	44%	97.1
Oak Grove LFGTE	Y	Y	1.5	3	30+	1.7	1.5	90%	11.8
Bowersock Hydro	Y	Y	7.0			7.7	7.0	55%	33.7
Kansas Renewable Capacity (MW) & Federal Renewable Energy (GWh)						80.5			142.7
Annual Carbon Offset (MWh)									227.1

In regards to the Kansas RES, BPU currently purchases about 14% by capacity towards the Kansas RES (see Table 14 below). This amount of renewable generation voluntarily meets the Kansas RES through 2015. With the addition of the Bowersock hydro generation purchase, BPU will increases its renewable generation, by capacity, to over 15%, based on the average of the highest three years MW peaks. This will meet the Kansas RES through 2019, assuming the average three highest years peak does not exceed 536 MW before then. Based on average annual retail energy sales and estimated capacity factors of existing purchases, the BPU is meeting about five percent of retail sales through current renewable generation purchases. When the Bowersock expansion comes on line in 2012 the BPU will be meeting about six percent of annual retail sales with renewable generation.

Table 14
BPU Capacity and Energy Summary from Renewable Resources

<table>
<tr><th></th><th colspan="2">Current</th><th colspan="2">with Bowersock</th></tr>
<tr><td>Kansas Accredited Capacity (MW)</td><td>73</td><td rowspan="2">14.0%</td><td>80</td><td rowspan="2">15.5%</td></tr>
<tr><td>Average 3 Highest Years Peak (MW)</td><td>520</td><td>520</td></tr>
<tr><td>Federal Renewable Energy (GWh)</td><td>109</td><td rowspan="2">4.7%</td><td>143</td><td rowspan="2">6.2%</td></tr>
<tr><td>Average Retail Energy (GWh)</td><td>2,312</td><td>2,312</td></tr>
</table>

Nearman ST1 and Quindaro ST2 are scheduled to be retrofitted with low NOx burners (LNB) and over fire air (OFA) in Spring 2012 and Fall 2011, respectively. The LNB and OFA retrofits are expected to lower NOx emissions to about 0.23 lb/MMBtu. This reduction will help improve the air quality in the Kansas City metropolitan area.

XI. ACTION PLAN

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. These programs 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. The Street Light Replacement Program, replacing Mercury Vapor lamps (MV) with more efficient High Pressure Sodium (HPS) lamps will continue. It is expected that about 235 Mercury Vapor lights will be installed each year resulting in the energy savings shown in Table 15 below.

Table 15
Forecast of Benefits of Mercury Vapor Replacement Program

Year	# HPS lights	kWh Savings	Increase in KWh Savings
2010	8,322	5,436,383	145,872
2011	8,556	5,582,255	145,872
2012	8,791	5,728,127	145,872
2013	9,025	5,873,999	145,872
2014	9,259	6,019,871	145,872
2015	9,493	6,165,743	145,872

Since December 2003 the BPU has replaced incandescent signal lights with LED lamps under the Signal Light Replacement Program and plans to continue this program. During the first four years of the program, signal lamps were replaced with LED lamps at 56 intersections. This pace of replacement is expected to slow due to budgetary cutbacks in capital expenditures. At the rate of ten to eleven intersections per year getting signal lamp replacements, it is expected that the annual energy savings will be as shown in Table 16 below.

Table 16
Forecast of Benefits of Traffic Signal LED Replacement Program

Year	# Intersections with Traffic Signal LED lights	Cumulative kWh Savings	Increase in kWh Savings	Cumulative kW Savings	Increase in kW Savings
2010	77	1,618,848	210,240	185	24.0
2011	88	1,850,112	231,264	211	26.4
2012	98	2,060,352	210,240	235	24.0
2013	109	2,291,616	231,264	262	26.4
2014	119	2,501,856	210,240	286	24.0
2015	130	2,733,120	231,264	312	26.4

The BPU encourages use of energy efficient appliances and devices. BPU plans to continue the Heat Pump and Hot Water Heater Rebate Programs which are designed for both residential and commercial customers. The programs, which have been implemented, have been successful and generally improved energy use. Savings associated with the Heat Pump and Hot Water Heater programs are expected to be as shown in Table 17.

Table 17
Estimated Revenues and Cost Summary of the Rebate Program
Kansas City, Kansas Board of Public Utilities

Year	Residential Total Cumulative Annual kWh	Commercial Total Cumulative Annual kWh	Total Cumulative Annual kWh	Summer Capacity Reduction (kW)	Cumulative (kW)
2010	41,154,646	115,359,070	156,513,716	112	1,534.0
2011	44,271,294	119,671,739	163,943,033	111	1,645.4
2012	47,347,963	123,984,406	171,332,368	110	1,756.1
2013	50,407,534	128,297,073	178,704,607	110	1,866.4
2014	53,459,888	132,609,740	186,069,628	110	1,976.6
2015	56,509,222	136,922,407	193,431,629	110	2,086.7

Future programs are being evaluated. Future programs considered worthy of consideration will be evaluated and, if implemented, most likely will achieve many of these same results. BPU plans to perform an evaluation of a residential and commercial photovoltaic rebate programs. BPU also plans to evaluate aggregate commercial and industrial load curtailment programs and a residential and small commercial thermostat setback program.

Results of recent planning studies indicate that the BPU will likely need additional supply side resources in 2015. Based on current projections, the BPU expects to be between about 10 and 20 MW below the SPP summer capacity requirement in the 2015-2019 timeframe. BPU expects to meet the summer capacity needs either through self-build of a new combustion turbine, joint participation in a new-build generator, and/or through the purchase of excess capacity of neighboring utilities, as has been done in recent years through bi-lateral contracts. Since the anticipated need for new supply-side resources is five years out in the future, there is sufficient time for the BPU to diligently consider all the options before committing to one or the other. Changes to EPA power plant emission regulations that are currently being considered and under review by the EPA, but not finalized, will influence BPU power supply decisions. The rate of recovery and growth of the local economy subsequent to the current recessionary climate will also play a role in the decisions going forward. Although plans for new generation are not on the immediate drawing board, as either the opportunity or need for additional generation or purchases avails, the BPU will evaluate and consider the opportunities.

Although the BPU does not have immediate need for additional supply-side resources, the BPU will continue to evaluate opportunities for additional supply-side and demand-side resources for environmental and economic benefit. If the resources are of benefit to the BPU and its customers, the resources will be integrated into the existing resource mix towards meeting current and future needs. BPU will quantify the number of studies completed each year and include a synopsis and the results of evaluations conducted in the comment section of the IRP annual updates.

XII. PUBLIC PARTICIPATION

Communication with its customers has always been a hallmark of the BPU. 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. The committee consisted of 10 volunteer 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 BPU. In addition to these public forums and meetings with special groups, there have been numerous communiqués to inform the customer base of important events and 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 three meetings with regard to the transmission line to the facility. As conditions change and new programs are considered meetings with BPU's customers will be held to obtain public input and support.

In keeping with this tradition and the Federal Regulations, 10 CFR Part 905.11, governing the public participation requirements in developing BPU's IRP, the BPU is initiating this public process starting with this publication of the IRP:

1. Publication in Draft format posted with a downloadable link at the BPU web site, www.BPU.com, with paper or electronic copies available for the public upon request. Requests should be submitted to:

   Director of Electric Supply Planning
   Kansas City Board of Public Utilities
   Electric Supply Administration Office
   PO Box 2409
   Kansas City, KS 66102

   Attention: Blake Elliott

   or by e-mail at:

   belliott@bpu.com

2. Upon posting, a notice will be published in the utilities current Publication of Record for official notices. This notice will open a 30 day public comment period and announce the date and time of the public meeting. At the meeting, BPU staff will explain the IRP process, present information in the IRP and receive comments from the public.

3. At the completion of the public comment period the BPU will have 30 days to incorporate the comments into the report with a full copy of all comments included in the last appendix of the IRP.

4. Upon the publication of the IRP the elected members of the Board will have 30 days to approve the Integrated Resource Plan - Final Copy. Approval of the document constitutes the passing of a Board Resolution authorizing the General Manager to certify the submittal to Western Area Power Administration that the IRP meets all requirements set forth in 10 CFR Part 905 applicable to the Board of Public Utilities of Kansas City, Kansas.

5. An executed copy of the Board Resolution and one bound copy of the Integrated Resource Plan will be mailed to WAPA at their current address for legal notices. An electronic copy of the IRP will be made available to WAPA for publication on their web site and the current copy of BPU's WAPA-approved IRP will be maintained on BPU's web site during the term of our agreement with WAPA to meet the requirements of current regulations governing WAPA IRP customer transparency.

Appendix A

PUBLIC COMMENTS

APPENDIX A - PUBLIC COMMENTS TO KANSAS CITY BOARD OF PUBLIC UTILITIES OCTOBER 2009 INTEGRATED RESOURCE PLAN

This supplement to the Board of Public Utilities (BPU) Integrated Resource Plan (IRP) is to describe a second public participation opportunity associated with the October 2009 Draft IRP. The Western Area Power Administration (WAPA) requested that BPU offer a second public participation opportunity in order to more fully implement Department of Energy regulations at 10 CSR 905.11(b)(4). BPU offered additional participation opportunities in 2010 and 2011. This Supplement provides the brief description of the public involvement activities required by 10 CSR 905.11(b)(4) and WAPA guidelines.

Public Comment Opportunities

BPU has conducted two 30 day public comment periods for the October 2009 Draft IRP. The first 30 day comment period was announced February 9, 2010 by notice in the local on-line newspaper, the Kansas City Kansan. Please see Exhibit A-1.

On March 16, 2011, BPU provided the public with a second 30 day comment opportunity. BPU's announcement of the 30-day public comment period was posted on BPU's website and on the on-line newspaper publications of Wyandotte Daily News, the Kansas City Examiner and the Kansas City Star. BPU made the draft IRP available for download on the BPU web site, www.BPU.com. Please see Exhibit A-2. Paper copies of the IRP were maintained and available to the public to view at each of the Wyandotte county public library branches; and upon request to BPU. BPU accepted written comments by e-mail or by mail at BPU's headquarters from March 18, 2011 through April 17, 2011. BPU also noted in its announcement of the 30-day public comment period that an overview of the draft IRP would be presented to the public on April 6, 2011 at BPU's Board Meeting, where the public would have also the opportunity to comment. Please see Attachment B. Five written comments were submitted in response to the two notices of opportunity to comment.

Public Meeting

At the April 6, 2011, BPU Board Meeting, BPU presented a summary of the IRP process and of the October 2009 Draft IRP. Approximately 25 people attended the Board Meeting of which the IRP was one of other agenda items. Attendees included members of the general public and representatives from local governments, non-governmental organizations and other special interest groups. Attendees were offered the opportunity to comment.

With respect to the IRP process, the schedule for IRP submittal and the submittal dates for the October 2009 Draft IRP were presented. BPU and WAPA have worked on that submittal in a collaborative process to make revisions to the IRP. WAPA has provided BPU the extensions necessary for timely preparation and approval of the IRP.

At the April 6, 2011 BPU Board Meeting a summary of the purpose of the IRP was presented together with a summary of the basic IRP requirements (Exhibit A-6). Among the topics presented were:

- A summary of BPU's demand side programs to promote energy efficiency including rebates, zero interest loans for energy efficient equipment, and replacement of traffic and street lights with energy efficient lighting;

- BPU partnerships with energy producers for renewable or clean energy;

- Extensive information describing BPU's renewable energy portfolio that includes recent additions of 25 MW of wind energy, 1.5 MW of methane gas energy, 7 MW of hydro electric energy;

- An explanation of the parameters for BPU's opportunities for further development of its renewable portfolio; and

- An explanation that the BPU is not pursuing construction of additional coal-fired electric generation.

The public was offered the opportunity to comment. Three people provided verbal comments. The comments primarily reached to issues beyond the purview of the Department of Energy IRP process. These comments expressed concerns regarding pollution and health impacts from the generation of electricity from the burning of coal and existing and proposed federal regulations potentially requiring additional air quality control systems on electric generating units burning coal.

Public Input Received During the IRP Process

Public input received during the two public participation opportunities covered a wide spectrum of subjects. This assisted the BPU in identifying the concerns of the public relevant to IRP requirements.

PUBLIC INPUT	BPU RESPONSE
Rate increases and required employee furlough should be discussed.	In depth rate discussion in an IRP is not within the scope of Department of Energy IRP regulations. However, through other processes BPU is regularly engaged in rate evaluation and in other activities to provide economical delivery of electric service.
Deadlines for IRP Process should be addressed.	The IRP is timely submitted.
Environmental impacts of coal-fired generation and the application of and changes in environmental regulations should be addressed	The IRP has been reviewed to confirm compliance with Department of Energy regulations relating to environmental impacts. The IRP discusses environmental considerations and the uncertainties presented by potential new environmental regulations.
Coal-fired units should be retired.	The IRP has been reviewed to confirm adequacy of discussion of Department of Energy regulation requirements relating to generation options and mixes. The IRP discusses generation options, including potential unit retirements.
The modeling analysis should be made available to the public.	All the modeling assumptions are presented in the 2008 Ten Year Power Supply Study which is an appendix to the IRP.
Use of 'out of date' studies.	BPU considers all planning reports to be living documents, subject to ongoing updates with the rapid changes in the industry. Past studies remain a valuable reference component of current planning.
Fuel switching for Q1 and Q2.	The potential economics of switching existing coal units to natural gas is dependent on the potential outcomes of future regulations and is a subject for future planning studies.

Need for revised load forecast based on economic down-turn.	The IRP includes an updated load forecast that reflects the drop in BPU load resulting from recent economic conditions.
Compliance with the State of Kansas Renewable Energy Standards.	Kansas' RES is based on capacity, not energy, and allows the inclusion of Hydro power from SWPA and WAPA. BPU is in compliance with the Kansas RES on a voluntary basis.
Use of outdated gas prices.	BPU receives natural gas pricing on a regular basis from multiple sources, including natural gas forecasts for future years, and updated models with new gas pricing as appropriate.

Exhibit A-1. IRP Public Comment Period News Release (Feb 9th 2010).

Published on *The Kansas City Kansan* (http://www.kansascitykansan.com)

Home > Blogs > 's blog > BPU taking public comment on 2010 IRP

BPU taking public comment on 2010 IRP

By *Anonymous*
Created *Feb 9 2010 - 3:16am*

The Kansas City Board of Public Utilities (BPU), in accordance with Federal Regulation, 10 CFR, Part 905.11, is taking public comment and making available for review its draft 2010 Integrated Resource Plan (IRP).

Integrate 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.

Such planning 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 planning process that is updated as conditions, prices, costs, technologies and power requirements change.

The object of such planning is to find a least cost solution which will supply customers the amount and quality of electric service they desire while at the same time promoting the utility's long term financial health.

BPU is required by law to file an Integrated Resource Plan (IRP) with Western Area Power Administration (WAPA), an Agency of the U.S. Department of Energy, and update the plan every five years. As part of this requirement, BPU must also submit annual progress reports and the status of its IRP. The report being made available is the draft BPU's 2010 IRP.

Public comments on BPU's draft 2010 IRP will be accepted for 30 days from notice of this publication. Comments can be forwarded to the Director of Electric Supply Planning, Blake Elliott using any of the contact methods which appear below.

Paper print copies of the draft 2010 IRP are available to the public by request. To receive a print copy, please contact:

Director of Electric Supply Planning
Board of Public Utilities
312 N. 65th Street
Kansas City, Kansas 66102
Att: Blake Elliott

Electronic copies are available by submitting requests to belliott@bpu.com [1], and are also available on BPU's website at the following link:

http://www.bpu.com/documents/Integrated%20Resource%20Plan%202010.pdf [2]

Exhibit A-2. IRP Public Comment Period News Release from bpu.com Website (March 18 2011).

Kansas City Board of Public Utilities

Serving the Water and Electric Needs of Kansas City, Kansas

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SEARCH

3-16-2011

BPU Takes Public Comment on 2009 Integrated Resource Plan (IRP)

(KANSAS CITY, Ks.) The Kansas City Board of Public Utilities (BPU), in accordance with Federal Regulation, 10 CFR, Part 905.11, is taking public comment and making available for review its draft 2009 Integrated Resource Plan (IRP).

Integrate 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. Such planning 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 planning process that is updated as conditions, prices, costs, technologies and power requirements change. The object of such planning is to find a least cost solution which will supply customers the amount and quality of electric service they desire while at the same time promoting the utility's long term financial health.

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Electronic copies are available by submitting requests to belliott@bpu.com, and are also available on BPU's website at the following link: http://bpu.com/documents/Temp/Draft%20IRP%20for%20Public%20Comment%202009.pdf

Paper print copies of the IRP are available to the public to view at each of the WYCO public library branches. Branch locations can be found at the following link http://www.kckpl.lib.ks.us/LOCATE.HTM

At the regularly scheduled Board Meeting on April 6, 2011 staff will present an overview of the IRP Plan and public comments will be received. The meeting begins at 6:00PM and is held at the BPU Administrative Office at 540 Minnesota Ave., Kansas City, KS.

Public comments on BPU's draft 2009 IRP will be accepted for 30 days March 18, 2011 through April 17, 2011. Comments can be forwarded to belliott@bpu.com or at the address below:

Director of Electric Supply Planning
Board of Public Utilities
540 Minnesota Ave.
Kansas City, Kansas 66101
Att: Blake Elliott

For additional questions regarding the draft 2009 IRP, please contact Blake Elliott at 913-573-6837.

About BPU
BPU's water department was originally created in 1909, and its electric utility was operational in 1912. The purpose of the utility, then and to this day, is to provide the highest quality electric and water services at the lowest possible cost. Today the publicly owned utility serves approximately 65,000 electric and 51,000 water customers, primarily in Wyandotte County, Kansas. The mission of the utility and its employees is "to focus on the needs of our customers, to improve the quality of life in our community while promoting safe, reliable and sustainable utilities." BPU's Web site is www.bpu.com.

Site Map

View/Subscribe to Newsletter

Emergency Numbers:
Electrical outages:
(913) 573-9522
Water leaks or outages:
(913) 573-9622

Kansas City, Kansas has not had a print newspaper since the Kansan ceased publication several years ago. However, local news is covered by two more localized web based publications and a metropolitan newspaper. BPU's press release was picked up by the Wyandotte Daily News, the Kansas City Examiner and the Kansas City Star newspaper. Postings on their websites are shown in Exhibits A-3, A-4 and A-5 respectively.

Exhibit A-3. IRP Public Comment Period News Release from WyandotteDailyNews.com Website.

WyandotteDailyNews

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BPU takes public comments on 2009 integrated resource plan

The Kansas City Board of Public Utilities is taking public comment and making available for review is draft 2009 Integrated Resource Plan.

The action is in accordance with Federal Regulation, 10 CFR, Part 905.11, according to a BPU spokesman.

Integrated Resource Planning 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. Such planning 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 ongoing planning process that is updated as conditions, prices, costs, technologies and power requirements change. The object of such planning is to find a least cost solution which will supply customers the amount and quality of electric service they desire while at the same time promoting the utility's long term financial health.

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Public comments on BPU's draft 2009 IRP will be accepted for 30 days March 18, 2011, through April 17, 2011. Comments can be forwarded to This e-mail address is being protected from spambots. You need JavaScript enabled to view it or at the address below:

Director of Electric Supply Planning

Board of Public Utilities

540 Minnesota Ave.

Kansas City, Kansas 66101

Att: Blake Elliott

For additional questions regarding the draft 2009 IRP, contact Blake Elliott at 913-573-6837.

Exhibit A-4. IRP Public Comment Period News Release from the Kansas City Examiner.

examiner.com
the insider source for local

Kansas City
Board of Public Utilities

BPU's 2009 Integrated Resource Plan

By Bettse Folsom, Greater Kansas City Examiner
March 16th, 2011 10:38 pm ET

BPU Takes Public Comment on 2009 Integrated Resource Plan (IRP)

The Kansas City Board of Public Utilities (BPU), in accordance with Federal Regulation, 10 CFR, Part 905.11, is taking public comment and making available for review its draft 2009 Integrated Resource Plan (IRP).

Integrate 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. Such planning 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 planning process that is updated as conditions, prices, costs, technologies and power requirements change. The object of such planning is to find a least cost solution which will supply customers the amount and quality of electric service they desire while at the same time promoting the utility's long term financial health.

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Electronic copies are available by submitting requests to belliott@bpu.com, and are also available on BPU's website.

Paper print copies of the IRP are available to the public to view at each of the WYCO public library branches. Branch locations can be found at this link

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Att: Blake Elliott

Director of Electric Supply Planning

Board of Public Utilities

540 Minnesota Ave.

Kansas City, Kansas 66101

For additional questions regarding the draft 2009 IRP, please contact Blake Elliott at 913-573-6837.

Exhibit A-5. IRP Public Comment Period News Release from the Kansas City Star newspaper.

BPU takes public comment on 2009 Integrated Resource Plan (IRP)

By christy
Created Mar 18 2011 - 2:39pm

NEWS RELEASE

KANSAS CITY BOARD OF PUBLIC UTILITIES
OFFICE OF PUBLIC AFFAIRS
540 Minnesota Avenue
Kansas City, KS 66101

Contact: David Mehlhaff Date: March 17, 2011
Public Information Officer Phone: (913) 573-9173 For Immediate Release
E-mail: dmehlhaff@bpu.com
Web site: www.bpu.com

BPU takes public comment on 2009 Integrated Resource Plan (IRP)

(KANSAS CITY, Ks.) The Kansas City Board of Public Utilities (BPU), in accordance with Federal Regulation, 10 CFR, Part 905.11, is taking public comment and making available for review its draft 2009 Integrated Resource Plan (IRP).

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Director of Electric Supply Planning
Board of Public Utilities
540 Minnesota Ave.
Kansas City, Kansas 66101
Att: Blake Elliott

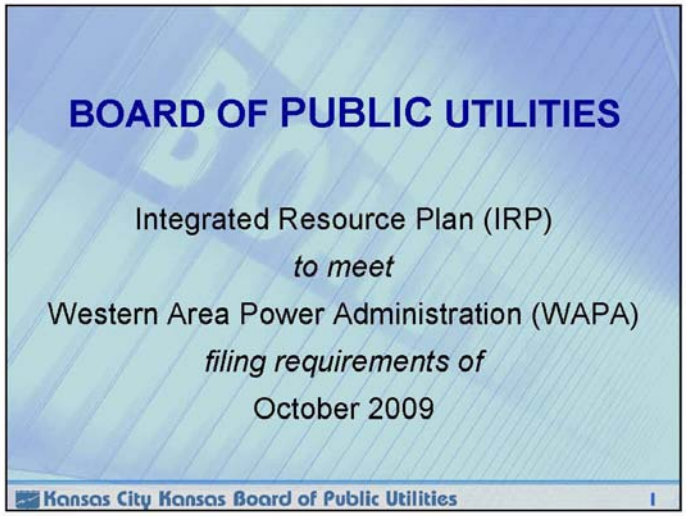
For additional questions regarding the draft 2009 IRP, please contact Blake Elliott at 913-573-6837.

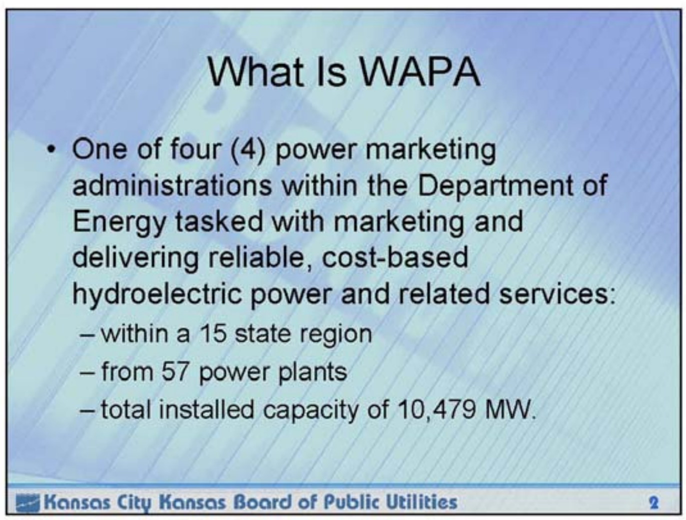
About BPU
BPU is a public utility that serves approximately 65,000 electric and 51,000 water customers, primarily in Wyandotte County, Kansas. The mission of the utility and its 640 employees is "to be the utility of choice and the workplace of choice, while improving the quality of life in the communities we serve." Go to www.bpu.com for more information.

# # #

Source URL:
http://pressreleases.kcstar.com/?q=node/54534

Exhibit A-6. Staff Presentation at the April 6, 2011 BPU Board Meeting.





What Is An IRP

- It is a planning tool that allows a utility to periodically revaluate how they are meeting their consumer's electrical needs
- WAPA introduces their IRP web page with the following statement:
  - "The IRP must evaluate the full range of alternatives to provide adequate and reliable service to a customer's electric consumers at the customer's or member's lowest system cost"

Why is an IRP needed ?

- Currently the BPU is purchasing 4.8 MW of capacity and about 14,900 MWH of energy from WAPA
  - WAPA capacity less than 1% of BPU's peak
  - BPU is a fraction of 1% of WAPA's total capacity
- Under the terms of the contract, BPU is required to submit a new IRP every five (5) years and annual progress reports.

WAPA's IRP Criteria

- Identify and compare of all practicable energy efficiency and energy supply resource options.
- Include action plan with timing set by customer. BPU
- Describe efforts to minimize adverse environmental effects of new resource acquisitions.
- Provide ample opportunity for full public participation.
- Conduct load forecasting.
- Include brief description of measurement strategies for options identified in IRP to determine whether objectives are being met.

Current Demand Side Programs

- **Heat Pump and Hot Water Rebate Program**.
  - Residential and Commercial customers given rebates to install or retro-fit energy efficient heat pumps or hot water heaters
  - Estimated summer peak load reduction = 1,500 kW
- **Signal Light Replacement Program**
  - Since December 2003, BPU has replaced incandescent signal lights with LED lamps at approximately 56 locations
  - Estimated annual energy savings = 137 homes
  - Estimated summer peak load reduction = 135 kW
- **Street Light Replacement Program**
  - Replacing Mercury Vapor lamps (MV) with more efficient High Pressure Sodium (HPS) lamps.
  - Estimated annual energy savings = 540 homes

BPU Collaborative Initiatives

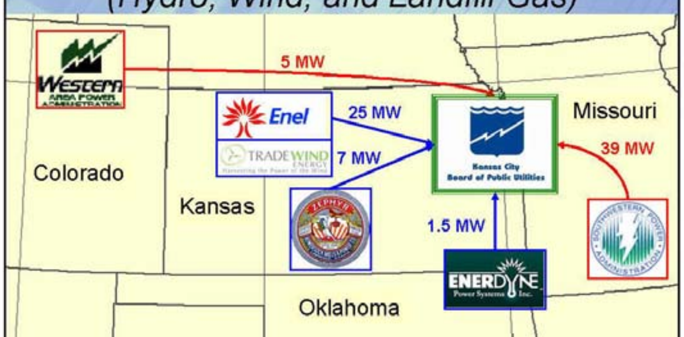
- Low income weatherization
- Energy Star appliance rebates
- Building Code updates
- Revolving Loan Program *(BPU Smart Homes)*
  - Efficiency Kansas
  - Kansas City, Kansas
  - BPU

425	Inquirys
191	Approvals
6	Loans Closed

Kansas City Kansas Board of Public Utilities 7

Diversified and Geographically Dispersed Renewable Energy Portfolio

(Hydro, Wind, and Landfill Gas)



Kansas City Kansas Board of Public Utilities 8

Renewable Energy Statistics

	SWPA	WAPA	Smoky Hills 2008	Oak Grove 2010	BMPC 2012
Capacity (MW)	38.6	4.8	25.2	1.5	7.0
Energy (MWhs)	92,640	14,900	94,923	11,826	27,594
Avg Res Cust	9,752	1,568	9,992	1,245	2,905
Cum Res Cust	9,752	11,320	21,312	22,557	25,461

- 80.5 MW of Renewable Capacity per Kansas Regs.
- 242,000 MWH clean energy annually
- 265,000 tons/yr CO_2 reduction clean energy purchases

- 25,461 Residential customers Renewable
- 577 Residential customers Energy Efficiency
- 26,038 Residential customers Total about 45%

IRP Action Plan

- Continue existing programs *(heat pump rebate, street light & signal light)*
- Continue evaluating demand side *(load curtailment and set back thermostats)*
- Continue evaluating supply side *(renewable energy and excess capacity of neighboring utilities)*
- Evaluate all opportunities for economic and environmental benefits and incorporate those plans that benefit BPU and its Customers
- Report studies to WAPA in BPU's Annual Update

Appendices

A. Record of the Public Comments
B. Load Forecast
C. TradeWind Energy Wind Analysis
D. Electric Master Plan Review - 2005
   – Coal Plant
E. Ten Year Power Supply Study – 2008
   – Gas Plant

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Public Comment Period

Proceedings Are Recorded

- Spoken Comments:
  - Sign up sheet for comments
  - Come to the podium
  - State your name and home address
  - State the name of any organization you represent
  - Make comments to the Board (3-5 minutes)
- Written Comments:
  - Submit to secretary tonight
  - Email belliott@bpu.com by midnight April 17th

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After Public Comment Period

- BPU staff will incorporate any changes warranted in the Draft IRP as well as incorporate the record of all Public Comments into Appendix A of the Document.
- Submit Final IRP to WAPA by April 30th
- If Accepted by WAPA it will be posted on WAPA and BPU website.

Kansas City Kansas Board of Public Utilities 13

THANK YOU

Blake Elliott
Director of Electric Supply Planning
Board of Public Utilities
belliott@bpu.com

Kansas City Kansas Board of Public Utilities 14

Appendix B

LOAD FORECAST

KANSAS CITY, KANSAS, BOARD OF PUBLIC UTILITIES
LOAD FORECAST

I. BPU SYSTEM LOAD FORECAST

A. Introduction

The Board of Public Utilities updates its electric load forecast on an ongoing basis. Short–term peak demand energy forecasts are developed for use in revenue forecasting and budgeting. Long–term energy and peak demand forecasts are developed for use in longer term system planning such as to assess the long-term energy and demand requirements of the BPU and for use in performing analyses of various capacity and/or energy purchase options.

B. Methodology

BPU's forecasting method is a bottom-up approach developed by aggregating customer class specific forecasts. Developing customer class specific forecasts allows for the ability to get a refined estimate of total system demand. The estimates for the individual customer classes are aggregated to develop the estimate for the entire system as a whole. In using this method, the forecast for the system as a whole is typically more accurate since it allows for careful consideration of the change in demand for each of the customer classes and then combining these carefully considered estimates rather than merely making one large system forecast estimate which may not as thoroughly consider all of the factors causing both the change in number of customers in each class and the use per customer of each individual customer class.

Customer class-specific forecast models of the energy requirements are developed utilizing forecasting software. Individual energy sales forecast models were prepared for each of the three largest customer classes, which are industrial, commercial, and residential, using the Smart Forecast software. The forecast models are based on historical and projected future customer class–specific energy requirements. The historical data for the years 1989 through 2009 were used. The twenty years forecasted are 2010 through 2029. Below are graphs and output of the industrial, commercial, and residential class data. No future major industrial customers have been added beyond the existing known customers.

C. Forecast Results

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are shown graphically in Figures 1 through 3 below.

Figure 1
Industrial Forecast

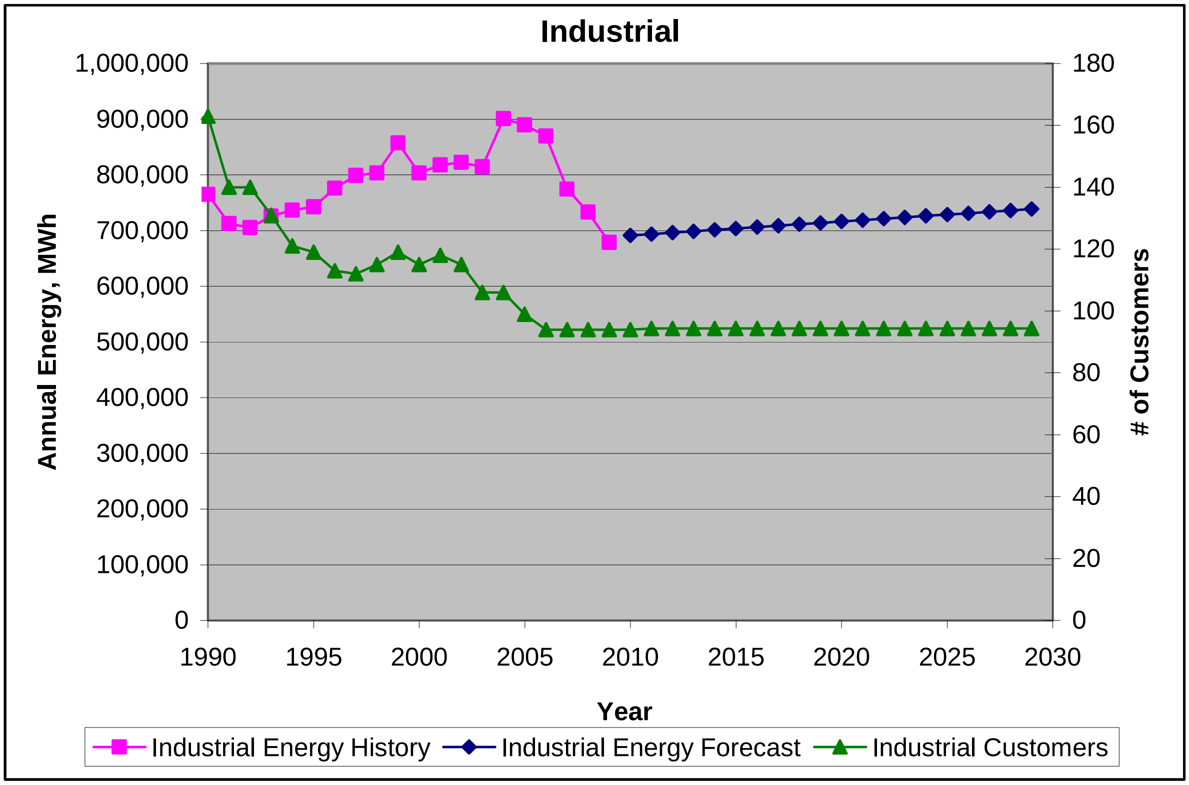


Figure 2
Commercial Forecast

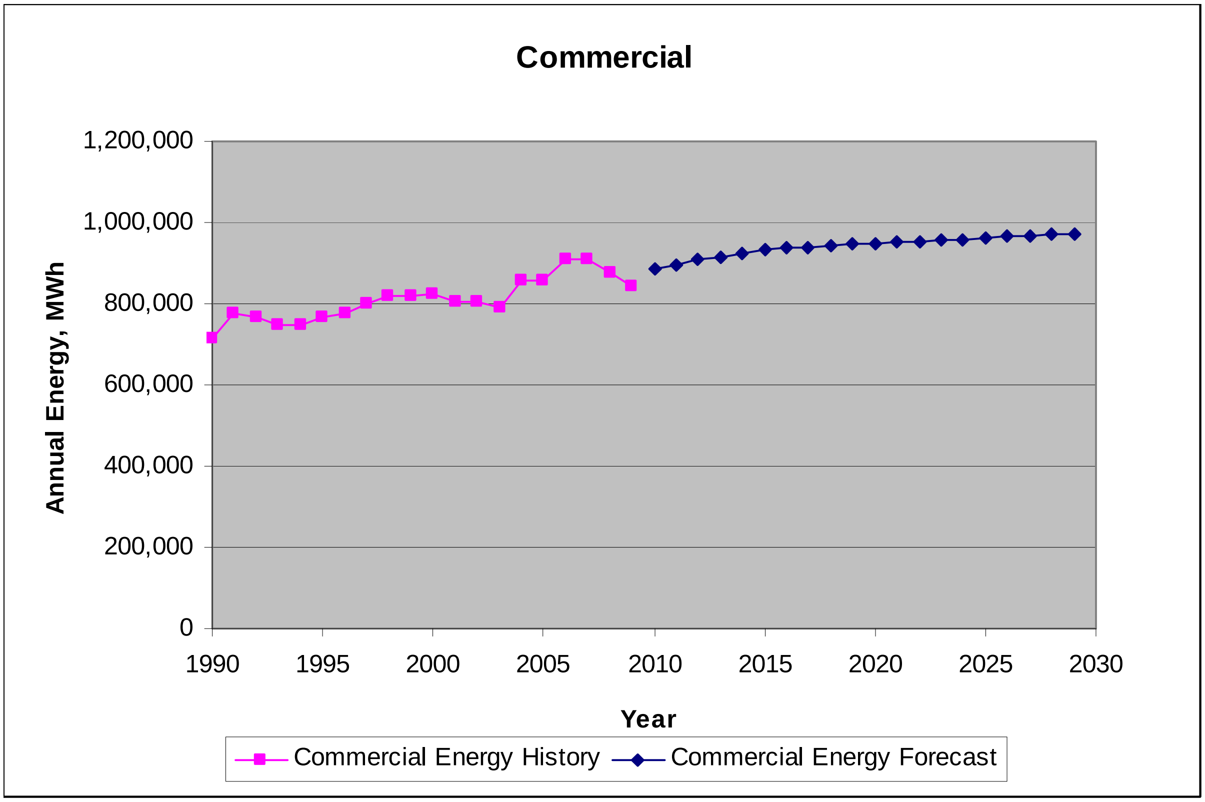
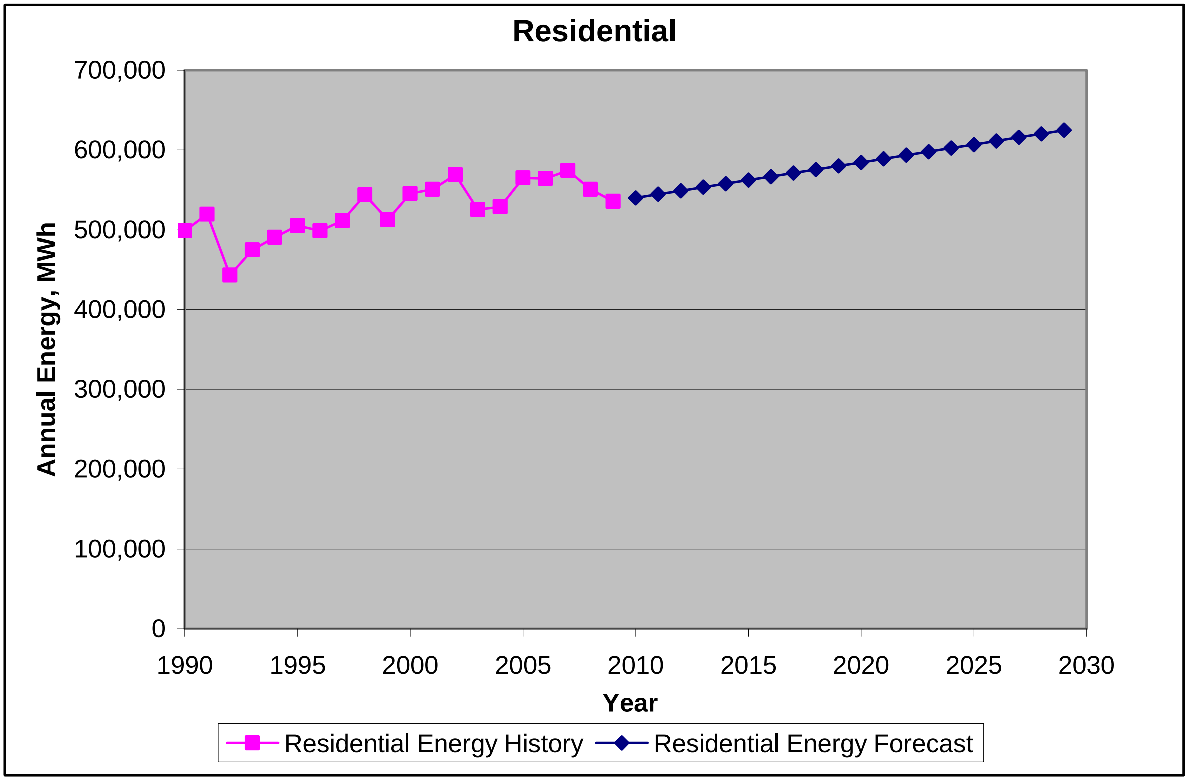


Figure 3
Residential Forecast



D. Major Customer Class Historical and Forecast Demand

The individual historical data and forecasts for industrial, commercial, and residential energy consumption are aggregated in the Table 1 on the next page. Aggregated into the Commercial customer class forecast is a forecast of the demand of the developing Village West shopping and entertainment area that was started in 2002. The Village West development includes the International Speedway, the Legends shopping center, dining and entertainment establishments, large retail establishments, and lodging facilities. It is experiencing continued growth in retail shopping and entertainment venues. There is a major league soccer stadium under construction and an announced large office building to be built in the District. Estimates for impact on electric demand of the continued development of the Village West District in western Wyandotte County, has been phased in through 2015.

Table 1

Historical and Forecast Annual Major Customer Class Data (MWh)

Year	INDUSTRIAL	Percent Change	COMMERICAL	Percent Change	RESIDENTIAL	Percent Change	Customer Classes Summed	Percent Change
1994	*736,222*		*749,647*		*490,565*		*1,976,434*	
1995	*742,405*		*766,786*		*505,071*		*2,014,262*	
1996	*776,176*		*775,978*		*498,538*		*2,050,692*	
1997	*798,688*		*800,422*		*511,299*		*2,110,409*	
1998	*803,312*		*820,089*		*543,913*		*2,167,314*	
1999	*857,643*		*821,146*		*512,422*		*2,191,211*	
2000	*803,137*		*822,627*		*545,308*		*2,171,072*	
2001	*817,759*		*802,679*		*550,869*		*2,171,307*	
2002	*822,336*		*802,521*		*568,701*		*2,193,558*	
2003	*814,756*		*791,141*		*525,369*		*2,131,266*	
2004	*900,749*		*856,716*		*528,738*		*2,286,203*	
2005	*889,595*		*856,388*		*564,945*		*2,310,928*	
2006	*869,656*		*909,405*		*564,353*		*2,343,414*	
2007	*774,212*		*909,220*		*574,127*		*2,257,559*	
2008	*733,053*		*877,656*		*550,774*		*2,161,483*	
2009	*678,327*		*843,232*		*535,690*		*2,057,249*	
2010	691,383	1.9%	884,401	4.9%	540,063	0.8%	*2,115,847*	2.85%
2011	693,870	0.4%	897,067	1.4%	544,471	0.8%	*2,135,408*	0.92%
2012	696,357	0.4%	910,180	1.5%	548,893	0.8%	*2,155,430*	0.94%
2013	698,844	0.4%	912,980	0.3%	553,316	0.8%	*2,165,140*	0.45%
2014	701,331	0.4%	923,404	1.1%	557,752	0.8%	*2,182,487*	0.80%
2015	703,818	0.4%	934,275	1.2%	562,194	0.8%	*2,200,287*	0.82%
2016	706,305	0.4%	937,075	0.3%	566,636	0.8%	*2,210,016*	0.44%
2017	708,792	0.4%	939,876	0.3%	571,089	0.8%	*2,219,757*	0.44%
2018	711,279	0.4%	942,676	0.3%	575,541	0.8%	*2,229,496*	0.44%
2019	713,766	0.3%	945,477	0.3%	580,003	0.8%	*2,239,246*	0.44%
2020	716,253	0.3%	948,277	0.3%	584,464	0.8%	*2,248,994*	0.44%
2021	718,740	0.3%	951,077	0.3%	588,933	0.8%	*2,258,750*	0.43%
2022	721,227	0.3%	953,877	0.3%	593,406	0.8%	*2,268,510*	0.43%
2023	723,714	0.3%	956,678	0.3%	597,877	0.8%	*2,278,269*	0.43%
2024	726,201	0.3%	959,478	0.3%	602,356	0.7%	*2,288,035*	0.43%
2025	728,688	0.3%	962,279	0.3%	606,833	0.7%	*2,297,800*	0.43%
2026	731,175	0.3%	965,079	0.3%	611,317	0.7%	*2,307,571*	0.43%
2027	733,662	0.3%	967,879	0.3%	615,798	0.7%	*2,317,339*	0.42%
2028	736,149	0.3%	970,680	0.3%	620,287	0.7%	*2,327,116*	0.42%
2029	738,636	0.3%	973,480	0.3%	624,778	0.7%	*2,336,894*	0.42%

The major customer classes' aggregate number is added to the smaller customer classes' energy forecasts. The smaller customer classes are: schools, local government, highway lighting, and metered and un-metered city government, BPU interdepartmental and borderline customers. Borderline customers' demand is served by BPU through a neighboring utility's distribution system. The customers are billed through the neighboring utility's billing system and BPU is paid by the neighboring utility. The table of historical and forecasted data of the small customer class data appears on the next page.

Table 2
Smaller Customer Class Data

MW-h

Year	SCHOOLS	HIGHWAY LIGHTING	COUNTY	Metered City of KCK	Unmetered City of KCK	BPU Inter-department	Borderline	Total
1996							13,893	
1997							14,967	
1998	53,842	3,380	9,247	34,986			15,525	
1999	51,810	2,972	8,911	35,355			13,926	
2000	55,483	2,962	9,380	38,029	34,930	29,600	16,875	187,258
2001	60,838	2,969	9,901	35,290	34,960	33,240	16,882	194,080
2002	63,612	2,973	7,872	34,794	35,181	41,911	18,221	204,565
2003	69,516	3,072	8,621	35,052	35,663	31,387	17,338	200,651
2004	68,938	2,666	8,438	33,678	36,042	46,563	17,806	214,130
2005	68,272	2,666	8,757	33,407	44,998	47,627	18,766	224,492
2006	70,867	2,666	8,782	34,428	36,783	44,613	18,679	216,818
2007	75,578	2,664	8,663	30,523	38,716	44,984	19,314	220,442
2008	75,240	2,646	7,864	36,320	37,425	45,882	18,483	223,860
2009	78,382	2,345	7,637	33,104	37,434	35,386	18,430	212,717
2010	80,987	2,552	8,055	33,322	37,864	42,090	18,742	223,612
2011	83,251	2,552	8,055	33,322	37,864	42,511	18,883	226,438
2012	85,516	2,552	8,055	33,322	37,864	42,936	19,024	229,269
2013	87,781	2,552	8,055	33,322	37,864	43,366	19,167	232,106
2014	90,045	2,552	8,055	33,322	37,864	43,799	19,311	234,948
2015	92,310	2,552	8,055	33,322	37,864	44,237	19,456	237,795
2016	94,575	2,552	8,055	33,322	37,864	44,680	19,602	240,648
2017	96,839	2,552	8,055	33,322	37,864	45,126	19,749	243,507
2018	99,104	2,552	8,055	33,322	37,864	45,578	19,897	246,371
2019	101,369	2,552	8,055	33,322	37,864	46,033	20,046	249,241
2020	103,633	2,552	8,055	33,322	37,864	46,494	20,196	252,116
2021	105,898	2,552	8,055	33,322	37,864	46,959	20,348	254,997
2022	108,163	2,552	8,055	33,322	37,864	47,428	20,500	257,884
2023	110,428	2,552	8,055	33,322	37,864	47,903	20,654	260,777
2024	112,692	2,552	8,055	33,322	37,864	48,382	20,809	263,675
2025	114,957	2,552	8,055	33,322	37,864	48,865	20,965	266,580
2026	117,222	2,552	8,055	33,322	37,864	49,354	21,122	269,491
2027	119,486	2,552	8,055	33,322	37,864	49,848	21,281	272,407
2028	121,751	2,552	8,055	33,322	37,864	50,346	21,440	275,330
2029	124,016	2,552	8,055	33,322	37,864	50,850	21,601	278,259

The aggregated system net is compared to monthly historical system net to allow for some weather normalization smoothing effect.

E. Losses

Losses are estimated based on component losses for transmission, primary, and secondary loads. These loss estimates are applied by customer class as annotated below.

Table 3
LOSSES

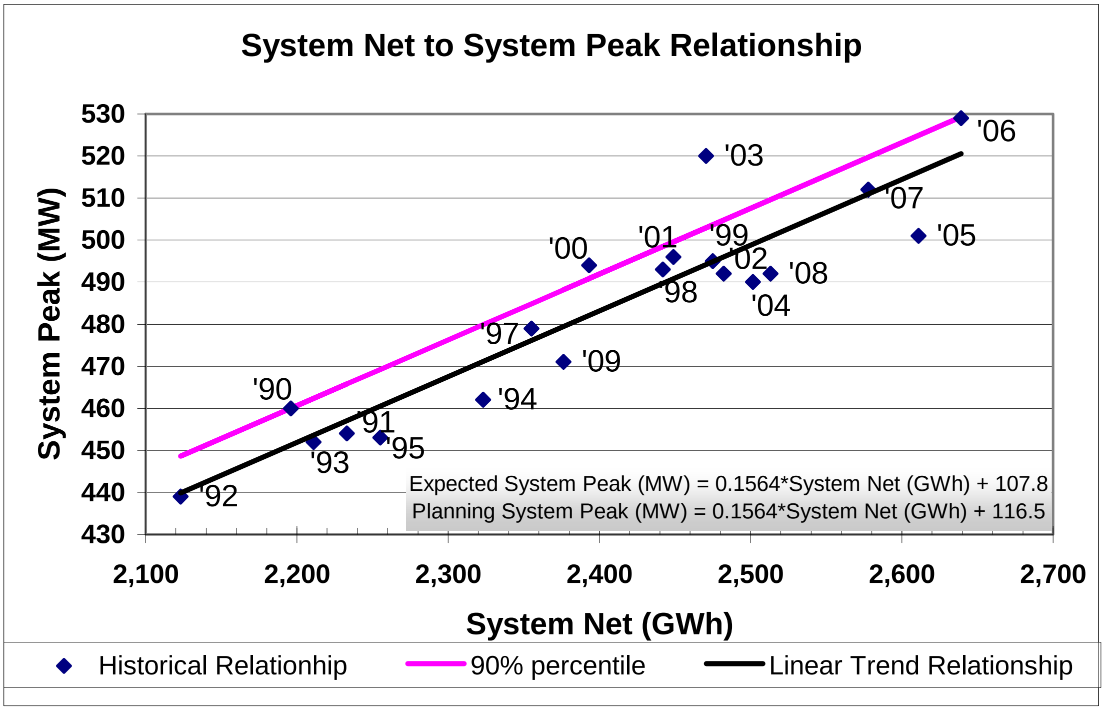
Customer Class	Losses Transmission 0.44%	Primary 2.39%	Secondary 4.38%
Industrial	X		
Commercial	X	X	X
Village West	X	X	X
Residential	X	X	X
Schools	X	X	X
Hiway Lighting	X	X	X
County	X	X	X
Metered City of KCK	X	X	X
Unmetered City of KCK	X	X	X
BPU Inter-Departmental	X	X	X
Borderline	X	X	
Nearman Participating	X		
Wholesale	X		

Based on loss study completed November 2002 and adjusted for historical trends since the study was completed.

F. Peak System Demand

Peak system demand is calculated based on linear regression trend modeling of the historical peak plotted against the associated system net for the years 1990 through 2009. Figure 4 contains a plot of the system annual net energy and system annual peak demand. The black line in Figure 4 shows the historical trend line relationship between system annual net energy and system annual peak demand. The magenta line is drawn to represent the system net to system peak relationship that will result in a calculated peak equal to or greater than the actual peak 90% of the years used for the analysis.

Figure 4



In addition to its retail load responsibilities, the BPU has wholesale power supply contracts with the Kansas Municipal Energy Agency (KMEA) through 2021 and the City of Columbia, Missouri (Columbia) through 2022, based on their participation in BPU's Nearman Unit No. 1. Forecasts for energy sales to these off-system Nearman participation customers were calculated as the average of the last seven years sales to these participants, which is slightly lower than the average of the last three years. Recent Nearman Participating historical data and forecast energy appears in the table below:

Table 4
NEARMAN PARTICIPATING ENERGY

Year	Nearman Participating Energy (kWh)
2005	*313,903,000*
2006	*342,056,000*
2007	*377,888,000*
2008	*332,427,000*
2009	*434,356,000*
2010	398,063,000
2011	262,441,000
2012	351,590,571
2013	351,590,571
2014	351,590,571
2015	351,590,571
2016	351,590,571

The aggregate peak for Nearman Participants is 58MW, which is the sum of the KMEA and Columbia contract amounts. The historical energy varies from year to year. The energy is forecasted at about 352 GWh/year.

G. Forecast Results

The system load forecast developed by the BPU is shown in Table 5. The forecast includes sales to BPU's retail customers, borderline, city, BPU interdepartmental and losses. It does not include Nearman Participation customer sales or opportunity sales to the wholesale spot market.

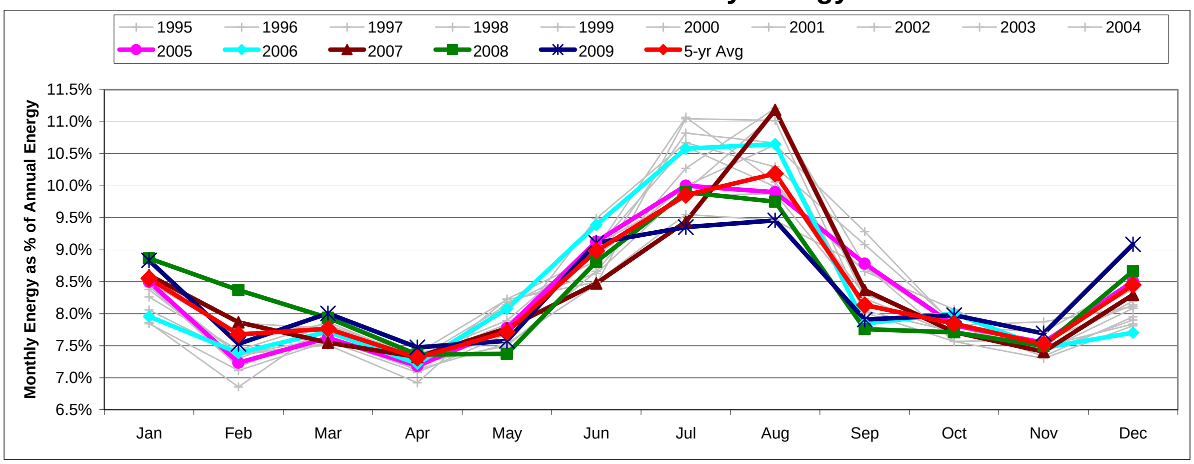
Table 5
Load Forecast

Year	System Net Peak Demand (MW)	System Net Total Energy (GWh)	Growth (%)	Load Factor (%)
2004	490	2,519		58.7
2005	501	2,630	4.39	59.9
2006	529	2,658	1.07	57.4
2007	512	2,597	-2.29	57.9
2008	492	2,532	-2.52	58.7
2009	471	2,393	-5.49	58.0
2010	489	2,459	2.79	57.4
2011	493	2,483	0.95	57.5
2012	497	2,507	0.96	57.6
2013	499	2,519	0.51	57.7
2014	502	2,540	0.84	57.8
2015	505	2,562	0.85	57.9
2016	507	2,575	0.50	57.9
2017	509	2,588	0.50	58.0
2018	511	2,601	0.50	58.1
2019	513	2,613	0.50	58.1
2020	515	2,626	0.49	58.2
2021	517	2,639	0.49	58.2
2022	519	2,652	0.49	58.3
2023	521	2,665	0.49	58.4
2024	523	2,678	0.48	58.4
2025	525	2,691	0.48	58.5
2026	527	2,704	0.48	58.5
2027	529	2,717	0.48	58.6
2028	531	2,730	0.48	58.6
2029	533	2,742	0.47	58.7

BPU's base energy requirements are projected to grow at an average annual rate of about 1.5% over the next three years before leveling off at about a 0.5% per year average annual growth rate.

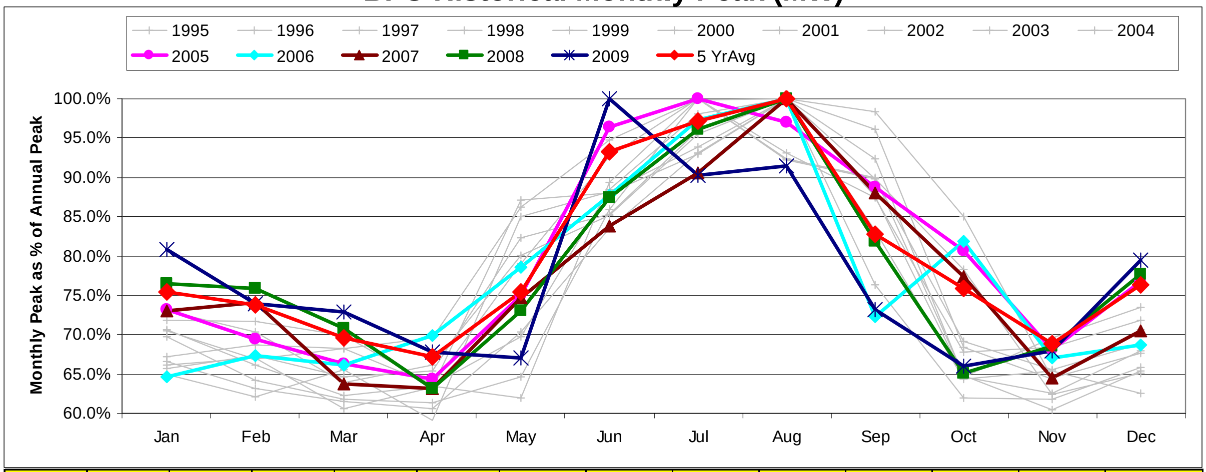
Monthly historical data from 1995 through 2009 was used to allocate energy and peak to each month. A percentage of average monthly system net is used to spread forecasted energy between months in all forecasted years. A percentage of average monthly peak compared to the average annual peak is used to determine monthly peak in all forecasted years. The data tables and graphs appear below:

Figure 5
BPU Historical Monthly Energy



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1995	8.38%	7.30%	7.83%	7.23%	7.50%	8.66%	10.27%	11.21%	8.24%	7.68%	7.58%	8.14%
1996	8.49%	7.68%	7.83%	7.32%	7.90%	9.08%	9.85%	9.88%	8.17%	7.82%	7.88%	8.11%
1997	8.47%	7.36%	7.54%	7.40%	7.57%	9.03%	10.61%	9.99%	8.66%	8.07%	7.41%	7.90%
1998	7.86%	6.86%	7.83%	7.10%	8.23%	8.90%	9.99%	10.64%	9.28%	7.82%	7.41%	8.08%
1999	8.43%	7.17%	7.72%	7.29%	7.84%	9.01%	11.07%	10.06%	8.30%	7.82%	7.33%	7.95%
2000	8.06%	7.36%	7.51%	6.92%	8.18%	8.63%	9.92%	11.12%	8.75%	7.57%	7.59%	8.38%
2001	8.26%	7.43%	7.87%	7.29%	8.14%	8.82%	10.82%	10.66%	8.02%	7.57%	7.30%	7.81%
2002	7.85%	7.11%	7.57%	7.08%	7.68%	9.48%	10.67%	10.29%	9.08%	7.85%	7.49%	7.84%
2003	8.42%	7.37%	7.61%	7.13%	7.53%	8.46%	11.05%	11.02%	8.05%	7.72%	7.46%	8.20%
2004	8.53%	7.85%	7.77%	7.39%	8.22%	8.49%	9.55%	9.46%	8.71%	7.80%	7.71%	8.51%
2005	8.50%	7.23%	7.62%	7.18%	7.77%	9.13%	10.00%	9.90%	8.78%	7.82%	7.55%	8.51%
2006	7.96%	7.39%	7.72%	7.22%	8.08%	9.39%	10.58%	10.65%	7.85%	8.00%	7.47%	7.70%
2007	8.60%	7.86%	7.55%	7.32%	7.77%	8.47%	9.44%	11.18%	8.37%	7.72%	7.41%	8.30%
2008	8.87%	8.37%	7.94%	7.36%	7.37%	8.81%	9.90%	9.75%	7.76%	7.71%	7.50%	8.66%
2009	8.83%	7.53%	8.00%	7.47%	7.58%	9.11%	9.35%	9.46%	7.91%	7.98%	7.69%	9.08%
5 YrAvg	8.55%	7.68%	7.77%	7.31%	7.72%	8.98%	9.85%	10.19%	8.13%	7.85%	7.52%	8.45%

Figure 6
BPU Historical Monthly Peak (MW)



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Peak MW
1995	70.42%	66.89%	68.21%	63.58%	69.76%	88.52%	98.01%	100.00%	89.85%	69.09%	65.56%	68.87%	453
1996	71.86%	71.65%	69.91%	63.64%	79.00%	92.64%	100.00%	93.07%	87.45%	67.75%	68.40%	71.86%	462
1997	70.56%	66.18%	62.21%	63.47%	62.00%	89.35%	100.00%	92.28%	89.77%	78.29%	62.42%	65.14%	479
1998	64.91%	62.07%	65.52%	59.03%	84.99%	88.24%	93.91%	100.00%	92.29%	64.71%	62.47%	67.95%	493
1999	69.70%	64.24%	61.82%	61.41%	64.65%	85.86%	100.00%	92.32%	89.90%	64.85%	60.40%	65.45%	495
2000	66.19%	67.00%	60.53%	63.36%	87.04%	88.06%	92.91%	100.00%	96.15%	68.42%	64.37%	70.65%	494
2001	65.73%	67.34%	64.72%	65.32%	82.26%	85.28%	95.97%	100.00%	83.27%	64.31%	65.32%	62.50%	496
2002	67.22%	68.68%	68.27%	69.52%	86.22%	94.78%	99.79%	100.00%	98.33%	84.97%	64.51%	67.64%	479
2003	66.54%	63.08%	61.54%	60.58%	70.38%	83.46%	93.08%	100.00%	76.35%	61.92%	61.73%	65.77%	520
2004	73.06%	70.41%	63.88%	66.12%	80.00%	85.10%	95.51%	100.00%	87.55%	64.69%	69.59%	73.47%	490
2005	73.25%	69.46%	66.27%	64.27%	75.05%	96.41%	100.00%	97.01%	88.82%	80.64%	68.06%	76.85%	501
2006	64.65%	67.30%	66.16%	69.94%	78.64%	87.71%	97.35%	100.00%	72.21%	81.85%	67.11%	68.62%	529
2007	73.05%	74.02%	63.67%	63.09%	74.61%	83.79%	90.63%	100.00%	88.09%	77.34%	64.45%	70.51%	512
2008	76.42%	75.81%	70.73%	63.21%	72.97%	87.40%	96.14%	100.00%	81.91%	65.04%	68.50%	77.64%	492
2009	80.89%	73.89%	72.82%	67.73%	67.09%	100.00%	90.23%	91.51%	73.25%	66.03%	67.94%	79.41%	471
5 YrAvg	73.65%	72.10%	67.93%	65.65%	73.67%	91.06%	94.87%	97.70%	80.86%	74.18%	67.21%	74.60%	501
Nrmlizd	75.38%	73.79%	69.53%	67.19%	75.40%	93.20%	97.10%	100.00%	82.76%	75.93%	68.79%	76.36%	501

Appendix C

TradeWind Energy Wind Proposal Analysis

TradeWind Energy presented BPU with a proposal to purchase wind generation from the Smoky Hills Wind site in central Kansas. This report discusses the computer production cost model simulations of the BPU system that were created to analyze the economics associated with the proposed wind generation and the results of the analysis.

The objective of the analysis reported here was to measure the benefit of subscribing to wind generation considering impacts of transmission curtailments resulting from not obtaining firm transmission from the Smoky Hills Wind Farm to the BPU service territory and the impact of high natural gas prices on the benefits of wind generation.

Much of the data used in the analysis is privileged and confidential information subject to confidential treatment in the proposed contract with TradeWind Energy. Do not release any information from this report without first contacting BPU legal counsel. This analysis was performed for internal decision making purposes only.

Calculation of Net Expected Economic Benefits

The cost/benefit analyses conducted in this study focused on marginal-cost based assessments with operating costs savings estimated over a 10 year period as is typical in the industry. The ten year savings based on the net present worth of the total production cost savings is used as the measure of a scenarios benefit.

Several scenarios using different transmission curtailment rates, natural gas price, and electricity price forecast assumptions were analyzed. Shown in Table 1 are the ten scenarios analyzed. The table's vertical and horizontal titles depict the varying scenario assumptions. The name of the scenario matching the criteria is at the intersection of the horizontal and vertical columns. For example, Wind-1a, shown at row 3, column 3, is the name of the scenario that models BPU's system with 25 MW wind generation, the alternate fuel and electricity price forecast and no transmission curtailment of the wind generation.

Table 1. Summary of Scenarios Analyzed.

Scenario Criteria	Expected Fuel & Electricity Price	Alternate Fuel & Electricity Price	High Fuel & Electricity Price
No Wind	Base	Base-Alt	Base-High
25 MW Wind with Normal Transmission Curtailment	Wind-1	Wind-1a	
25 MW Wind with No Transmission Curtailment	Wind-2	Wind-2a	Wind-4
25 MW Wind with High Transmission Curtailment	Wind-3	Wind-3a	

Summary descriptions of the scenarios modeled are:

1. Base – BPU's system without wind generation and using the expected fuel and electricity prices forecast.
2. Wind-1 – BPU's system with 25 MW wind generation using the expected fuel and electricity price forecast and normal transmission curtailment of the wind generation.
3. Wind-2 – BPU's system with 25 MW wind generation using the expected fuel and electricity price forecast and no transmission curtailment of the wind generation.
4. Wind-3 – BPU's system with 25 MW wind generation, expected fuel and electricity price forecast and high transmission curtailment rate of the wind generation.
5. Base-Alt – BPU's system without wind generation using the alternate fuel and electricity prices forecast describe below.
6. Wind-1a – BPU's system with 25 MW wind generation, an alternate fuel and electricity price forecast and normal wind generation transmission curtailment.
7. Wind-2a – BPU's system with 25 MW wind generation, an alternate fuel and electricity price forecast and no wind generation transmission curtailment.
8. Wind-3a – BPU's system with 25 MW wind generation, an alternate fuel and electricity price forecast and high wind generation transmission curtailment.
9. Base-High – BPU's system without wind generation using the high fuel and electricity prices forecast describe below.
10. Wind-4 – BPU's system with 25 MW wind generation, high natural gas and electricity price forecast and no wind generation transmission curtailment.

Model input assumptions and results of the simulations are presented in this report after the following section containing a short background summarizing the benefits and disadvantages of wind generation.

General Background on Wind Energy

Wind, and other renewable energy sources, can supplement a load serving entities generation and reduce the consumption of coal and other fossil fuels and the emissions resulting from those fuels. Additionally, laws passed in several states require that power producers generate part of their electricity from new renewable sources. It is expected that more states will pass laws requiring partial generation from renewable sources. Another reason for BPU to analyze the economics of wind is the anticipation that BPU's participation in a renewable energy project will be considered in the emissions permitting requirements for a new coal fueled unit. Additionally, when wind generation is available it can hedge potential high fuel costs associated with natural gas and fuel oil fired units.

However, generation from wind using current wind generation technology is neither constant nor consistent. Electric customers usually desire an electricity supply that is constant and consistent. Therefore, normally, wind turbines cannot be used to satisfy firm capacity requirements, so traditional demand response power stations will always be required to meet reliability requirements.

Figure 1 gives an indication of monthly and hourly variation of the wind generation. The graph shows the average expected percent of potential generation for each hour of the day for each month. The graph indicates that in the Smoky Hills wind farm area, it is expected that the generation from the wind farm will be least during the month of August. Expected wind generation during the day in August is expected to average between 25% and 30% of the subscribed capacity between 8:00 A.M and 5:00 P.M. Conversely, wind generation is expected to be at its maximum during the month of September when the capacity factor is expected to average about 48% during the same hours. Figure 2 shows the average variation of potential wind generation through the day considering all months of the year. This figure shows that the trend throughout the year of wind velocity increasing at night and decreasing during the day. Monthly expected capacity factors, considering all hours of the day are shown in Figure 3. Again, this figure shows that the maximum capacity factor is expected to occur during September and the lowest capacity factor is expected in August.

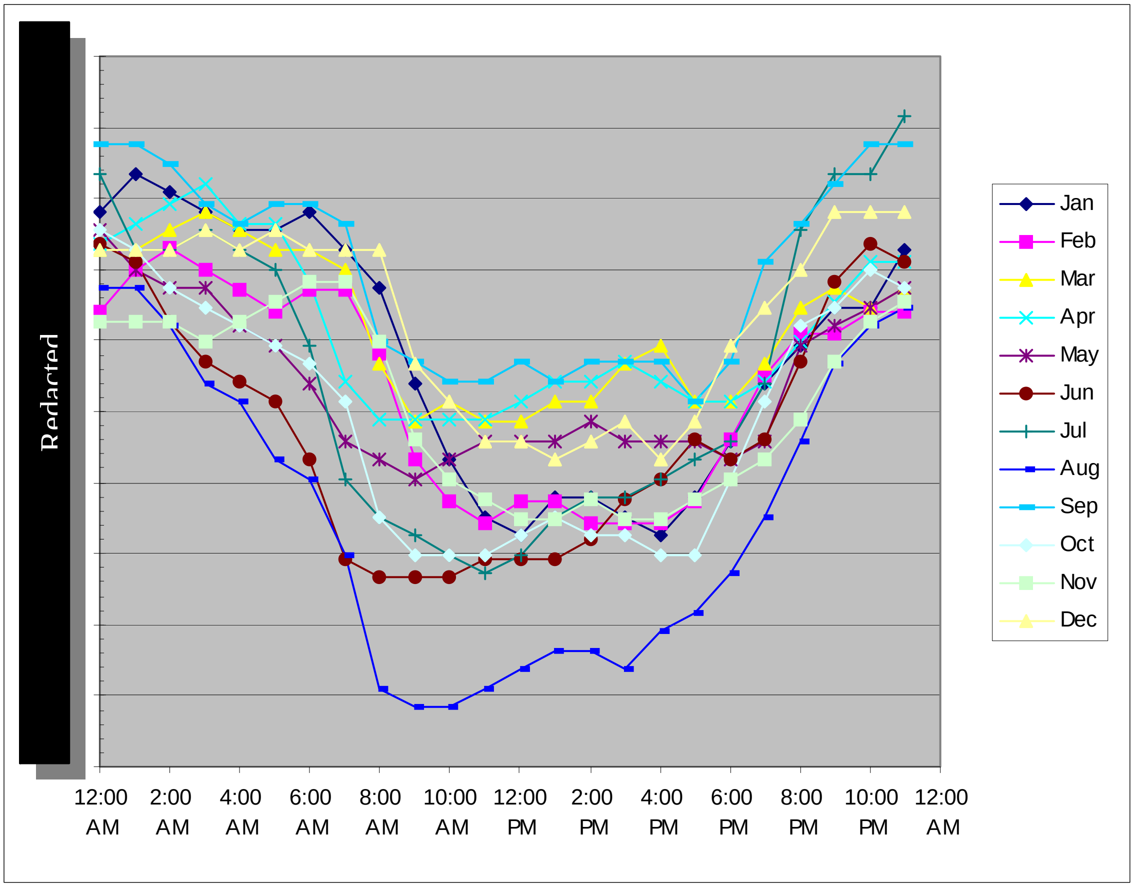


Figure 1. Predicted Wind Energy Variability by Month and Hour of Day.

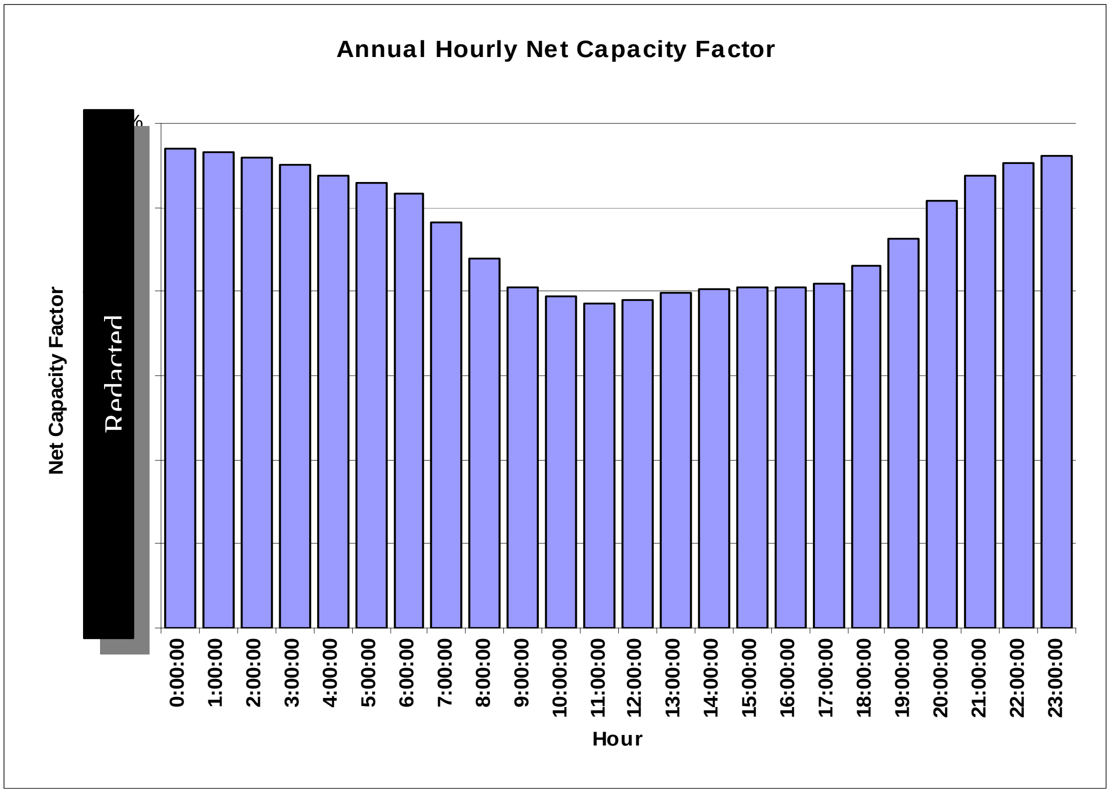


Figure 2. Expected wind generation hourly capacity factors.

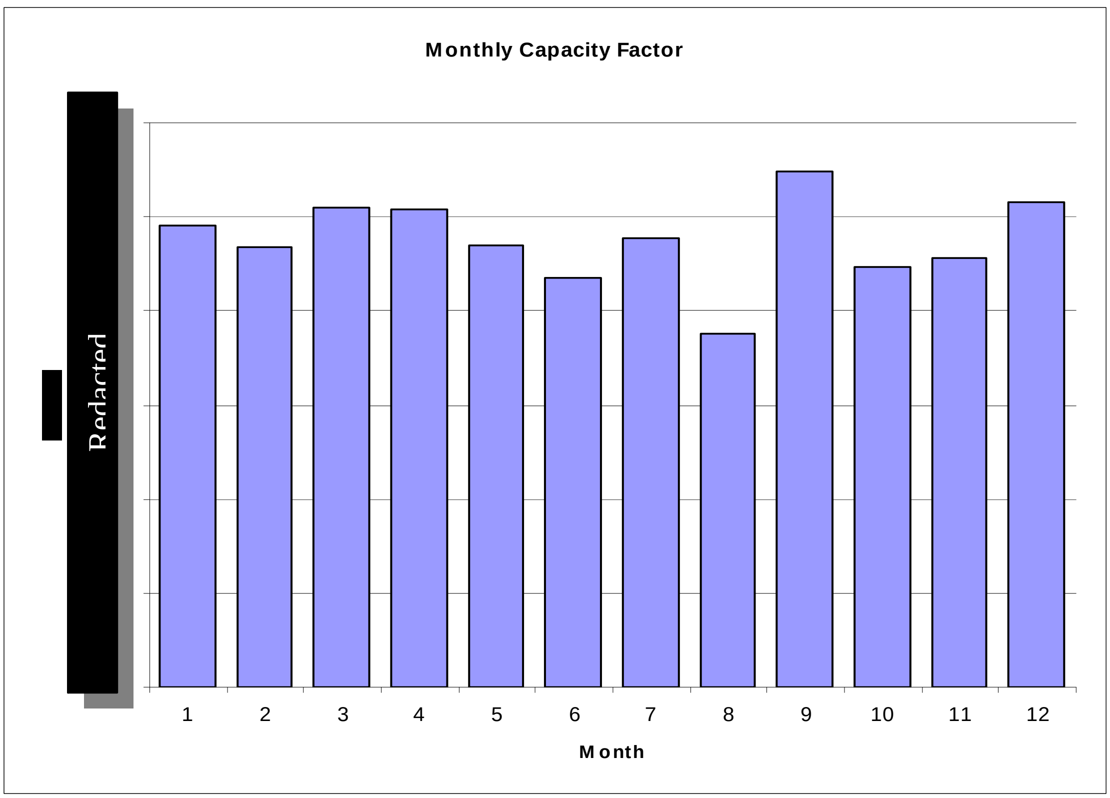


Figure 3. Expected monthly average capacity factors.

Wind Energy Cost

The wind energy cost most recently proposed by TradeWind Energy is \$43.20/MWh. The proposed price remains constant for 20 years, assumed to start in 2008.

Transmission Curtailments

Historical transmission loading relief events from beginning of year 1997 through mid-September 2006 were analyzed to estimate the rate at which wind generation at the Smoky Hill Wind Farm may be curtailed from obtaining transmission to the BPU service territory in the absence of firm transmission arrangements. It was assumed in the analysis that curtailed energy could be sold on the local market for \$35/MWh. Three separate curtailment scenarios were analyzed. One scenario assumes no transmission curtailment. The other two scenarios are described below.

An estimate of the worst case frequency of curtailment of energy from the wind farm for this analysis was based on the assumption that if two or more Transmission Loading Reliefs (TLRs) are in effect during an hour, then it is assumed that the wind generation from Smokey Hills would be curtailed. Figure 4 graphically depicts the results of this “2-or-more” criteria. The graph shows that during the months of July and August, about 70-80 percent of the time, two or more TLRs were in effect between the hours of 11:00 a.m. and 9:00 p.m. The other month that has relatively high TLR occurrences is June. This TLR analysis was used to specify the curtailment schedule for the wind generation. Table 2 shows the resulting random curtailment rate that was specified in the production cost model simulations.

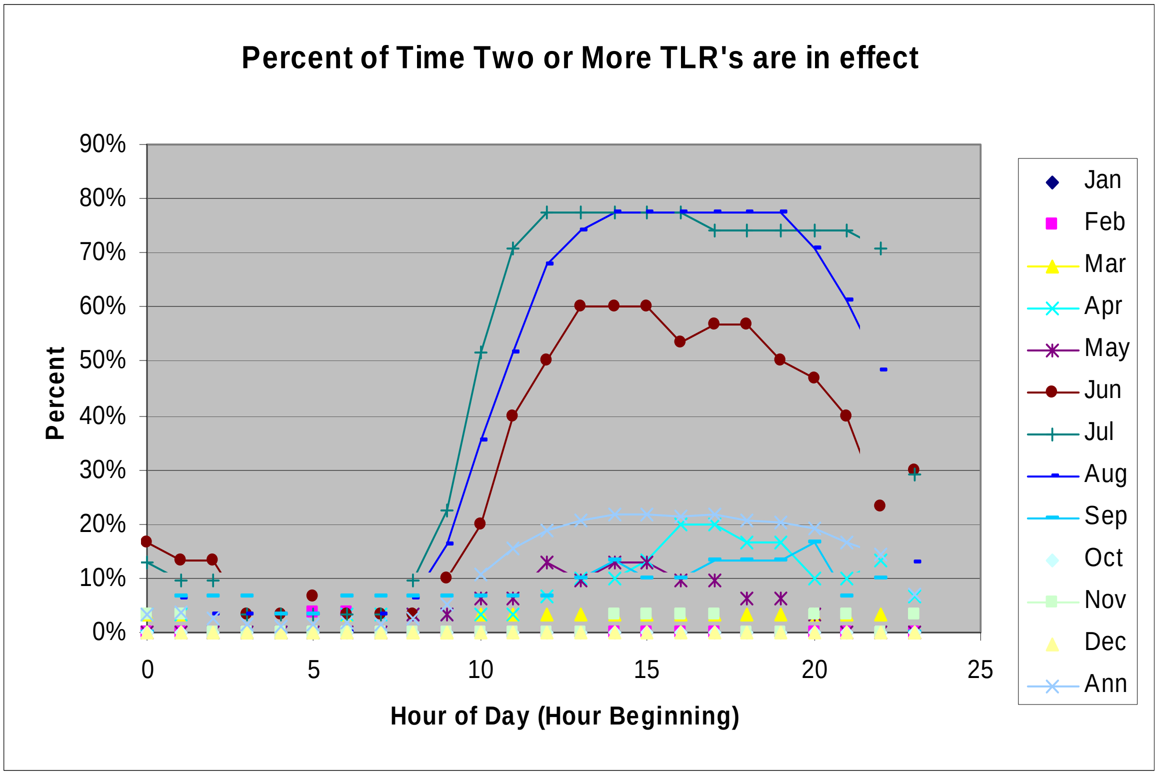


Figure 4. Percent of Time Two or More TLR's are in effect for SPP from Sep 2005 through Aug 2006.

Table 2. Curtailment Rate Using "2-or-more" Criteria.

Months	Curtailment Rate
Jan-May	2.6%
Jun-Aug	33.6%
Sep-Dec	2.0%
Annual	10.2%

Southwest Power Pool (SPP) personnel performed a PowerWorld Simulator solution of the transmission grid and looking at the Power Transfer Distribution Factors (PTDFs) for flows sourcing at Smokey Hills and sinking in KC area. The "normal" curtailment rate was derived from this solution. Table 3 below lists the flowgates impacted at 5% or more for Smokey Hills - KACY transfers using the latest Model Development Working Group (MDWG) 2008 power flow model. The same list of flowgates was affected for all four seasons. To simulate the Smoky Hills windfarm, a subsystem was added to the MDWG 2008 model for Smokey Hills per aggregate study data. The PTDFs were calculated using the methodology as is used for SPP's Available Flowgate Capability (AFC) process and the NERC Interchange Distribution Calculator (IDC) tool used to calculate TLR curtailments, to correspond with how schedules would be curtailed for TLR events (assuming Smokey Hills is its own subsystem). Non-SPP flowgates that were calculated are indicated within parentheses in Table 3.

Table 3. Affected Flowgates.

Smokey Hills - KACY	
FGNAME	Flowgate Name
COOPER_S	Cooper-St. Joseph 345 kV (MAPP)
GRIS_LNC	Grand Island (MAPP)
IATAN_STJOE	Iatan-St. Joseph 345 kV
SJHALKNAIASC	St. Joe-Hawthorn 345 kV
STIANTLACWGR	Stilwell-Antioch 161 kV
STIREDSTIPEC	Stilwell-Redel 161 kV

The list of flowgates identified as a result of the load flow analysis was cross-referenced with the Septermber 2005 to August 2006 TLR events to determine the percent of time that one or more of the identified flowgates were experiencing a TLR. From this information the curtailment rate schedule shown in Table 2 was determined and used in the analysis for the base curtailment rate.

Table 4. Curtailment Rate Using

"TDF" Criteria.

Months	Curtailment Rate
Jan-May	0.07%
Jun-Sep	1.0%
Oct-Dec	0.07%
Annual	0.3%

Natural Gas Price Forecast

Natural gas prices can have a significant impact on the benefit of subscribing to wind generation. The expected natural gas price and electric market price forecasts used in this analysis is derived from the Global Energy Decisions Power Market Advisory Service Electricity & Fuel Price Outlook – Midwest Fall 2006 expected forecast. The high natural gas price and electric market price forecasts are derived from the high forecast of the same document. The alternate natural gas price and electric market price forecasts used in this analysis is derived from the Global Energy Decisions Power Market Advisory Service Electricity & Fuel Price Outlook – Midwest Spring 2006 expected forecast. The fall 2006 expected case natural gas price forecast for the southern star pipeline is shown in Figure 5 in $2006. In addition to the fall 2006 expected forecast, the spring 2006 expected forecast and the fall 2006 high forecasts as received from Global Energy Decisions (GED), are shown in in $2006.

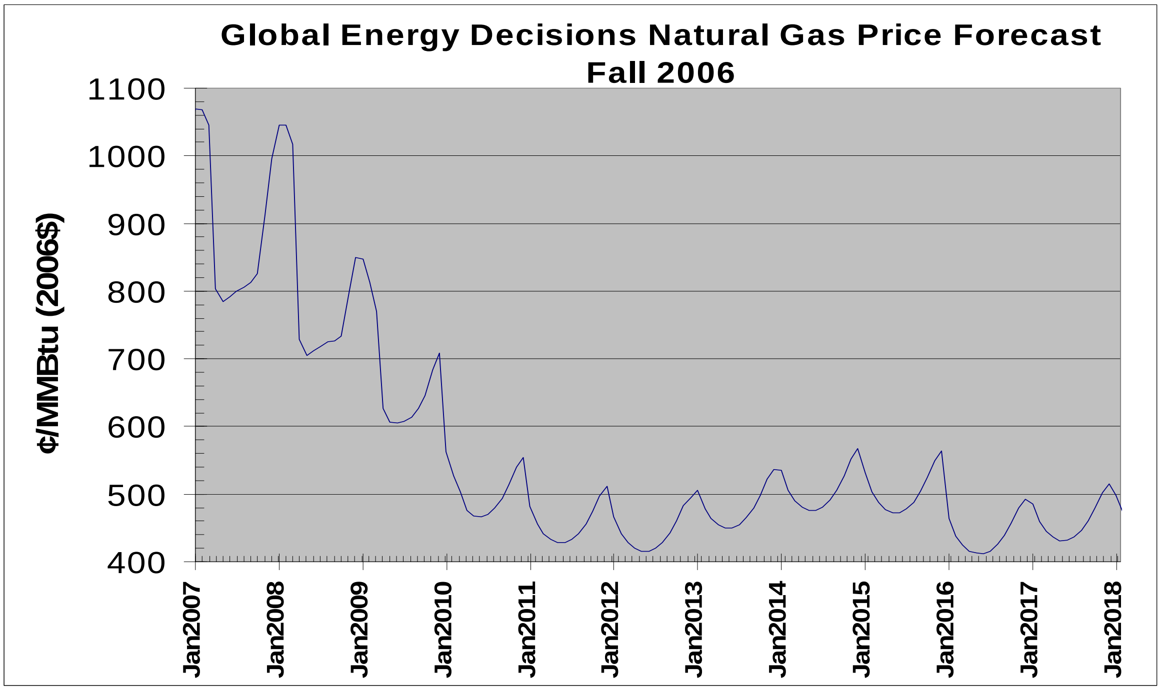


Figure 5. Global Energy Decisions Fall 2006 Natural Gas Price Forecast for the Southern Star Pipeline.

In addition to the expected case natural gas price forecast, the high natural gas price forecast sensitivity from the GED fall 2006 forecast was used in one of the scenarios analyzed.

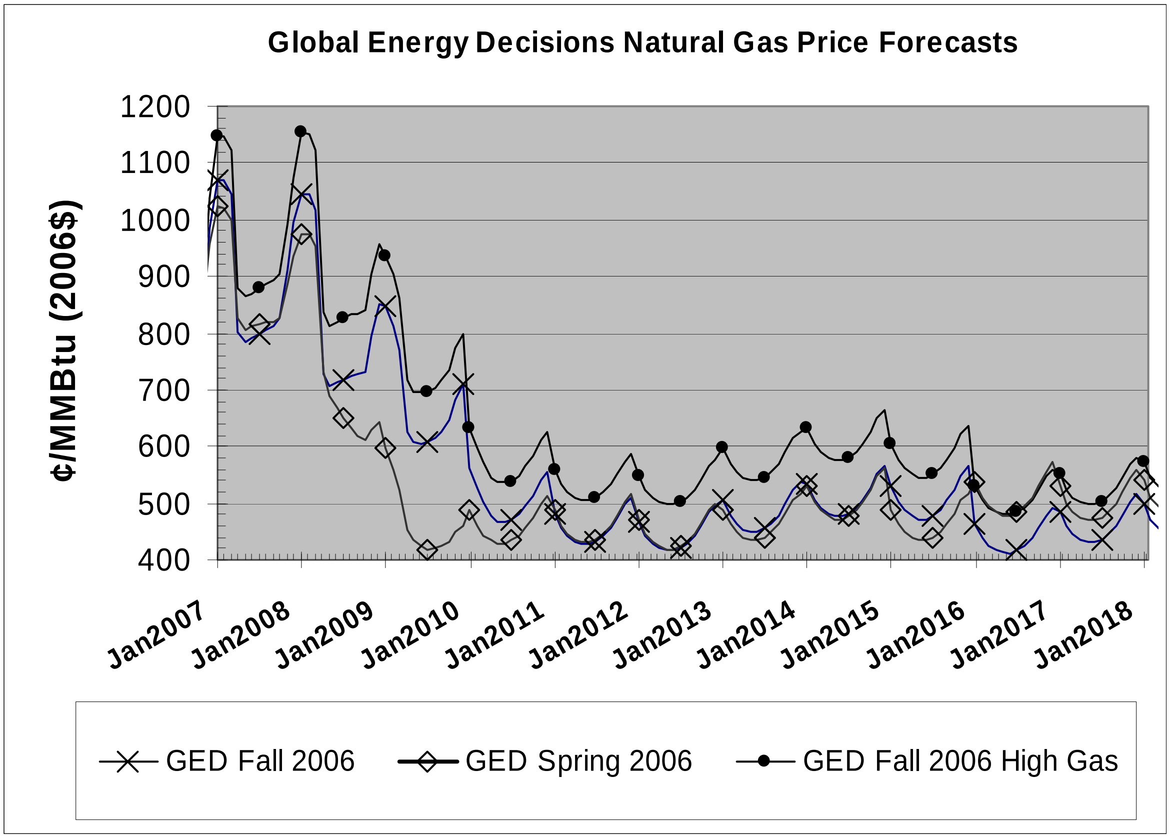


Figure 6. Global Energy Decisions Fall 2006 and Spring 2006 Natural Gas Price Forecasts for the Southern Star Pipeline.

Electric Market Spot Price

The spot market electricity prices expected and high forecasts are derived from the *Global Energy Decisions Power Market Advisory Service Electricity & Fuel Price Outlook – Midwest Fall 2006* expected and high forecasts and the alternate spot market electricity prices forecast from the Spring 2006 expected forecast for the North Southwest Power Pool Region (SPPN). The forecast as received from Global Energy Decisions (GED) is in $2006. The forecast was adjusted by the forecast CPI to develop nominal year prices

Transmission Costs

An SPP oasis price query was conducted to get an estimate of transmission charges associated with the transmission of the wind generation to the BPU service territory. The estimated transmission cost includes both a capacity component and an energy component. The capacity charge estimate is $916.40/MW-month ($2006) developed from a WR-KACY SPP Oasis price query tariff. The capacity charge estimate is the aggregate of a $705.50/MW-month zonal non-firm tariff ($830/MW-month with a 15% SPP non-firm discount), a $59.28/MW-month schedule fee, and a $116.48/MW-month administration fee. The capacity charge was escalated at 2% per year. The energy component cost, to account for losses, is $1.12/MWh, $2006, also escalating 2% per year.

Renewable Energy Credit

A renewable energy credit (REC) of $3.00/MWh in 2008 is assumed. The REC is escalated at 2% per year.

Results Summary

The results of the Wind analysis show that with the REC credit, there is cost savings associated with purchasing wind energy under all scenarios analyzed at a 25 MW capacity. The production cost simulations to analyze the wind generation alternatives were based on BPU's existing generation portfolio and the addition of 135 MW of a 235 MW Nearman 2 unit in 2012 and the retirement of Quindaro CT1 in 2015.

Table 5 and Table 6 show the results of the production cost model simulations. In Table 5, which shows the total production costs, the first column, titled ‘No Wind’, shows the expected case assumptions without the 25 MW Smoky Hills wind generation with expected natural gas and spot market electricity prices. Ten year total cumulative net present value cost are shown following the annual numbers. The average annual cost is shown below the cumulative values. The annual cost from this no wind scenario was compared to three different curtailment assumptions. The annual cost numbers under the Wind-1, Wind-2, and Wind-3 columns show annual cost estimates assuming base curtailment, no curtailment, and high curtailment scenarios, respectively (see key legend at bottom of table). Table 6 show the net benefit of the various wind scenarios. The table shows the annual cost savings associated with the wind generation as the difference between total production costs with and without the 25 MW of wind generation. The first row of cumulative present worth values shown are without REC. The expected annual REC are shown in the right column of the Net Benefit section. Adding the REC to the net benefit values result in the net benefit values shown at the bottom of the table.

The Cumulative Present Worth (CPW) benefit of the wind scenarios is calculated using discount rate of 5.75%. The top CPW row of the table shows that without REC credits under the no and base curtailment assumptions, there is about $800,000 10-year net benefit in subscribing to the wind generation. If the estimated CPW of REC is added to the net benefit CPW, the estimated total net benefit CPW increases to about $3,000,000 for the 10-year study horizon. The high curtailment scenario has slightly higher CPW cost (lower net benefit) than the no wind scenario without REC, but with the expected REC added in, it has a net benefit over ten years of about $2,000,000.

A high natural gas and resulting spot market price scenario was also analyzed to demonstrate the added benefit of wind generation when natural gas prices rise. The results of the high natural gas price show an additional average discounted net benefit of $181,000/yr over the ten year horizon.

To further demonstrate that natural gas prices heavily influence the profitability of the wind project, the spring 2006 price forecast from GED was used under the three curtailment scenarios. The spring 2006 issue of the natural gas price forecast was lower than the fall 2006 forecast in the 2007-2011 timeframe. The lower gas price forecast caused the wind project to look less favorable. Without the REC the CPW of the system annual costs is higher with the wind than without using this lower natural gas price forecast. Higher, if the REC credits are added in, even under the lower natural gas price forecast scenario, the wind project reduces CPW system costs over the ten year period compared to the no wind scenario.

Table 5. Annual Total Production Cost Simulation Results for Scenarios Analyzed.

	Total Cost, $1000									
Year	Base No Wind	Wind-1	Wind-2	Wind-3	Wind-4	No Wind High NG and Electric price forecast	No Wind Sprng 2006 price forecast	Wind-1a	Wind-2a	Wind-3a
2007	98,945	98,945	98,945	98,945	100,018	100,018	99,725	99,725	99,725	99,725
2008	107,395	107,087	107,076	107,306	108,908	109,527	106,175	106,021	106,011	106,218
2009	107,352	107,269	107,276	107,471	108,814	109,140	103,236	103,737	103,743	103,849
2010	114,177	114,520	114,497	114,645	115,862	115,739	113,120	113,646	113,631	113,757
2011	125,297	125,470	125,458	125,612	127,149	127,239	125,303	125,506	125,495	125,644
2012	138,732	138,157	138,144	138,357	142,035	142,940	138,870	138,332	138,318	138,526
2013	135,480	135,152	135,133	135,151	137,660	138,363	134,658	134,439	134,422	134,413
2014	140,758	140,733	140,728	140,691	143,854	144,159	140,299	140,364	140,359	140,305
2015	144,143	144,088	144,083	144,244	145,709	145,959	142,884	142,999	142,994	143,132
2016	147,790	147,917	147,912	148,001	149,471	149,537	149,591	149,567	149,561	149,656
2017	151,285	150,840	150,834	151,010	152,606	153,276	152,252	151,701	151,694	151,826
CPW (2006$)	$1,000,649	$999,858	$999,793	$1,000,782	$1,015,438	$1,018,106	$996,016	$996,143	$996,084	$996,890
Annual (2006$)	$100,065	$99,986	$99,979	$100,078	$101,544	$101,811	$99,602	$99,614	$99,608	$99,689
	Wind-1	Base Curtailment				Wind-1a	Base Curtailment, Spring 2006 forecast			
	Wind-2	No Curtailment				Wind-2a				
	Wind-3	High Curtailment				Wind-3a	High Curtailment, Spring 2006 forecast			
	Wind-4	High NG price/No Curtailment								

Table 6. Annual Net Benefit of Wind Production Cost Simulation Results.

		Net Benefit, $1000							
	Year	Wind-1	Wind-2	Wind-3	Wind-4	Wind-1a	Wind-2a	Wind-3a	REC credit
	2007	-	-	-	-	-	-	-	0
	2008	308	318	89	619	154	163	(43)	313
	2009	82	75	(119)	326	(501)	(507)	(613)	312
	2010	(343)	(320)	(468)	(123)	(526)	(511)	(638)	312
	2011	(172)	(160)	(315)	90	(204)	(192)	(341)	312
	2012	575	588	375	905	539	552	344	313
	2013	328	347	330	703	219	236	245	312
	2014	24	30	67	306	(65)	(60)	(5)	312
	2015	55	60	(101)	250	(115)	(110)	(248)	312
	2016	(127)	(122)	(211)	66	24	29	(66)	313
	2017	445	451	275	670	552	558	426	312
	CPW (2006$)	$790	$856	($133)	$2,668	($127)	($68)	($874)	$2,198
	Annual (2006$)	$79	$86	($13)	$267	($13)	($7)	($87)	$220
CPW with $3 REC credit		$2,989	$3,054	$2,065	$4,866	$2,072	$2,130	$1,324	
Annual with $3 REC credit		$299	$305	$207	$487	$207	$213	$132	

Appendix D

Electric Master Plan Review and Power Market Assessment Executive Summary

This report reflects an independent review and update of the Kansas City Board of Public Utilities (BPU) Electric System Master Plan - 2003 and latest demand and energy forecast prepared in 2005 and is intended to serve as the basis for a commitment by the BPU to its next major power supply resource to be available by or before 2012. It is being conducted in parallel with a Baseload Generation Siting Study designed to identify the most feasible site for new baseload generation available to the BPU system, and contains a Wholesale Power Market Assessment designed to identify other utilities needing additional generation with the common goal of the acquisition of additional generating capacity and energy to meet the needs of a growing service area. BPU's objective in potentially teaming with other utilities is two fold:

- To reduce the costs to BPU customers of excess capacity that typically exists in the years immediately following the addition of the next major new generation resource, and
- To take advantage of the potentially significant economies-of-scale associated with the construction of generators larger than would be required for BPU alone.

By conducting the Siting and Market Assessment studies concurrent with the Master Plan Update, the BPU will ensure that the costs of new generation resources considered in the Master Plan reflect site specific conditions and cost-effective generator unit sizing. The concurrent studies are also designed to preserve the lead time required to design, permit and construct a new coal fueled generator for commercial operation in 2012 as indicated in the 2003 Master Plan.

This independent Master Plan Review and Update addresses the future power supply needs of the BPU's native load customers, plus the wholesale power sales commitments under existing contracts through 2021-2022. The Master Plan Review and Update also considers the age and ability of the existing BPU generators to continue providing the level of economic and reliable service they have provided over the past 35 or more years. The period of study is the 25-year period 2006 through 2030. The Master Plan Review includes the following elements:

- Forecast Need for Power--A review of previous BPU electric load and generating capacity requirement forecasts, a forecast of the capabilities and costs of existing BPU generators and power purchases and a forecast of the timing and size of additional generating capacity needs.

- Characterization of New Power Supply Resources--Description of the new power supply resources available to the BPU including conventional and renewable supply-side generation options, demand-side management programs designed to reduce the demand for power and possibly delay the need for new generation, and purchased power opportunities.
- Supply Side and Demand Side Resource Screening--A qualitative comparison of alternative resources with regard to their applicability to the BPU system along with a lifecycle cost comparison of the applicable options.
- Financial Comparison of Alternative Power Supply Plans--The identification of alternative plans to meet 2006-2030 generating capacity and energy needs and the comparison of these plans on a comparative revenue requirement basis. Includes associated risk and contingency analyses.
- Bilateral Power Market Description--A description of the potential availability of baseload purchased power to be acquired in lieu of construction of a new BPU resource, and a description of the initial responses to a bridge power solicitation.
- Conclusions and recommendations.

Forecast Need for Power

The forecast need for additional generation capacity for the BPU system is a function of projected load growth on the BPU system, the future capacity of BPU's existing generation fleet, and firm sales of capacity and energy and purchases of capacity and energy currently under contract. Until recently, population in Wyandotte County, Kansas had been on the decline. However, development of the International Speedway and the Village West shopping and entertainment area beginning in 2002 has spawned an increase in population in BPU's service area and an even bigger increase in households. Using the latest available population forecast from the Mid America Regional Council, the forecast of Net System Energy requirements for the BPU system is projected to increase at an average rate of 0.9 percent over the next 25 years from 2,611 GWh in 2005 to 3,287 GWh in 2030. The forecast of normal weather peak demand is also projected to increase at an average rate of 0.9 percent per year from 523 MW forecast for 2006 to 646 MW by 2030. Similarly, the forecast of extreme weather peak demand is forecast to increase to 670 MW by 2030. With a 12 percent capacity margin requirement, BPU's projected capacity requirements increase from 616 MW in 2006 to 761 MW in 2030.

The future capacity of existing generators is an issue for this study primarily because the existing Quindaro Units 1 and 2 reach 55 years of age by 2022 and 2027, respectively. By that time, these generating units will have long surpassed their 30-year design lives and the intervening years are likely to entail significantly increased maintenance costs and pressure to add new air emission control technology. While the economic retirement of Quindaro Units 1 and 2 is a subject of this study, the starting assumption is that they will be retired in 2022 and 2027. BPU's existing combustion turbine units, CT1, CT2 and CT3, are also projected to retire during the planning period when they turn 45 years of age. Because 45 years is so far beyond the design lives of these units, their economic retirement is not a subject of this study and they are assumed to be retired in 2014, 2019 and 2022.

Continued experiencing difficulties obtaining firm transmission service for BPU's existing power purchase arrangement with the Southwest Power Administration (SWPA) which leads to the assumption that, while this 38 MW resource will continue to be available to BPU it will be available on a non-firm basis. The 5 MW Western Area Power Administration (WAPA) purchase, which does have firm transmission service, was assumed to be available throughout the study period. The Nearman 1 Participation Sales agreements with the Columbia, Missouri Electric Department and with the Kansas Municipal Energy Agency are not assumed to be renewed upon their expiration in 2021 and 2022.

Table ES-1 and Figure ES-1 reflect the resulting need for additional generating capacity based on the capacity requirements and capacity of existing generation supplies described above.

Future Power Supply Options

Alternative power supply options considered for meeting BPU's need for capacity and energy consist of both demand- and supply-side resources and include a number of renewable energy resources. The following supply-side resource options were considered in this study:

- Simple Cycle Combustion Turbines (SCCT):
- Aeroderivative combustion turbines (LM2500, LM6000-SPRINT, LMS100).
- E Class simple cycle combustion turbines (7EA).
- Combined Cycle Combustion Turbines (CCCT):
- 1x1 E Class combined cycle (1-on-1 7EA).
- 1x1 F Class combined cycle (1-on-1 7FA).
- Conventional Coal:
- 125 MW pulverized coal (PC).

- 175 MW PC
- 235 MW PC
- 235 MW circulating fluidized bed.
- 400 MW PC for maximum joint ownership.
- Advanced Coal:
- 300 MW Integrated gasification combined cycle (IGCC).
- In addition to the generators listed above, B&V also considered the following renewable resources:
- Solid biomass:
- Direct fired.
- Co-fired with coal.
- Biogas:
- Anaerobic digestion.
- Landfill gas (LFG).
- Biofuels:
- Ethanol.
- Biodiesel.
- Waste-to-Energy:
- Mass burn.
- Refuse derived fuel (RDF).
- Hydroelectric.
- Solar:
- Solar photovoltaic.
- Solar thermal electric.
- Wind.

Detailed descriptions of the operating characteristics, capital, and operating costs for each of these options are contained in the accompanying Technology Characterization Report prepared as part of this Master Plan Update.

Demand-side options considered in this study include various affordability, efficiency, and demand response programs designed for new and existing customers in the residential, commercial and industrial customer classes.

A comparison of the supply-side options listed above on an “all in” or busbar cost basis over a 20-year operating period and the full range of capacity factors yielded the following conclusions:

- PC technology is less costly than CFB technology for new coal fueled generation given forecast of delivered coal prices to BPU.
- Measurable economies of scale exist in the capital cost of alternatively sized generators within a technology type.
- There are no capacity factors at which combined cycle generation appears to be cost effective for utilities like BPU.
- IGCC capacity is measurably more expensive than PC capacity before accounting for the diminished availability of IGCC generators during their initial operating years.
- Landfill gas and wind generation are the two renewable resources that appear to be cost competitive with the conventional generation resources.

The forecast of delivered fuel prices and emission allowance prices used to compare the conventional supply-side resources are contained in Figures ES-2 and ES-3, respectively. For purposes of amortizing the capital costs of alternative generators, the following finance periods and capital charge rates were assumed:

- Coal, financed over 30 years--8.91 percent.
- Combined cycle, financed over 25 years--9.55 percent.
- Combustion turbine, financed over 20 years--10.67 percent.

Table ES-1
Forecast Balance of Loads and Resources - BPU System

Description	Type[g]	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
System Peak Demand		542	552	557	563	568	573	577	582	587	592	597	602	607	612	617	622	627	632	637	643	648	653	659	664	670
System Capacity Responsibility [a]		616	627	633	640	645	651	656	661	667	673	678	684	690	695	701	707	713	718	724	731	736	742	749	755	761
Accredited Generating Capacity (Net of Station Service)																										
Quindaro #1, Coal (1966-2022)	B	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72									
Quindaro #2, Coal (1971-2026)	B	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95				
Quindaro #2, Gas (1971-2021)	I	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23				
Nearman #1 (1981-2031)	B	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232
Combustion Turbine #1, Gas (1969-2014)	I	12	12	12	12	12	12	12	12	12																
Combustion Turbine #2, Oil (1974-2019)	P	56	56	56	56	56	56	56	56	56	56	56	56	56	56											
Combustion Turbine #3, Oil (1977-2022)	P	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49	49								
Combustion Turbine #4 Gas & Oil (2006-2051)	I	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Total Installed Generation		614	614	614	614	614	614	614	614	614	602	602	602	602	602	546	546	474	425	425	425	425	307	307	307	307
Purchases																										
SWPA Hydro	I	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
WAPA Hydro	I	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Total Capacity Purchases		43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
Nearman Participation Sales																										
Columbia (1987-2022) (Firm NC1)	B	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)	(20)								
KMEA (1982-2021) (Firm NC1)	B	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)	(38)									
Total Capacity Sales		(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(58)	(20)	0	0	0	0	0	0	0	0
Total System Capacity [b]		599	599	599	599	599	599	599	599	599	587	587	587	587	587	531	531	497	468	468	468	468	350	350	350	350
Capacity Balance [c]		57	47	42	36	31	26	22	17	12	(5)	(10)	(15)	(20)	(25)	(86)	(91)	(130)	(164)	(169)	(175)	(180)	(303)	(309)	(314)	(320)
Percent Capacity Balance (%) [d]		10%	8%	7%	6%	5%	4%	4%	3%	2%	-1%	-2%	-3%	-3%	-4%	-16%	-17%	-26%	-35%	-36%	-37%	-38%	-87%	-88%	-90%	-91%
Capacity Surplus / (Deficit) [e]		(17)	(28)	(34)	(41)	(46)	(52)	(57)	(62)	(68)	(86)	(91)	(97)	(103)	(108)	(170)	(176)	(216)	(250)	(256)	(263)	(268)	(392)	(399)	(405)	(411)
Capacity Surplus / (Deficit) [f] less SWPA nonFirm		(55)	(66)	(72)	(79)	(84)	(90)	(95)	(100)	(106)	(124)	(129)	(135)	(141)	(146)	(208)	(214)	(254)	(288)	(294)	(301)	(306)	(430)	(437)	(443)	(449)

Capacity Margin: 12%

Notes: [a] System Capacity Responsibility = System Peak Demand / (1-(% Capacity Margin/100))

[b] Total System Capacity = Total Installed Generation + Total Capacity Purchases - Total Capacity Sales

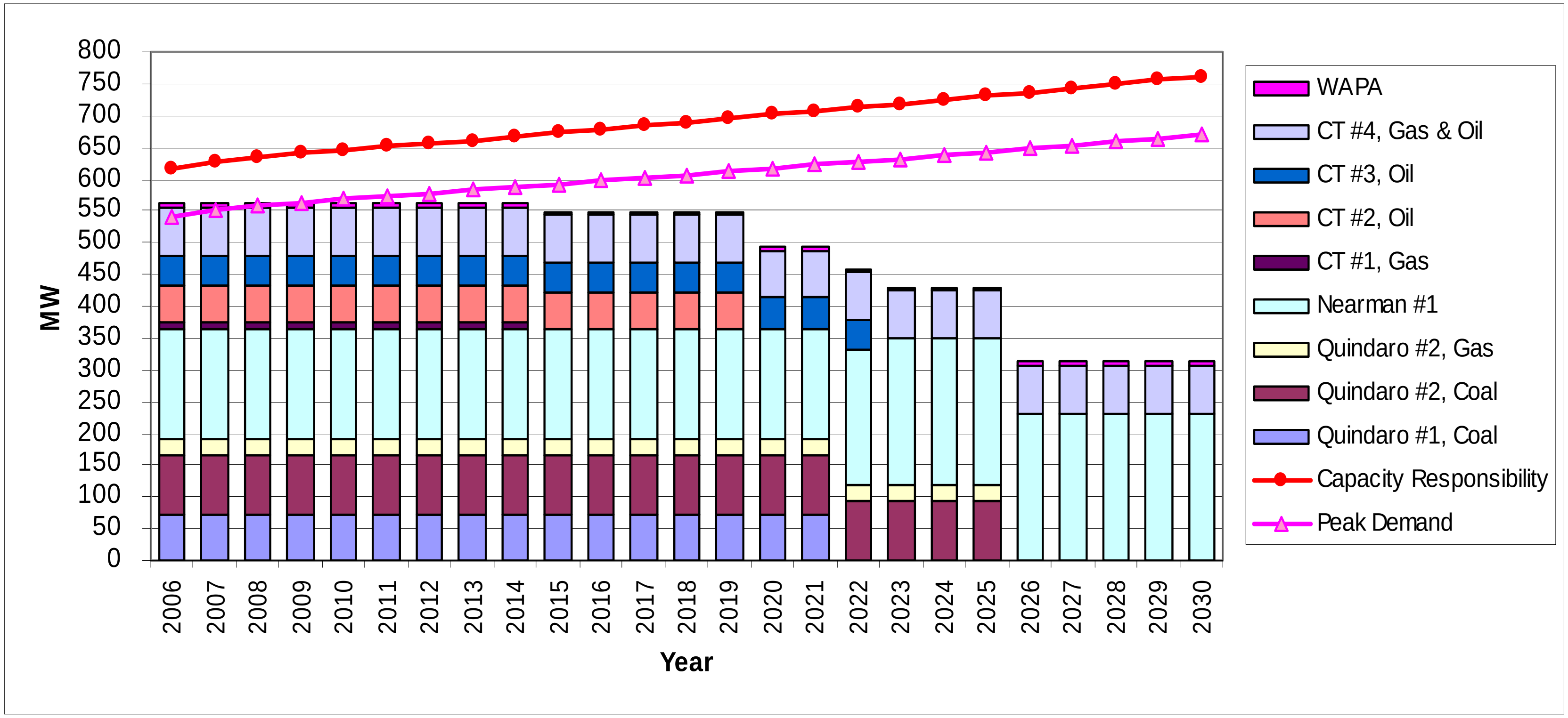
[c] Capacity Balance = Total System Capacity - System Peak Responsibility

[d] Percent Capacity Balance = (Capacity Balance / Total System Capacity) X 100

[e] Capacity Surplus/(Deficit) = Total System Capacity - System Capacity Responsibility

[f] Capacity Surplus/(Deficit) - SWPA Hydro which is nonfirm

[g] Generator Type: B = Base, I = Intermediate, P = Peaking



Resource Capacities:

WAPA - 5 MW	Nearman Unit 1 (BPU share) - 174-232 MW
CT 4 - 75 MW	Quindaro Unit 2 - 118 MW
CT 3 - 49 MW	Quindaro Unit 1 - 72 MW
CT 2 - 56 MW	
CT 1 - 12 MW	

Figure ES-1
Forecast Balance of Loads and Resources - BPU System

Alternative Capacity Expansion Plans

Based on the need for additional generating capacity and the results of a busbar cost screening of alternative supply-side resources Black & Veatch used its optimum generation expansion model, POWROPT, to identify 11 initial generation expansion plans for comparison on a 25-year forecast basis. Given the choice of adding combustion turbine, combined cycle or PC resources to supplement BPU's existing generation fleet, the POWROPT model consistently chose a new coal fueled resource as the first generation addition even though new coal generation was not assumed to be available for BPU operation until 2012. (While new combustion turbine and combined cycle resources were available for selection in 2009 and 2011, respectively, additional coal generation was added in addition to the SCCT or PC capacity as soon as it was available in 2012.)

The plans to be compared consisted of BPU utilizing various portions (155 to 235 MW) of a 235 MW PC in 2012 and selling the remaining portion of the unit on a life-of-the-unit participation sale basis or in a joint ownership arrangement. They also included the construction and sole ownership of a 125 MW and a 175 MW PC by BPU in 2012 and the addition of a 232 MW combined cycle unit with BPU taking 116 MW and selling the remainder for the life of the unit. (While combined cycle capacity appears to be non-economic for the BPU system, a combined cycle plan was included in order to test various fuel price and emission price risks.) In all cases, POWROPT was used to optimize each plan by identifying the subsequent generation additions that would minimize the 25-year revenue requirements of that plan. In addition to the plans described so far, four additional plans were developed that assumed the participation sale in the 235 MW unit was temporary and that the sale capacity was reclaimed by BPU when needed. Finally, five alternative versions of some of the previous plans were hypothesized for purposes of investigating the economics of the early and delayed retirement of Quindaro Units 1 and 2. Table ES-2 lists the initial expansion plans compared for this study.

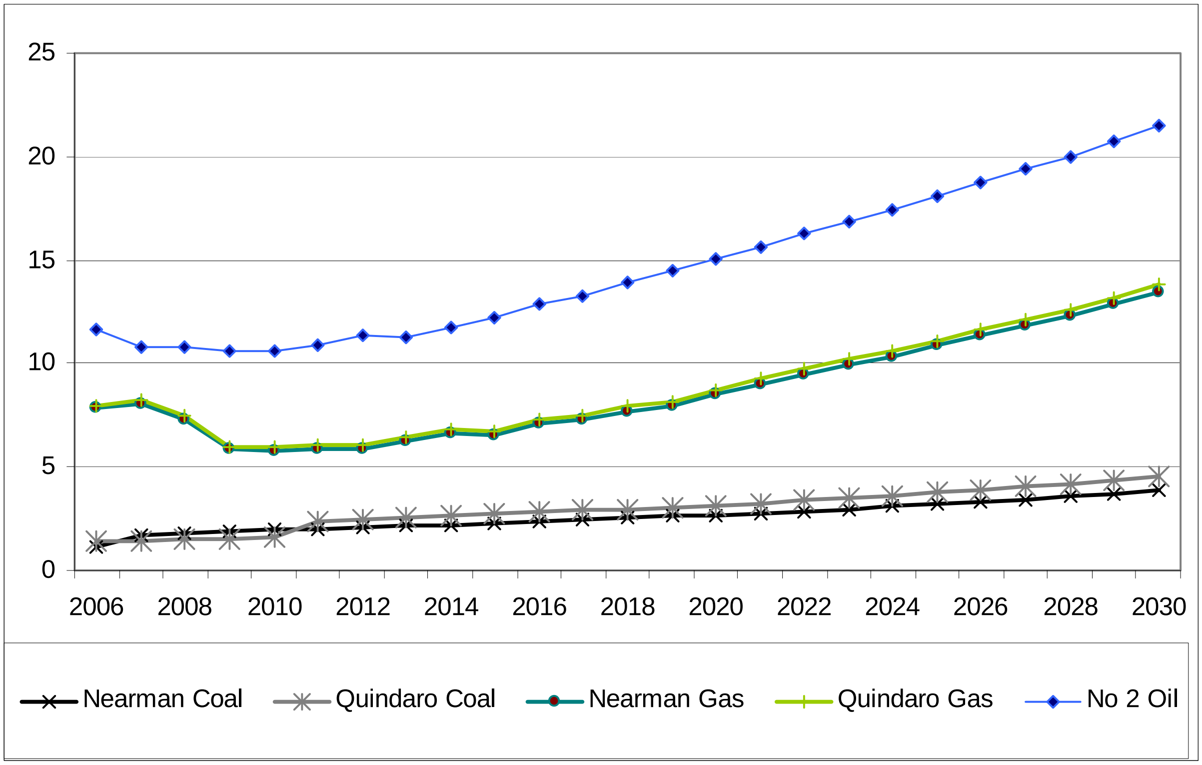


Figure ES-2
Comparative Fuel Price Forecasts Delivered to BPU Generators

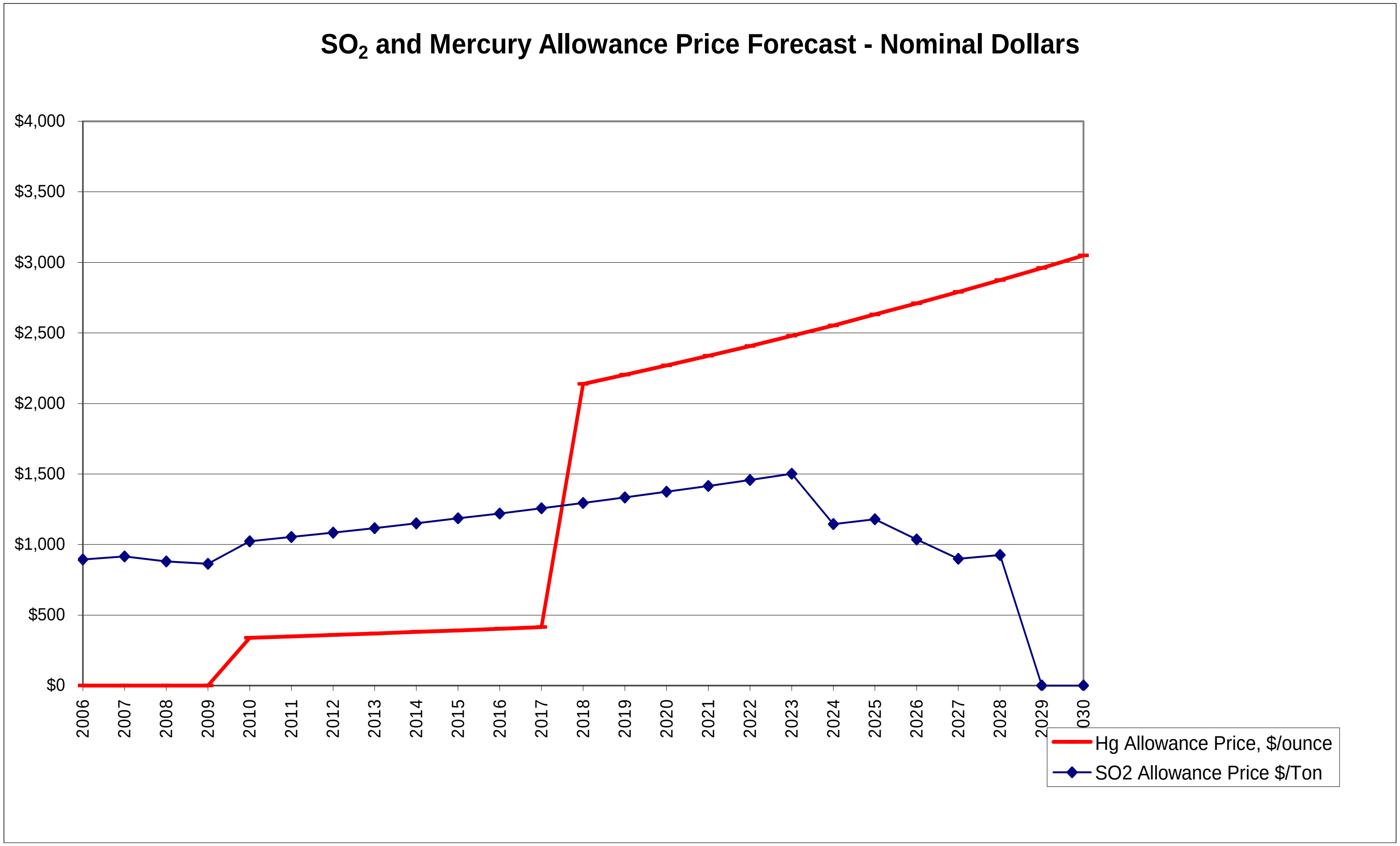


Figure ES-3
SO_2 and Mercury Allowance Price Forecast - Nominal Dollars

Financial Comparison of Alternative Plans

The initial criterion for the comparison of the alternative capacity expansion plans is the Net Present Value of Comparative Revenue Requirements for BPU's retail customers.

Comparative revenue requirements are defined to include the amortized capital costs associated with all new generation additions and new pollution control equipment, fixed O&M on all new generation additions, system-wide energy production costs and economy energy purchases. They are net of proceeds from economy energy sales and are also net of the proceeds from the sale of participation power under the remaining wholesale contracts. System-wide production costs consist of fuel and variable O&M costs including unit startup costs and emission allowance purchases for all new and existing generators. Debt service associated with existing plants is not included because these costs are expected to be the same for all plans. Similarly, transmission, distribution, and customer service costs are not included because these costs are also assumed to be the same for all expansion plans. For purposes of the initial expansion plan comparison, BPU's capacity and energy needs prior to 2012 were assumed to be met by short-term (possibly yearly) purchases priced in accordance with the forecast of spot market prices.

The comparison of the plans in which BPU would utilize between 155 and 235 MW of a new 235 MW PC operational in 2012 indicated that BPU's take of 175 MW would have the lowest comparative revenue requirements. Of the plans in which BPU would be a sole-owner of a new PC unit in 2012, the addition of a 235 MW PC had the lowest comparative revenue requirements. Of the plans in which BPU was assumed to take between 135 and 195 MW of a new 235 MW PC unit in 2012 and to sell participation capacity at cost for a limited time until 2018 or 2020, BPU's use of 135 MW initially and reclaiming the 100 MW in 2020 was the least cost plan. The plan in which BPU takes 116 MW of a new 232 MW combined cycle unit, when compared to all of the previous plans that add PC capacity in 2012, costs 4 to 6 percent more on a net present value basis and is more expensive in the first year. Figures ES-4 through ES-6 illustrate the annual comparative revenue requirements in $/MWh for the plans calling for a 235 MW PC with various participation sales levels, the plans allowing for limited participation sales and capacity return and calling for the BPU solely-owned PC additions in 2012. On a Net present value basis, the best plan, hereafter referred to as the Base Plan, takes 135 MW of the 235 MW PC in 2012 and reclaims 100 MW of participation power in 2020. If such an arrangement cannot be negotiated with a power buyer, the next least-cost plans are those with a life-of-the-unit participation sale or joint ownership with BPU taking 175 MW up to 235 MW of a 235 MW PC in 2012. BPU's sole ownership of a 235 MW PC is lower in cost than sole-ownership of a 175 MW PC and much lower in cost than the combined cycle plan.

Table ES-2
Generating Capacity Expansion Plans[1,2]

Plan	Unit Additions	Year	Plan	Unit Additions	Year
135 MW of 235 MW PC	PC UNIT (135 MW of 235 MW)	2012	**235 MW PC**	PC UNIT (235 MW)	2012
	PC UNIT (175 MW)	2018		LM6000 CT	2022
	LM6000 CT	2027		LM6000 CT	2023
	LM6000 CT	2027		LM6000 CT	2027
	7EA CT	2027		7EA CT	2027
				LM2500 CT	2028
155 MW of 235 MW PC	PC UNIT (155 MW of 235 MW)	2012	**235 MW of 290 MW IGCC**	IGCC UNIT (235 MW of 290 MW)	2012
	PC UNIT (125 MW)	2020		LM6000 CT	2022
	LM6000 CT	2023		LM6000 CT	2023
	7EA CT	2027		LM6000 CT	2027
	LM6000 CT	2027		7EA CT	2027
	LM2500 CT	2029		LM2500 CT	2028
175 MW of 235 MW PC	PC UNIT (175 MW of 235 MW)	2012	**175 MW PC**	PC UNIT (175 MW)	2012
	LM6000 CT	2020		LM6000 CT	2020
	LM6000 CT	2022		LM6000 CT	2022
	LM6000 CT	2023		LM6000 CT	2023
	LM2500 CT	2026		LM2500 CT	2026
	LM6000 CT	2027		LM6000 CT	2027
	7EA CT	2027		7EA CT	2027
	LM2500 CT	2030		LM2500 CT	2030
195 MW of 235 MW PC	PC UNIT (195 MW of 235 MW)	2012	**125 MW PC**	PC UNIT (125 MW)	2012
	LM6000 CT	2020		PC UNIT (175 MW)	2016
	LM6000 CT	2022		LM6000 CT	2025
	LM6000 CT	2023		LM6000 CT	2027
	LM6000 CT	2027		7EA CT	2027
	7EA CT	2027			
	LM2500 CT	2029			
			235 MW PC, 100 MW firm sales with capacity return in 2018	PC UNIT (235 MW 100 sold)	2012
215 MW of 235 MW PC	PC UNIT (215MW of 235 MW)	2012		PC UNIT (235 MW) Capacity return	2018
	LM6000 CT	2022		LM6000 CT	2022
	LM6000 CT	2023		LM6000 CT	2023
	LM6000 CT	2025		LM6000 CT	2027
	LM6000 CT	2027		7EA CT	2027
	7EA CT	2027		LM2500 CT	2028
116 MW of 232 MW CC	1x1 7FA CC (116 MW OF 232 MW)	2012	**235 MW PC, 100 MW firm sales with capacity return in 2020**	PC UNIT (235 MW 100 sold)	2012
	PC UNIT (235 MW)	2015		PC UNIT (235 MW) Capacity return	2020
	7EA CT	2027		LM6000 CT	2018
	LM2500 CT	2027		LM6000 CT	2023
				LM6000 CT	2027
				7EA CT	2027
				LM6000 CT	2028
			235 MW PC, 60 MW firm sales with capacity return in 2020	PC UNIT (235 MW 60 sold)	2012
All CC/CT	1x1 7FA CC (116 MW OF 232 MW)	2012		PC UNIT (235 MW) Capacity return	2020
	1x1 7FA CC (232 MW)	2015		LM6000 CT	2022
	7EA CT	2027		LM6000 CT	2023
	LM2500 CT	2027		LM6000 CT	2027
				7EA CT	2027
				LM6000 CT	2028
			235 MW PC, 40 MW firm sales with capacity return in 2020	PC UNIT (235 MW 40 sold)	2012
				PC UNIT (235 MW) Capacity return	2020
				LM6000 CT	2022
				LM6000 CT	2023
				LM6000 CT	2027
				7EA CT	2027
				LM2500 CT	2028

(1) Unless otherwise noted, assumed retirements of existing units are as follows: CT No. 1 Year 2015; CT No. 2 Year 2020; CT No. 3 Year 2023; Quindaro Unit 1 Year 2022; and Quindaro Unit 2 Year 2027.

(2) All plans using 235 MW PC were also forecast assuming a 400 MW PC. Since participation sales are assumed to be at cost, economy-of-scale savings for the BPU share accrues to BPU.

Table ES-2 (Continued)
Generating Capacity Expansion Plans[1,2]

Plan	Unit Additions	Year	Plan	Unit Additions	Year
235 MW PC, No Retire Q1 and Q2 235 MW PC, No Retire Q1 and Q2	PC UNIT (235 MW) LM6000 CT PC UNIT (235 MW) LM6000 CT	2012 2027 2012 2027	**135 MW of 235 MW PC, 100 MW firm sales with capacity return in 2020, Retire Q1 and Q2 in**	PC UNIT (235 MW 100 sold) PC UNIT (235 MW) Capacity return PC UNIT (175 MW PC) LM6000 CT	2012 2020 2016 2024
235 MW PC, Retire Q1 in 2014 and Q2 in 2015	PC UNIT (235 MW) LM6000 CT LM6000 CT LM6000 CT 7EA CT LM2500 CT	2012 2016 2020 2026 2016 2020	**135 MW of 235 MW PC, 100 MW firm sales with capacity return in 2020, No Q1 and Q2 Retirements**	PC UNIT (235 MW 100 sold) PC UNIT (235 MW) Capacity return LM6000 CT	2012 2020 2027
235 MW PC, No Retire Q1 and Q2	PC UNIT (235 MW) LM6000 CT	2012 2027			

(1) Unless otherwise noted, assumed retirements of existing units are as follows: CT No. 1 Year 2015; CT No. 2 Year 2020; CT No. 3 Year 2023; Quindaro Unit 1 Year 2022; and Quindaro Unit 2 Year 2027.
(2) All plans using 235 MW PC were also forecast assuming a 400 MW PC. Since participation sales are assumed to be at cost, economy-of-scale savings for the BPU share accrues to BPU.

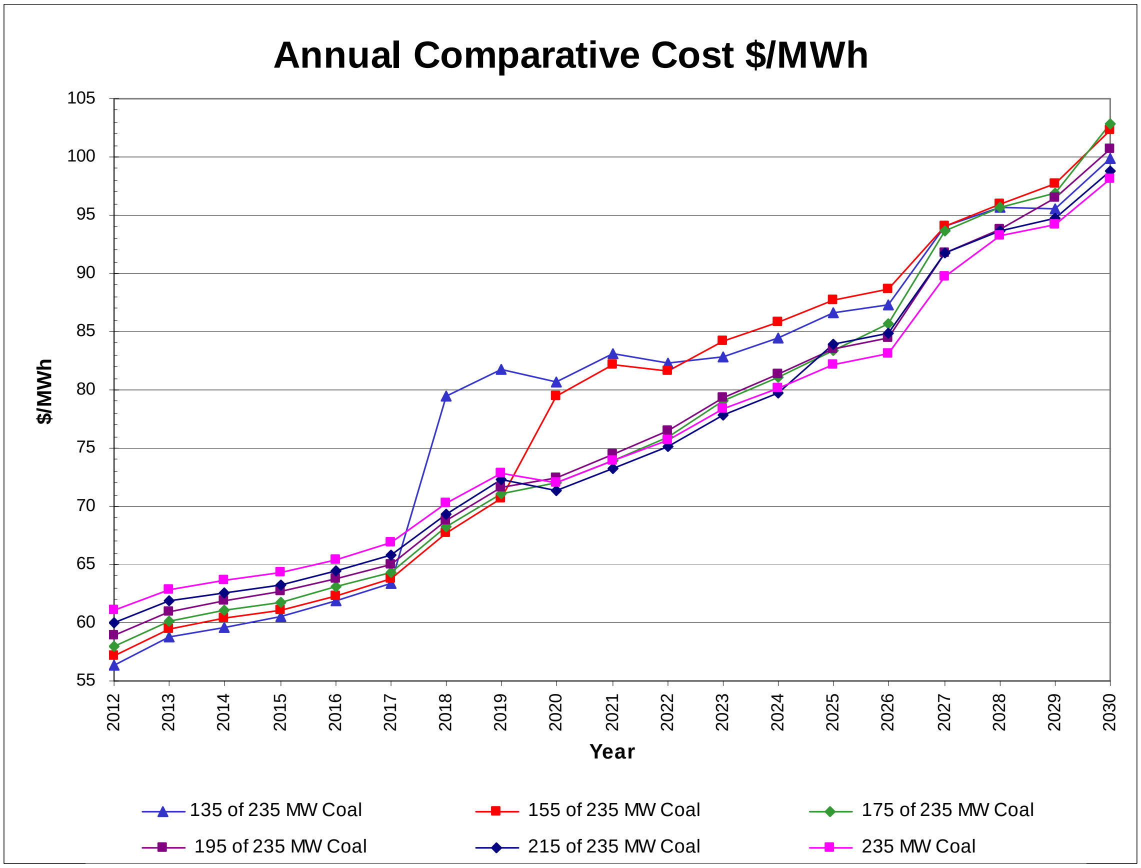


Figure ES-4
$/MWh Comparative Revenue Requirements - 235 MW PC
with Various Participation Sales Levels

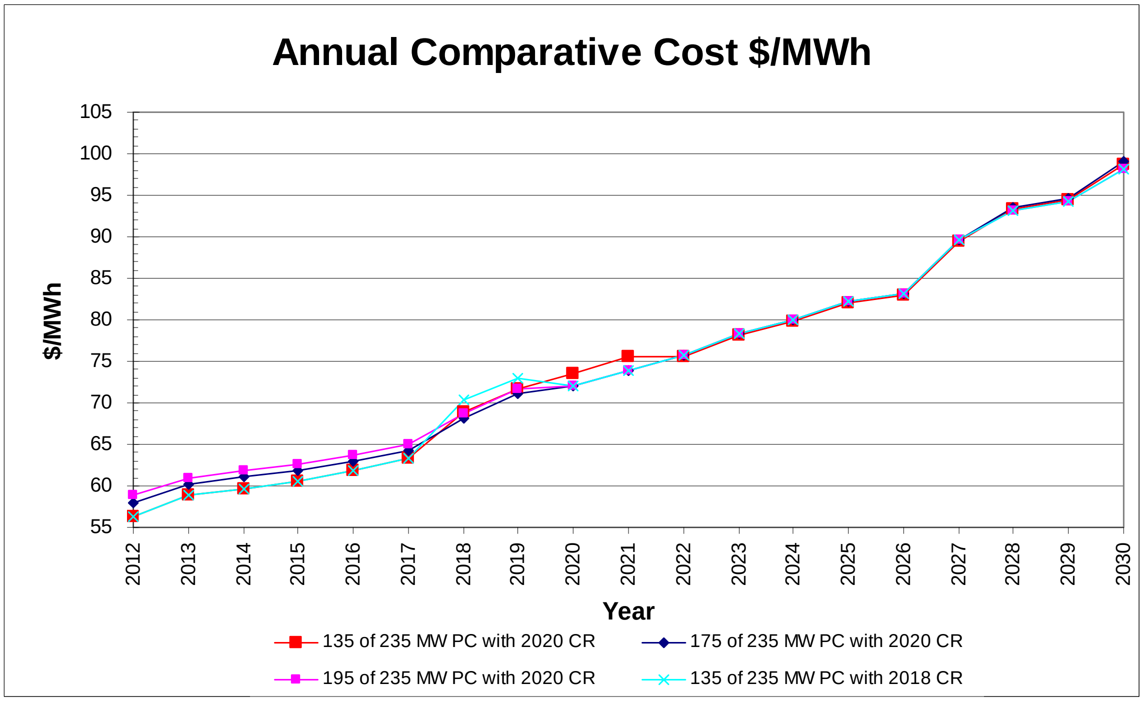


Figure ES-5
$/MWh Comparative Revenue Requirements - PC Participation with Capacity Return

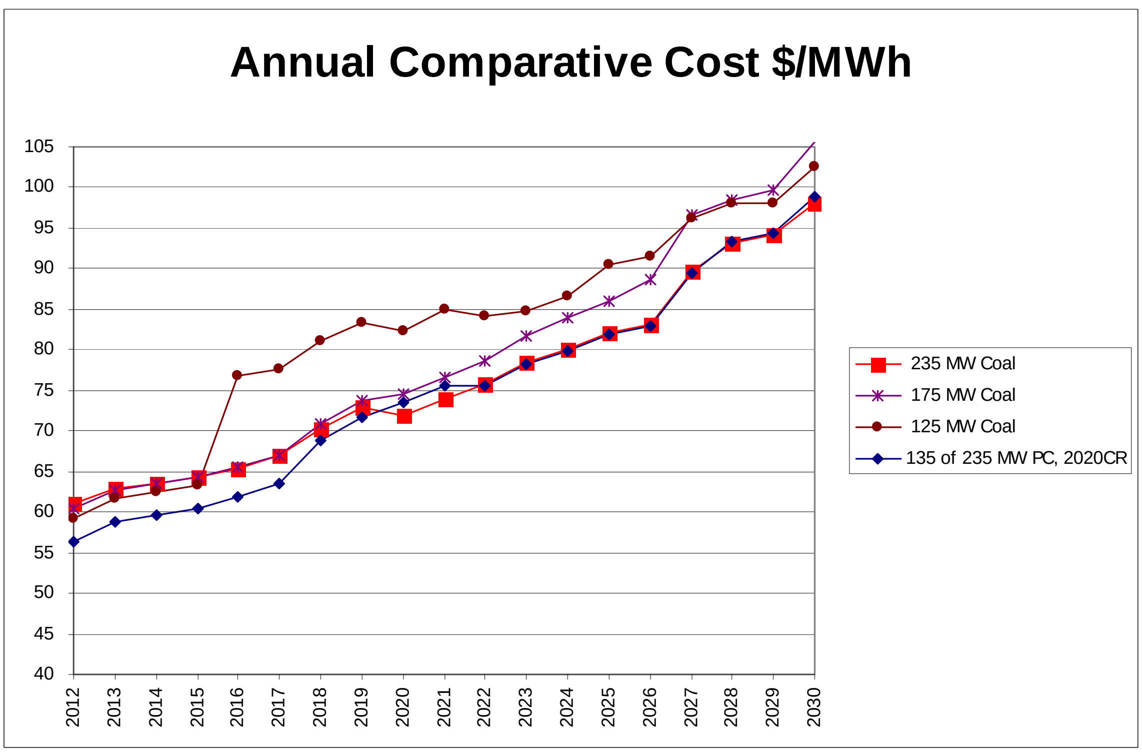


Figure ES-6
$/MWh Comparative Revenue Requirements - Base and Solely Owned PC Plans

Tests of the economics of the early and delayed (beyond 2030) Quindaro Units 1 and 2 retirement involved the simultaneous comparison of plans that added more coal capacity in early years and plans, like the Base Plan, that added only capacity as needed. All of these plans were compared assuming the forecast increase in Quindaro maintenance costs of $6.65 million ($2006) and assuming future air quality control regulations either do or do not force BPU to spend $110 million on these units. The finding of this analysis was that without the requirement for additional AQC expenditures, BPU should plan to run Quindaro Units 1 and 2 as long as possible. With the requirement of as much as $110 million in AQC expenditures, on top of the increased maintenance expense, it would likely be more economical to replace the capacity in the units. If BPU has added a new 235 MW PC (and can claim all the capacity for its own use) the Quindaro Units 1 and 2 capacity can be replaced with simple cycle combustion turbines.

The previously described results led to the selection of the following five key plans for further analysis and stress testing:

- Base Plan--135 MW of a 235 MW PC with Capacity Return in 2020.
- 235 MW PC.
- 175 of a 235 MW PC.
- 175 MW of a 235 MW PC with Capacity Return in 2020.
- 116 of a 232 MW Combined Cycle.

The combined cycle plan, though significantly more costly, was included in the key plans as a basis for comparison to check the risks of a 2012 coal fueled addition. Because a coal fueled addition in 2012 was so strongly favored by the base case comparisons, sensitivity cases were chosen primarily to measure the risks associated with coal generation. Each of the key plans listed above were compared under the following sensitivity cases:

- Loss or gain of a very large customer.
- Lower long-term gas prices and higher long-term coal prices.
- Lower SO2 emission allowance prices and a new NOx cap.
- 30 percent higher capital costs for the 2012 capital addition.
- Higher and lower spot market prices.
- A $15/ton ($2006) carbon tax.
- Low loads combined with high coal prices.
- High capital costs combined with a carbon tax.

Table ES-3 lists the ranking of the five key plans under the base case assumptions of future conditions and under each of the sensitivity cases. Under all sensitivity cases, the 135 of a 235 MW PC plan with 100 MW capacity return in 2020 had the lowest comparative revenue requirements. The next best plan calls for BPU to take 175 of a 235 MW PC with a 60 MW capacity return in 2020 followed by a 235 MW PC plan with a life-of-unit sale of 60 MW (BPU takes 175 MW). The fourth ranked plan calls for BPU's construction of a solely-owned 235 MW PC in 2012. In all but the case of high capital costs and a carbon tax, the combined cycle plan was most costly.

The following additional issues were addressed in the financial analysis in the context of the previously described Base Plan:

- The economics of landfill gas and wind generation.
- The potential impact of a direct load control program.
- The use of Eastern coal in place of Powder River Basin coal.
- The availability and price of Bridge Power.
- The financial impact of IGCC technology.
- The financial benefit of a larger sized (400 MW) PC addition.

While the financial impacts of between 10 and 30 MW of wind generation and 2.7 MW of landfill gas generation look promising, the inclusion of these renewable technologies would not alter BPU's ultimate need for over 200 MW of PC generating capacity. Direct load control appears to be worth further investigation at an installed cost of below $750/MWh, but it too will not alter BPU's need for baseload capacity. The use of Eastern coal was not found to alter the ranking of key plans and Bridge power was found to need to be approximately 60 percent more expensive than projected spot power prices before it would be cost-effective for BPU to add peaking capacity ahead of the 2012 PC capacity. Finally, the use of IGCC technology in place of a 235 MW PC was found to increase the cost of the Base Plan by 2.4 percent. Substitution of a 400 MW PC in place of the 235 MW unit was found to reduce Base Plan costs by 1.9 percent.

Bilateral Power Market in SPP

With natural gas on the margin in SPP significantly more than 50 percent of the time, many utilities in the region and surrounding areas are being induced to seek coal fueled generation to reduce their reliance on natural gas. Eighteen new coal generators under construction and under various stages of development were identified and checked for their potential to sell an ownership share or participation power to BPU. Only four of the eighteen plants identified were found to have uncommitted capacity and major transmission constraints were identified between BPU and each of these plants indicating the need for costly transmission upgrades in addition to the new generating plant costs. Because the overall market is in need of new coal generation capacity, sales of capacity from either existing or new plants can be expected to be at market prices or the cost of alternative sources of generation such as a BPU developed unit. In addition, if these plants are not developed by a public entity, any economy-of-scale savings associated with their lager size can be expected to be offset by the much higher cost of money accruing to an investor-owned utility or independent power producer.

A survey of participation sales opportunities for the sale of capacity by BPU as indicated in the Base Plan identified a number of likely buyers. At this point, no attempt has been made to qualify these candidates with regard to the availability of firm transmission service.

Table ES-3
Sensitivity/Risk Ranking of Key Plans

	Key Expansion Plans				
Sensitivity/Risk Scenario	**135 of 235 MW PC, CR2020**	**175 of 235 MW PC**	**175 of 235 MW PC, CR2020**	**235 MW PC**	**116 of 232 MW CC**
Base	1	3	2	4	5
High Load	1	3	2	4	5
Low Load	1	2	3	4	5
High Coal Price	1	3	2	4	5
Low Gas Price	1	2	3	4	5
Low SO2	1	3	2	4	5
GED NOx Price	1	3	2	4	5
Carbon Tax	1	2	3	4	5
High Capital Costs	1	3	2	4	5
High Spot Market Prices	1	3	2	4	5
Low Market Prices	1	3	2	4	5
Carbon Tax and Spot Market Adjustment	1	4	2	3	5
Eastern Coal	1	3	2	4	5
Low Load and High Coal Price	1	4	2	3	5
High Capital Costs and Carbon Tax with Market Adjustment	1	2	3	5	4
Sum of Rank	12	34	27	47	60

Observations and Conclusions

The following observations and conclusions are derived from the analyses in the previous sections of this report:

- BPU is projected to need between 55 and 449 MW of additional generating capacity to meet its capacity responsibility over the next 25 years.
- The addition of coal fueled generation as the next major generator on the BPU system is most economic followed by aero-derivative combustion turbines and more coal as and if the existing Quindaro units are retired.
- Combined cycle combustion turbines have a minor to no economic fit for systems like BPU under current projections of natural gas and coal prices.
- 135 to 235 MW of new coal fuelled capacity added in 2012 yields similar NPV revenue requirements over the next 25 years, though 235 MW yields measurably higher revenue requirements in the near-term.
- Other planned or under construction large regional coal fueled generators with capacity available to sell are physically distant from BPU. New generators closer to BPU are fully subscribed at this point.
- Major bottlenecks in the regional transmission grid preclude considering the available generators as an alternative to a BPU developed coal fueled generator.
- It is more economic to retire BPU's existing Quindaro Units 1 and 2 than to add scrubbers and SCRs to meet future environmental controls.
- It is likely not cost-effective to retire Quindaro Units 1 and 2 in the absence of new environmental controls even if repair and maintenance expenditures rise to the equivalent of another $35/kW-year.
- Assuming the retirement of Quindaro Units 1 and 2, 235 to 260 MW of new coal fuelled capacity should be added to the system over the next 25 years.
- The most economic expansion plan would add a 235 MW pulverized coal unit in 2012, sell 100 MW off-system through 2019 to utilities needing power where transmission is available and reclaim the additional 100 MW in 2020. If BPU sells that 100 MW in 4 to 5 year blocks, it may be reclaimed to replace Quindaro Units 1 and 2 should they be forced to retire with a lead time of no more than 5 years.
- This plan is a robust and least-cost plan under the following single risk scenarios:
- The gain or loss of a large customer.
- High coal prices and low gas prices.

- Lower SO2 allowance prices and a new NOx cap.
- 30 percent higher capital costs for the 2012 generator addition.
- High and low spot market prices.
- The use of Eastern coal in place of PRB coal.
- A Carbon Tax.
- In addition, the plan that has BPU take 135 of a 235 MW PC and sell 100 MW off-system through 2019, reclaiming the 100 MW in 2020, is least cost under the following double risk scenarios:
- Low load growth (loss of a large customer) and high coal prices.
- High capital costs and a carbon tax.
- Landfill gas generation appears to offer a small but cost-effective renewable generation opportunity but will not impact the decision to add BPU's next generating unit.
- Between 10 and 30 MW of wind generation may be a cost-effective generation source especially in a third-party owned structure with the owner accessing the current production tax credit and depending on the costs for required transmission upgrades but will not impact the decision to add BPU's next generating unit.
- A number of energy efficiency programs may be cost effective for the BPU system. However, they should be carefully researched before implementation and they will not impact the decision to add BPU's next generating unit. Direct load control of air conditioners may be cost effective if it can be accomplished for less than $750 MWh. For both the energy efficiency and DLC programs, BPU must consider its ability to recover its loss of revenue for transmission and distribution service.
- In the solicitation of Bridge power to meet capacity needs through 2011, BPU should consider advancing one of the aero-derivative combustion turbines as early as possible if the purchase price exceeds the current forecast for spot power purchases by approximately 60 percent.

Appendix E

Ten Year Power Supply Study
2008

Kansas City Board of Public Utilities

Ten Year Power Supply Study
Site Selection Study

Black & Veatch Project: 160817
Black & Veatch File No. 41.0040

October 2008
Revision E

Kansas City Board of Public Utilities

BLACK & VEATCH Building a world of difference.

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Acronyms

APPS	Application for Package Power Solutions
AQCS	Air Quality Control Systems
BACT	Best Available Control Technology
BPU	Board of Public Utilities
CCCT	Combined Cycle Combustion Turbine
CCG	Combined Cycle Generators
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CPW	Cumulative Present Worth
CTG	Combustion Turbine Generator
EPC	Engineering, Procurement, And Construction
ERC	Energy Rate Component
ESC	Environmental Surcharge
FOM	Fixed Operation And Maintenance
GTPE	Gas Turbine Performance Estimator
HRSGs	Heat Recovery Vapor Generators
IDC	Interest During Construction
ISO	Independent System Operator
LNB	Low NO_x Burners
N1	Nearman Unit 1
NO_2	Nitrogen Dioxide
NO_X	Nitrogen
NPDES	National Pollutant Discharge Elimination System
O&M	Operation And Maintenance
OEM	Original Equipment Manufacturer
OFA	Overfire Air
PM_{10}	Particulate Matter Of 10 Microns Or Less
PPA	Power Purchase Agreement
PSD	Prevention of Significant Deterioration
PWDR	Present Worth Discount Rate
Q1	Quindaro Unit 1
Q2	Quindaro Unit 2
SCCT	Simple Cycle Combustion Turbine
SCR	Selective Catalytic Reduction

SO_2	Sulfur Dioxide
SPP	Southwest Power Pool
SWPA	Southwest Power Administration
VOC	Volatile Organic Compounds
VOM	Variable Operation And Maintenance
WAPA	Western Area Power Administration

Executive Summary

In 2008, the Kansas City Board of Public Utilities (BPU) hired Black & Veatch to support preparation of a Ten Year Power Supply Plan. The plan was developed by conducting a 10-year power supply study along with studies to support implementation of the recommendations resulting from the power supply study. The additional studies were a siting study to determine the best location for new generating units being considered in the power supply study, and a rate impact study to quantify the rate implications of implementing the power supply study recommendations. In addition, Black & Veatch was asked to prepare a list of required permits and construction schedules.

The power supply study was conducted in two phases. Discussion of the initial power supply study process and results is contained in Phase I. The updated power supply study is contained in Phase II. The permit list and schedules related to the next unit addition in the recommend plan are in Appendix F and Appendix G, respectively.

Phase I of Power Supply Study

The 10-year power supply study was based on the demand and energy forecast developed in 2008 by BPU and considered natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The need for capacity was identified as the difference between forecast peak demand plus reserve requirements and the capacities of existing power supply resources. The study recognized the expected outputs of existing BPU generators and that the economics of the Quindaro Units' continued operation is a function of potential future environmental regulations, including the Regional Haze Rule and the ozone non-attainment conditions in the Kansas City metropolitan area. The study period was the 10-year period beginning 2008 through 2017. As shown in Tables 3-1 and 3-2 of this report, Black & Veatch identified the need for between 35 and 107 MW of additional generating capacity by 2017 depending on whether or not BPU continues to operate Quindaro Unit 1 (Q1). Phase I of the study consisted of the comparison of ten alternative generation expansion plans as shown in Table 5-1. Each plan was based on the use of simple cycle combustion turbines and/or combined cycle units burning natural gas as the primary fuel.

The study objective was to find the power supply plan that minimized overall costs to BPU customers during the ten-year study period under a range of plausible future conditions. The initial set of plan comparisons assumed forecasts of expected fuel prices (Figure 6-1), power purchase and sales prices (Table 6-2), load growth (Table 3-1), sulfur dioxide (SO_2) allowance prices and carbon dioxide (CO_2) allowance prices (Figure 6-2).

In addition, sensitivity analyses were conducted to compare the costs to customers under the following conditions:

- Gain of a large (28 MW) customer, at a load factor similar to the BPU system load factor.
- Loss of a large (28 MW) customer, at a load factor similar to the system load factor.
- High natural gas and electric market prices.
- A high cost for CO_2 emissions either as a result of a cap & trade program or the application of a carbon tax.
- No purchases of economy energy from the market reflecting an extreme case of transmission congestion.

One finding of Phase I of the study was that it is consistently less costly to continue to operate Q1 through 2017 rather than to retire it and replace it with a similar amount of combustion turbine based capacity. Q1 was assumed to be retrofit with a selective catalytic reduction (SCR) system for nitrogen oxide (NO_x) control in order to continue operating through the study period. The expansion plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle plant are not sufficient to offset a combined cycle's incremental capital cost. In the least cost plan, BPU meets additional load growth with the addition of a 43 MW LM6000 type aero-derivative combustion turbine in 2011. The second least-cost plan also assumed Q1 remains in service and that two smaller (21 MW) LM2500 type combustion turbines are added for growth, one in 2011 and one in 2015. In the third least cost plan, a 75 MW Frame 7EA combustion turbine is added in 2011.

These analyses also indicated that under all sensitivity case assumptions of future conditions, the least-cost 10-year expansion plan is the plan that retains Quindaro Unit 1 and adds an LM6000 or similar simple cycle combustion turbine in 2011. However, the costs of plans that substitute two smaller simple cycle combustion turbines or a larger frame type combustion turbine like the GE 7EA are close enough in NPV cost to warrant BPU's solicitation of both aeroderivative and frame type combustion turbine machines as well as machines of similar size and performance from other manufactures. The continued operation of Q1 with an SCR was estimated to be economical under a variety of sensitivity/risk scenarios.

Phase II of Power Supply Study

The results of the Phase I analysis were used as a starting point for Phase II in which the modeling input assumptions were refined and fuel and market price forecasts were updated. The Phase II analysis considered the top five plans, on a cumulative net present value basis, from the Phase I analysis. The plans considered in Phase II are listed in Table 16-2. Results of the Phase II analysis were consistent with those of Phase I. Because the NPV costs of the three least-cost plans calling for the addition of an LM6000 turbine, two LM2500 turbines or a 7EA turbine were so close, BPU selected the 7EA plan as the basis of the rate impact analysis in order to accommodate what is likely to be the most capital intensive of the least-cost plans and to allow BPU to maintain needed flexibility in procuring a turbine(s).

Rate Impact Forecast

The rate impact study took the forecast of electric sales, operation and maintenance costs, and fuel and purchased power costs from the Phase II results for the selected plan and added debt service on existing capital facilities and forecast debt service on new generation plant additions as well as transmission, distribution, and administrative costs to produce a forecast of total revenue requirements. Included in the financial forecast were the latest forecasts of capital requirements for the existing generators as well as the expected capital and operating costs to meet potential environmental regulations for BPU's existing generators.

The power supply plan that adds a Frame 7EA combustion turbine in 2011 is close in NPV cost to the best plan when Q1 is not retired in 2011 and is the least cost plan on a NPV basis when Q1 is retired in 2011. Therefore, regardless of whether or not Q1 is retired early, a common low cost plan is to install a Frame 7EA in 2011. Accordingly, the financial forecast was developed using the projected costs of that plan and the assumption that Q1 will not be retired until after 2017. The results of the financial forecast indicated a total revenue deficiency under existing base rates of approximately $115 million for the period 2009 through 2013. To offset the annual revenue deficiencies, a series of consecutive annual base rate increases and an environmental surcharge (ESC) to recover the capital portion of potential environmental upgrades are recommended.

A series of three annual six and one quarter percent base rate increases beginning in 2010 is recommended. These recommended increases were determined with the assumption that proposed changes in the Energy Rate Component (ERC) calculation to recover additional energy supply costs is implemented beginning January 1, 2009. In addition, a new environmental surcharge (ESC) designed to recover all debt service payments for environmental capital improvements is also implemented beginning January 1, 2009. The ESC would be adjusted annually to recover the upcoming year's debt service payment on the environmental bonds resulting from the potential emissions control retrofits on the Quindaro and Nearman coal fueled units. The projected ESC is 0.15 ¢/kWh in 2009, 0.40 ¢/kWh in 2010, 0.56 ¢/kWh in 2011, 0.83 ¢/kWh in 2012, and 0.67 ¢/kWh in 2013.

Siting Study

A site selection study was conducted concurrently with Phase I of the power supply study. It considered both combustion turbine based simple cycle and combined cycle units using natural gas as the primary fuel and located at either existing generating stations or substations. Site comparison criteria were developed based on infrastructure and utility requirements for each technology and candidate sites were rated on their ability to meet that criteria. Initially, twenty-nine sites were considered which were screened to ten sites based on the following criteria:

- Sites which do not have current or planned access to 161 kV transmission were eliminated.
- Sites which were farther than one mile from an existing natural gas pipeline were eliminated.

Five additional sites were eliminated because space or neighborhood proximity limitations clearly could not support a new generation facility. The Nearman plant site was ultimately selected as the most suitable site for a new combustion turbine based generator addition based on socioeconomic, land use, air quality, site development, location of personnel and security scoring criteria. The evaluation scores of candidate sites used to select the Nearman site are shown in Tables 16-3 and 16-4.

Permit List

Black & Veatch developed a list of construction and operating permits likely to be required for the construction of the simple cycle combustion turbine addition recommended in the selected plan and included the permit list in Appendix F of this report. The list contains federal, state, and local permits.

Project Schedule

A schedule for the engineering, permitting, construction start-up and testing of the recommended combustion turbine addition was developed and is included in Appendix G to this report. The total project duration is thirty-three months. The air permitting process is estimated to require approximately 18 months beginning with meteorological monitoring activities and ending with receipt of the air permit. Site preparation would be scheduled to begin about twenty-one months into the schedule with construction activity being completed nine months later allowing three months for start-up, testing, and tuning before final acceptance.

1.0 Report Introduction

In 2008, the Kansas City Board of Public Utilities (BPU) hired Black & Veatch to support preparation of a Ten Year Power Supply Plan. The plan was developed by conducting a 10-year power supply study along with studies to support implementation of the recommendations resulting from the power supply study. The additional studies were a siting study to determine the best location for new generating units being considered in the power supply study, and a rate impact study to quantify the rate implications of implementing the power supply study recommendations. In addition, Black & Veatch was asked to prepare a list of required permits and construction schedules.

The power supply study was conducted in two phases. Discussion of the initial power supply study process and results is contained in Phase I. The updated power supply study is contained in Phase II. The permit list and schedules related to the next unit addition in the recommend plan are in Appendix F and Appendix G, respectively. The purpose of the study was to determine the most economical installation of units to provide the future power requirements of BPU customers.

The 10-year power supply study was based on the demand and energy forecast prepared in 2008 and considered alternative natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The power supply study was conducted in two phases with Phase I consisting of the comparison of 10 alternative generation expansion plans using simple cycle combustion turbines and/or combined cycle units to meet growth. The study period is the 10-year period beginning 2008 through 2017.

Phase II of the power supply study used results from Phase I with updated and refined modeling input assumptions. Fuel and purchase power price forecasts were updated for Phase II. Phase II analysis also included estimates for capital expenditures to maintain the safe, efficient, and reliable operation of BPU's existing units. Based on the results of Phase II of the power supply study, a BPU financial forecast for the years 2008 through 2013 was developed using the selected power supply plan. The financial forecast compared forecasts of electric utility revenue under existing rates to revenue requirements of the BPU for the period 2008 through 2013. The forecasts reflect the BPU's proposed capital program including potential environmental upgrades to the Nearman and Quindaro generating units and the addition of a new combustion turbine at Nearman (CT5). Recommend overall rate increases to offset the annual deficiencies under the current rates are detailed in the Financial Forecast of this report.

A site selection study was conducted concurrently with Phase I of the power supply study, it considered both combustion turbine based simple cycle and combined cycle units using natural gas as the primary fuel and located at either existing generating stations or substations. Site comparison criteria were developed based on infrastructure and utility requirements for each technology and candidate sites were rated on their ability to meet that criteria. Initially, twenty-nine sites were considered which were screened to ten sites based on the following criteria:

- Sites which do not have current or planned access to 161 kV transmission were eliminated.
- Sites which were farther than one mile from an existing natural gas pipeline were eliminated.

Five additional sites were eliminated because space or neighborhood proximity limitations clearly could not support a new generation facility. The Nearman plant site was ultimately selected as the most suitable site for a new combustion turbine based generator addition based on socioeconomic, land use, air quality, site development, location of personnel and security scoring criteria. The evaluation scores of candidate sites used to select the Nearman site are shown in Tables 16-3 and 16-4.

Documentation of the Phase I study work begins with an introduction to the Power Supply Study. Following the introduction to the power supply study analysis, the forecast need for power is detailed in Section 3.0, followed by descriptions of future power supply options considered in Section 4.0. Sections describing the alternative capacity expansion plans and a comparison of the NPV costs of the alternative plans are in Sections 5.0 and 6.0. Observations and conclusions resulting from the Phase I analysis are provided in Section 7.0.

The refined and updated Phase II of the Power Supply Study is described beginning in Section 8.0 followed by descriptions of Phase II expansion plans carried forward from Phase I in Section 9.0 and updates to the performance, emissions, and EPC capital cost estimates of the power supply options in Section 10.0. The comparison of the NPV costs of the alternative Phase II plans is contained in Section 11.0.

The rate impact analysis used the results from Phase II of the Power Supply Study and added additional costs to produce a forecast of total revenue requirements. Discussion of the rate impact study is in Section 13.0 of this report. This report concludes with details of the site selection study beginning in Section 14.0.

2.0 Phase I of Power Supply Study

This report describes the development of a 10-year power supply plan for the Kansas City BPU based on the demand and energy forecast prepared in 2008 and considering alternative natural gas fueled generation resources capable of meeting the BPU's need for firm generating capacity. The power supply plan was developed in two phases with Phase I of this study consisting of the comparison of 10 alternative generation expansion plans using simple cycle combustion turbines and/or combined cycle units. The Regional Haze Rule and the ozone non-attainment conditions in the Kansas City metropolitan area and their potential impacts on existing BPU generators are considered in this study. The study period is the 10-year period beginning 2008 through 2017.

This Power Supply Plan addresses the future power supply needs of the BPU's native load customers, plus the wholesale power sales commitments under existing contracts through the term of this study. The Power Supply Plan also considers the age and ability of the existing BPU generators to continue providing the level of economic and reliable service they have provided over the past 35 or more years. Phase I of the Power Supply Study includes the following elements:

- Forecast Need for Power--A comparison of BPU's 2008 electric load forecast to the forecast of the capabilities and costs of existing BPU generators and power purchases to produce a forecast of the timing and size of additional generating capacity needs.
- Characterization of New Power Supply Resources--Description of the new combustion turbine-based power supply resources available to the BPU including simple and combined cycle combustion turbines.
- Alternative Capacity Expansion Plans--The identification of alternative plans to meet the 2008-2017 generating capacity and energy needs.
- Financial Comparison of Alternative Power Supply Plans--The comparison of these plans on a comparative revenue requirement basis.
- An economic evaluation of issues that could affect normally expected (Base Case) forecasts of load growth and costs for fuel and air emissions (sensitivities).
- Conclusions and recommendations for a selected power supply plan.

Phase II of this study consists of refined modeling and the development of a BPU financial forecast based on the selected power supply plan and a cost-of-service study to forecast the impact on rates to retail customers by customer class. Included in the financial forecast were the latest forecast of capital requirements for the existing generators as well as the expected costs of new environmental regulations to the extent they require capital and operating cost additions to BPU's existing generators.

3.0 Forecast Need for Power

The forecast need for additional generation capacity for the BPU system is a function of projected load growth, the future capacity of BPU's existing generation fleet, firm sales of capacity and energy, and firm purchases of capacity and energy currently under contract. Using the latest available population forecast from the Mid America Regional Council and other non-residential development as a basis, the forecast of Net System Energy requirements for the BPU system is projected to increase at an average rate of 0.78 percent per year over the next 10 years from 2,559 GWh in 2008 to 2,745 GWh in 2017. The forecast of normal weather peak demand is also projected to increase at an average rate of 0.72 percent per year from 512 MW forecast for 2008 to 546 MW by 2017. BPU's projected capacity requirements increase from 582 MW in 2008 to 620 MW in 2017, with a 12 percent capacity margin requirement.

The future capacity of existing generators is an issue for this study primarily because after the existing 12 MW CT1, the existing Q1 is the next unit in line for eventual retirement. Q1 is facing increased maintenance costs and may be required to add new air emission control technology to meet future regulatory mandates. The early retirement of Quindaro Unit 1 is a subject of this study and one group of plans evaluate its retirement in 2011 instead of adding new emission control technology. In another group of plans, Quindaro Unit 1 operates throughout the 10-year study period with air quality control equipment added. One of BPU's existing combustion turbine units, CT1, is currently projected to retire during the planning period in 2015.

Continued difficulties obtaining firm transmission service for BPU's existing power purchase arrangement with the Southwest Power Administration (SWPA) have led to the assumption that this 38 MW resource will not be available to BPU on a firm basis until 2010. The 4 MW Western Area Power Administration (WAPA) power purchase, has firm transmission service, and is considered available throughout the study period. In addition, 2 MW of firm capacity is included in association with BPU's purchase of 25 MW of wind generation capacity from the Smoky Hills Wind Farm. The ongoing Nearman 1 Participation Sales agreements with the Columbia, Missouri Electric Department and with the Kansas Municipal Energy Agency are included in the 10-year forecast of BPU's need for power. A 50 MW summer capacity purchase from The Empire District Electric Company in 2008 has also been included in the forecast need for power.

Table 3-1 tabulates the resultant forecast balance of loads and resources for the BPU system for the scenario where Quindaro Unit 1 is retired early in 2011. Table 3-2 tabulates the resultant balance of loads and resources assuming the continued operation of Q1 through 2017. The resulting need for additional generating capacity based on the capacity requirements and capacity of existing supply resources can be seen in Figures 3-1 and 3-2. From the forecast shown in Table 3-1, we can see that if Quindaro Unit 1 is retired early in 2011, the system will have a capacity deficit of 73 MW in 2011 increasing up to 107 MW in 2017. In Table 3-2 if Quindaro Unit 1 continues to operate through 2017 as currently planned, the system will have a capacity deficit of 11 MW in 2011 increasing up to 35 MW by 2017.

Figures 3-1 and 3-2 illustrate the forecast loads and resources for the scenarios where Quindaro Unit 1 is retired early in 2011 and where Quindaro Unit 1 continues to operate through the planning period, respectively.

Table 3-1
Forecast Balance of Loads and Resources - BPU System
Quindaro Unit 1 Retired Early in 2011

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
System Peak Demand	512	515	519	526	528	532	537	542	544	546
System Capacity Responsibility[(a)]	582	585	590	598	600	605	610	616	618	620
Accredited Generating Capacity (Net of Station Service)										
Quindaro #1, Coal	72	72	72							
Quindaro #2, Gas	16	16	16	16	16	16	16	16	16	16
Quindaro #2, Coal	95	95	95	95	95	95	95	95	95	95
Nearman #1	235	235	235	235	235	235	235	235	235	235
Combustion Turbine #1, Gas	12	12	12	12	12	12	12			
Combustion Turbine #2, Oil	56	56	56	56	56	56	56	56	56	56
Combustion Turbine #3, Oil	51	51	51	51	51	51	51	51	51	51
Combustion Turbine #4 Gas & Oil	75	75	75	75	75	75	75	75	75	75
Total Installed Generation	**612**	**612**	**612**	**540**	**540**	**540**	**540**	**528**	**528**	**528**
Purchases										
SWPA Hydro	0	0	38	38	38	38	38	38	38	38
WAPA Hydro	4	4	4	4	4	4	4	4	4	4
Smoky Hills Phase 1	2	2	2	2	2	2	2	2	2	2
Summer Capacity Empire Purchase from Iatan	50									
Future Summer Capacity Purchases										
Total Existing Capacity Purchases	**56**	**6**	**44**	**44**	**44**	**44**	**44**	**44**	**44**	**44**
Nearman #1 Participation Sales										
Columbia	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20
KMEA	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38
Total Capacity Sales	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**
Total System Capacity[(b)]	**609**	**559**	**597**	**525**	**525**	**525**	**525**	**513**	**513**	**513**
Capacity Balance[(c)]	**97**	**44**	**78**	**-1**	**-3**	**-7**	**-12**	**-29**	**-31**	**-33**
Percent Capacity Balance (%)[(d)]	**16%**	**8%**	**13%**	**0%**	**-1%**	**-1%**	**-2%**	**-6%**	**-6%**	**-6%**
Capacity Surplus/(Deficit)[(e)]	**27**	**-26**	**7**	**-73**	**-75**	**-80**	**-85**	**-103**	**-105**	**-107**

Capacity Margin: 12%.

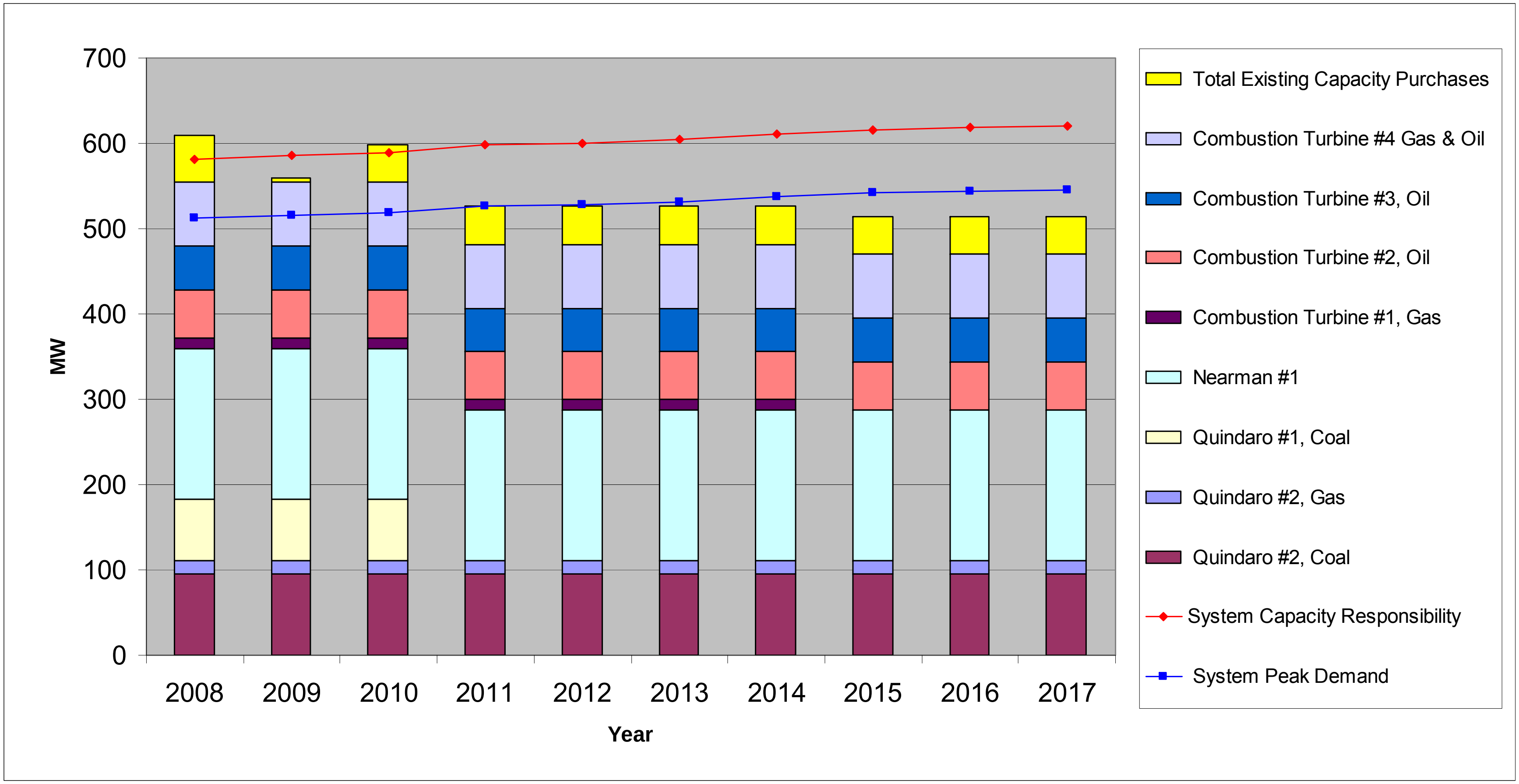
[(a)]System Capacity Responsibility = System Peak Demand/1-% Capacity Margin/100)).
[(b)]Total System Capacity = Total Generation + Total Capacity Purchases - Total Capacity Sales.
[(c)]Capacity Balance = Total System Capacity - System Peak Demand.
[(d)]Percent Capacity Balance = Capacity Balance/Total System Capacity) x 100.
[(e)]Capacity Surplus Deficit) = Total System Capacity - System Capacity Responsibility.

Table 3-2
Forecast Balance of Loads and Resources - BPU System
Quindaro Unit 1 Continues Operating Throughout Study Period

Description	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
System Peak Demand	512	515	519	526	528	532	537	542	544	546
System Capacity Responsibility (a)	582	585	590	598	600	605	610	616	618	620
Accredited Generating Capacity (Net of Station Service)										
Quindaro #1, Coal	72	72	72	72	72	72	72	72	72	72
Quindaro #2, Gas	16	16	16	16	16	16	16	16	16	16
Quindaro #2, Coal	95	95	95	95	95	95	95	95	95	95
Nearman #1	235	235	235	235	235	235	235	235	235	235
Combustion Turbine #1, Gas	12	12	12	12	12	12	12			
Combustion Turbine #2, Oil	56	56	56	56	56	56	56	56	56	56
Combustion Turbine #3, Oil	51	51	51	51	51	51	51	51	51	51
Combustion Turbine #4 Gas & Oil	75	75	75	75	75	75	75	75	75	75
Total Installed Generation	**612**	**612**	**612**	**612**	**612**	**612**	**612**	**600**	**600**	**600**
Purchases										
SWPA Hydro	0	0	38	38	38	38	38	38	38	38
WAPA Hydro	4	4	4	4	4	4	4	4	4	4
Smoky Hills Phase 1	2	2	2	2	2	2	2	2	2	2
Summer Capacity Empire Purchase from Iatan	50									
Future Summer Capacity Purchases										
Total Capacity Purchases	**56**	**6**	**44**	**44**	**44**	**44**	**44**	**44**	**44**	**44**
Nearman #1 Participation Sales										
Columbia	-20	-20	-20	-20	-20	-20	-20	-20	-20	-20
KMEA	-38	-38	-38	-38	-38	-38	-38	-38	-38	-38
Total Capacity Sales	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**	**-58**
Total System Capacity (b)	**609**	**559**	**597**	**597**	**597**	**597**	**597**	**585**	**585**	**585**
Capacity Balance (c)	**97**	**44**	**78**	**71**	**69**	**65**	**60**	**43**	**41**	**39**
Percent Capacity Balance (%) (d)	**16%**	**8%**	**13%**	**12%**	**12%**	**11%**	**10%**	**7%**	**7%**	**7%**
Capacity Surplus/(Deficit) (e)	**27**	**-26**	**7**	**-1**	**-3**	**-8**	**-13**	**-31**	**-33**	**-35**

Capacity Margin: 12%.

Notes:
(a) System Capacity Responsibility = System Peak Demand/1-% Capacity Margin/100)).
(b) Total System Capacity = Total Generation + Total Capacity Purchases - Total Capacity Sales.
(c) Capacity Balance = Total System Capacity - System Peak Demand.
(d) Percent Capacity Balance = Capacity Balance/Total System Capacity) X 100.
(e) Capacity Surplus Deficit) = Total System Capacity - System Capacity Responsibility.



Resource Capacities:

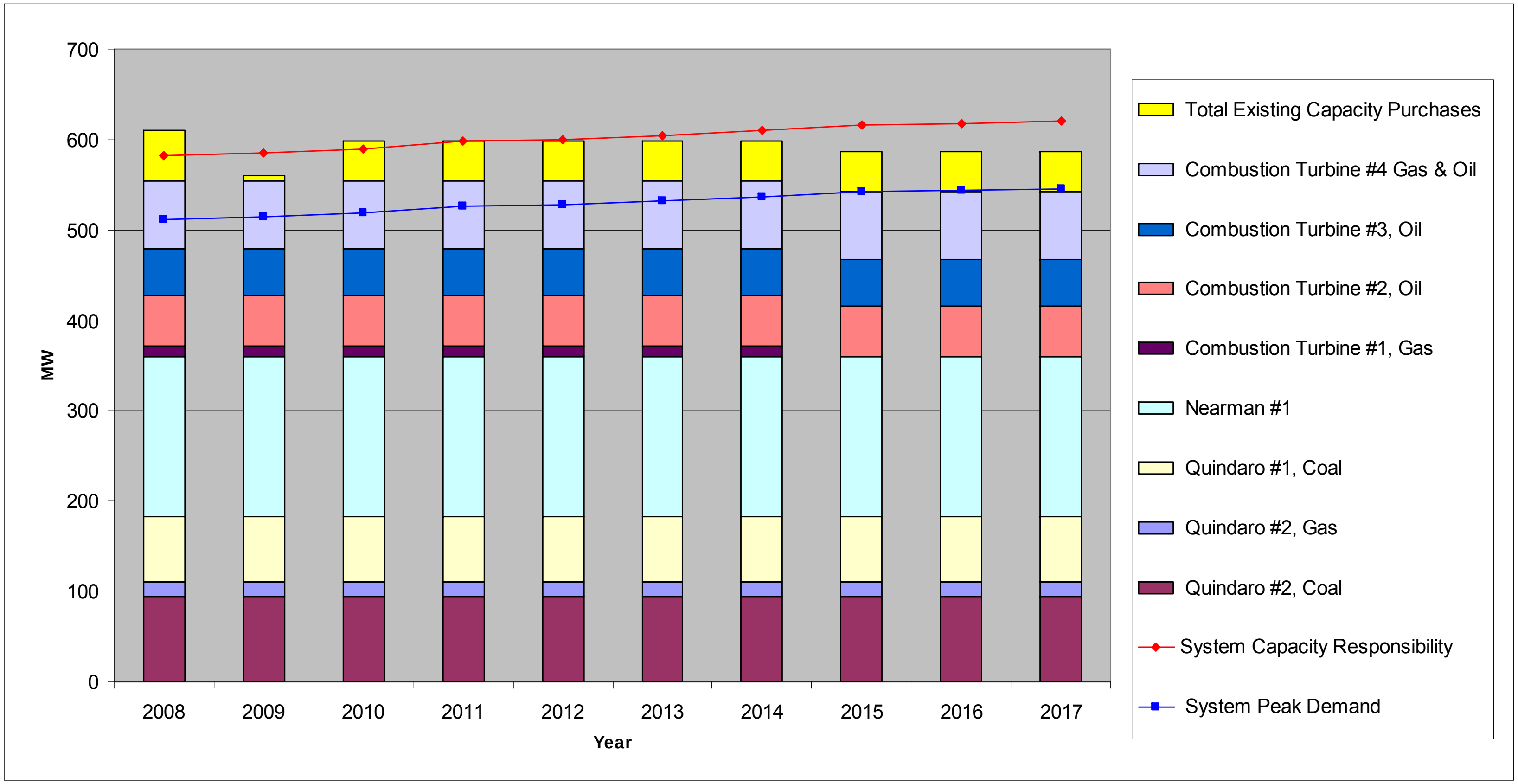
CT 4 - 75 MW
CT 3 - 51 MW
CT 2 - 56 MW
CT 1 - 12 MW

Nearman Unit 1 (BPU share) - 177 MW
Quindaro Unit 2 - 111 MW (16 MW gas, 95 MW coal)
Quindaro Unit 1 - 72 MW

Existing Capacity Purchases:

Summer 2008 Empire Capacity Purchase – 50 MW
SWPA – 38 MW (beginning in 2010)
WAPA – 4 MW
Smoky Hills Wind – 2 MW

Figure 3-1
Forecast Balance of Loads and Resources - Quindaro Unit 1 Retired in 2011



Resource Capacities:

CT 4 - 75 MW
CT 3 - 51 MW
CT 2 - 56 MW
CT 1 - 12 MW

Nearman Unit 1 (BPU share) - 177 MW
Quindaro Unit 2 - 111 MW 16 MW gas, 95 MW coal)
Quindaro Unit 1 - 72 MW

Existing Capacity Purchases:

Summer 2008 Empire Capacity Purchase – 50 MW
SWPA – 38 MW (beginning in 2010)
WAPA – 4 MW
Smoky Hills Wind – 2 MW

Figure 3-2
Forecast Balance of Loads and Resources - Quindaro Unit 1 Retiring after 2017

4.0 Future Power Supply Options

Alternative power supply options considered in this study for meeting BPU's need for capacity and energy consist of both simple and combined cycle combustion turbine generator additions. The following simple and combined cycle resource options were considered in this study:

- LM6000PC-Sprint Simple Cycle Combustion Turbine (SCCT).
- 2x1 LM6000PC-Sprint Combined Cycle Combustion Turbine (CCCT).
- 7EA SCCT.
- 1x1 7EA CCCT.
- LM2500 SCCT.

Detailed descriptions of the operating characteristics, capital costs, and operating costs for each of these options are contained below.

The characteristics include estimates of performance (output and heat rates), emissions, and capital and operation and maintenance (O&M) costs. New estimates of performance, emissions, capital costs and O&M maintenance costs were developed to account for changes in LM6000PC-Sprint CTG technology since the original estimates were developed in 2006. This section is organized into the following subsections:

- Section 4.1 - Performance and Emission Estimates.
- Section 4.2 - EPC Capital Cost Estimates.
- Section 4.3 - Operations and Maintenance Cost Estimates.

4.1 Performance and Emissions Estimates

This section contains performance and emission estimates for the combustion turbine technology options listed previously. Assumptions used to develop the performance and emission estimates are provided.

4.1.1 Estimating Assumptions

Performance and emission estimates for both the SCCT and CCCT options were developed using the indicated assumptions. Temperatures used for performance estimates are based on average daily temperatures during anticipated operation. The following seasons and temperatures were used:

SCCT:

- Spring/Fall: February, March, October, and November - 53° F.
- Summer: May 1 to September 30 - 90° F.
- Winter: Need for SCCTs during Winter season is negligible.

- CCCT:
  - Summer: May 1 to September 30 - 83° F.
  - Spring/Fall/Winter: October 1 to April 30 - 50° F.

The following unit arrangement criteria were used during the development of the performance and emission estimates.

- SCCT:
  - Evaporative inlet cooling.
  - Primary fuel is natural gas, back-up fuel is No. 2 fuel oil.
  - No Selective Catalytic Reduction (SCR) nor CO catalyst.
- CCCT:
  - Evaporative inlet cooling.
  - Duct firing capacity is sized to restore the summer day steam turbine generator output to the winter day output without duct firing. The steam turbine generator and steam cycle equipment are sized for the winter day steaming capacity of the heat recovery steam generator without duct firing in operation.
  - Wet mechanical draft cooling tower for Rankine Cycle heat rejection.
  - Primary fuel is natural gas, back-up fuel is No. 2 fuel oil.
  - Includes SCR but no CO catalyst.

4.1.2 Performance Estimates

Full and partial load performance estimates were generated for two seasonal ambient conditions for both the SCCT and CCCT unit. Performance estimates are provided in Tables 4-1 and 4-2 for the SCCT and CCCT technology options, respectively. Operating conditions for each of the cases are defined in a case summary at the top of each of the tables.

4.1.3 Emission Estimates

Full load emission estimates were generated for one seasonal ambient condition for both the SCCT and CCCT technology options. Emission estimates include oxides of nitrogen (NO_X) as nitrogen dioxide (NO_2), sulfur dioxide (SO_2), carbon monoxide (CO), carbon dioxide (CO_2), volatile organic compounds (VOC), and particulate matter of 10 microns or less (PM_{10}). Emission estimates are provided on a unitized basis. Emission estimates are provided in Table 4-3 and 4-4 for the SCCT and CCCT technology options, respectively.

Table 4-1
SCCT Performance Estimates

Case Summary	Spring/Fall			Summer		
Elevation, ft amsl	750	750	750	750	750	750
Dry Bulb Temperature, ° F	53	53	53	90	90	90
Relative Humidity, percent	60	60	60	60	60	60
Evaporative Cooling, On/Off	Off	Off	Off	On	On	On
Load, percent	100	75	50	100	75	50
LM6000PC-Sprint						
Gross CTG Output, kW	49,030	36,780	24,520	43,830	32,880	21,930
Auxiliary Load, kW	500	430	370	440	390	330
Net Plant Output, kW	48,530	36,350	24,150	43,390	32,490	21,600
Net Plant Heat Rate (LHV), Btu/kWh	8,608	9,103	10,297	8,716	9,346	10,683
Net Plant Heat Rate (HHV), Btu/kWh	9,563	10,113	11,440	9,683	10,383	11,868
LM2500PE						
Gross CTG Output, kW	23,080	17,320	11,550	21,390	16,060	10,710
Auxiliary Load, kW	240	180	120	220	170	110
Net Plant Output, kW	22,840	17,140	11,430	21,170	15,890	10,600
Net Plant Heat Rate (LHV), Btu/kWh	9,943	10207	11,431	9,993	10,492	11,738
Net Plant Heat Rate (HHV), Btu/kWh	11,047	11340	12701	11,103	11657	13043
GE 7EA						
Gross CTG Output, kW	83,500	62,600	41,600	75,700	56,800	37,800
Auxiliary Load, kW	1,000	900	600	900	1,800	600
Net Plant Output, kW	82,500	61,700	41,000	74,800	55,000	37,200
Net Plant Heat Rate (LHV), Btu/kWh	10,587	11,471	13,982	10,860	11,917	14,521
Net Plant Heat Rate (HHV), Btu/kWh	11,746	12,727	15,513	12,050	13,222	16,112

Notes:
1. Performance data is based on GE turbine estimating software Application for Package Power Solutions (APPS).
2. Estimates are reflective of new and clean conditions and do not included the effects of degradation.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. Performance estimates in this table do not include SCR or CO catalyst.
5. The evaporative cooler is assumed to operate with 85% effectiveness when in operation.
6. The average ambient temperature in the spring/fall, 53° F, and the accredited temperature in summer, 90° F, are based on International Station Meteorological Climate Summary, Ver 3.0 March 1995.
7. All data is expected, and not guaranteed, and does not include allowances for margins.

Table 4-2
CCCT Performance Estimates

Case Summary	Spring/Fall/Winter			Summer		
Elevation, ft amsl	750	750	750	750	750	750
Dry Bulb Temperature, ° F	50	50	50	83	83	83
Relative Humidity, percent	60	60	60	60	60	60
Evaporative Cooling, On/Off	Off	Off	Off	On	Off	Off
Duct Firing, On/Off	Off	Off	Off	On	Off	Off
Load, percent	100	75	50	100	75	50
2x1 LM6000PC-Sprint						
Gross CTG Output, kW	98,580	73,950	49,310	89,740	64,770	43,200
Gross STG Output, kW	28,760	22,210	17,720	28,760	21,230	17,460
Gross Plant Output, kW	127,350	96,160	67,040	118,510	86,010	60,660
Auxiliary Load, kW	2,840	2,580	2,350	2,770	2,500	2,300
Net Plant Output, kW	124,520	93,580	64,690	115,750	83,510	58,370
Net Plant Heat Rate (LHV), Btu/kWh	6,753	7,118	7,735	6,871	7,239	7,899
Net Plant Heat Rate (HHV), Btu/kWh	7,503	7,908	8,594	7,634	8,043	8,776
1x1 GE 7EA						
Gross CTG Output, kW	83,460	62,600	41,730	76,580	55,420	36,950
Gross STG Output, kW	44,960	39,560	35,790	44,950	39,190	34,270
Gross Plant Output, kW	128,420	102,160	77,520	121,530	94,610	71,220
Auxiliary Load, kW	3,140	2,810	2,420	3,050	2,710	2,430
Net Plant Output, kW	125,280	99,350	75,100	118,480	91,900	68,790
Net Plant Heat Rate (LHV), Btu/kWh	7,005	7,268	7,734	7,238	7,495	8,079
Net Plant Heat Rate (HHV), Btu/kWh	7,752	8,043	8,558	8,010	8,294	8,940

Notes:
1. Performance and emission data were based on Thermoflow and Application for Package Power Solutions (APPS).
2. Estimates are reflective of new and clean conditions and do not include the effects of degradation.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. It is assumed that there would be an SCR but no CO catalyst.
5. The average day time high temperature in the winter, 50° F, and in the summer, 83° F, are based on International Station Meteorological Climate Summary, Ver 3.0 March 1995.
6. The evaporative cooler is assumed to operate with 85% effectiveness when in operation.
7. Duct firing capacity is sized to restore the summer day steam turbine generator output to the winter day output.
8. A wet mechanical draft cooling tower is assumed for Rankine Cycle heat rejection.
9. All data is expected, and not guaranteed, and does not include allowances for margins.

Table 4-3
SCCT Emission Estimates

	NO_x, as NO_2		SO_2	CO		CO_2	VOC		PM_{10}
	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu
LM6000 PC-Sprint	25	0.1	0.0005	18	0.04	128	0.4	0.0006	0.026
LM2500 PE	25	0.1012	0.0006	48	0.1178	128	2.2	0.0031	Unavailable
7EA	9	0.04	0.0005	25.3	0.06	128	1.5	0.002	0.01

Notes:

1. Emission estimates are based on 100 percent load operation at an elevation of 750 ft amsl, a dry bulb temperature of 53° F, a relative humidity of 60 percent, and no evaporative cooling.
2. The dry air composition assumed for emission estimates is 0.98% Ar, 78.03% N_2 and 20.99% O_2.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. Emissions data is reflective of a unit without post combustion emissions controls.
5. ppm is pounds per million dry volume at 15 percent O_2.
6. Emissions in lb/MBtu are based on a LHV of fuel input.
7. PM_{10} emissions shown are total emissions (including filterable and condensable particulates).
8. The above estimates are on the assumption that NO_x is controlled through water injection.
9. The VOC/UHC ratio is assumed to be 20% (typical for GE turbines).
10. The SO_2 emission values provided consider that all fuel sulfur was converted to SO_2 with no additional oxidation.
11. CO_2 emissions are based on estimated B&V calculations and are typically not provided by the gas turbine manufacturer.
12. All data is expected, not guaranteed, and does not include allowances for margins.

Table 4-4
CCCT Emission Estimates

	NO_x, as NO_2		SO_2	CO		CO_2	VOC		PM_{10}
	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu
2x1 LM6000 PC-Sprint	2.0	0.01	0.0006	30	0.07	128	0.6	0.0009	0.027
1x1 7EA	2.0	0.01	0.0006	25.5	0.06	128	1.5	0.002	0.010

Notes:
1. Emission estimates are based on 100 percent load operation at an elevation of 750 ft amsl, a dry bulb temperature of 50° F, a relative humidity of 60 percent, no evaporative cooling, and no duct firing.
2. The dry air composition assumed for emission estimates is 0.98% Ar, 78.03% N_2 and 20.99% O_2.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. Emissions data is reflective of a unit with an SCR.
5. SCR reduces NO_x to an emission level of 2.0 ppmvd at 15% O_2.
6. ppm is pounds per million dry volume at 15 percent O_2.
7. Emissions in lb/MBtu based on LHV of fuel input.
8. The VOC/UHC ratio is assumed to be 20% (typical for GE turbines).
9. The SO_2 emission values provided consider that all fuel sulfur was converted to SO_2 with no additional oxidation.
10. PM_{10} emissions shown are total emissions (including filterable and condensable particulates).
11. PM_{10} emissions listed in this table are for turbine performance only and does not include particulate matter coming off the cooling tower. PM_{10} emissions from the cooling tower are estimated to represent no more than 33% of turbine emissions. However, since there is no cost associated with particulate matter emissions, this increment does not affect the results of the economic evaluation presented in this report..
12. CO_2 emissions are based on estimated B&V calculations and are typically not provided by the gas turbine manufacturer.
13. All data is expected, not guaranteed, and does not include allowances for margins.

4.2 EPC Capital Cost Estimates

This section provides capital cost estimates for the Combustion Turbine Generator (CTG) technology options outlined previously. Assumptions used to develop the cost estimates are provided below.

4.2.1 Estimating Assumptions

Capital cost estimates for both the SCCT and CCCT units were developed using the same assumptions used in the initial Kansas City BPU Future Generation Planning Technology Study completed in June of 2006.

Capital cost estimates for both the SCCT and CCCT units were developed based on a turnkey engineering, procurement, and construction (EPC) method of contracting, which is exclusive of Owner's costs. Typically, the scope of work for an EPC capital cost estimate is the base plant, which is defined as being "within the fence." Subsection 4.2.3 provides an overview of potential Owners' cost, which are not included in the EPC capital cost estimates.

Assumptions specific to the development of the EPC capital cost estimates are as follows:

- **SCCT General Assumptions**--The following general assumptions were used for the SCCT estimate:
  - The site will be a brownfield site and will be reasonably level and clear with no wetlands. The unit will be an add-on unit to the existing brownfield site. Demolition of any existing structures should be included in Owner's costs.
  - The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down, and staging.
  - Each plant estimate will feature one dual fueled CTG. The primary fuel will be natural gas and the backup fuel will be No 2 fuel oil. The cost of unloading and delivery to the project site is included. The facility site is assumed to be capable of being expanded for duplicate units.
  - The CTG includes a standard sound enclosure.
  - Spread footings were assumed for all equipment foundations. Stabilization of the existing subgrade is not anticipated.
  - Any buildings are pre-engineered.

  - The source of water for inlet air fogging system will be city water. If existing water treatment system is not adequate, demineralized water will be provided using an onsite contracted demineralizer trailer(s). A demineralization system is not included.
  - A sanitary sewer system is not included. It was assumed that a sanitary treatment system exists, or a sanitary sewer is located at the project boundary.
  - Construction power is available at the site boundary.
  - Natural gas supply was assumed to be supplied from a pipeline connection at the plant site boundary at the appropriate conditions that meet the CTG vendor requirements. Provision of a natural gas pipeline, compression station, etc., if required, will be included in the Owner's cost (not included here).
  - Fuel oil will be delivered by truck to the storage tank. It was assumed that the existing fuel oil unloading, storage, and forwarding system is sufficient for the added unit. It was assumed that the fuel oil storage facility is capable of 48 hours of full-load operation of the combustion turbine.
  - Substation and power transmission lines should be included in the Owner's costs.
  - A field-erected demineralized water storage tank is included.
  - Fire protection will consist of the CTG vendor's standard fire suppression system. Fire protection for major transformers will be a water deluge system.
  - Protection or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species, or historical, cultural, and archaeological artifacts is not included.
- **CCCT General Assumptions**--The following general assumptions were used for the CCCT estimate:
  - The site will be a brownfield site and will be reasonably level and clear with no wetlands. The unit will be an add-on unit to the existing brownfield site. Demolition of any existing structures should be included in Owner's costs.
  - The site has sufficient area available to accommodate construction activities including, but not limited to, offices, lay-down area, and staging.

- The plant will feature dual fueled CTG(s), heat recovery vapor generators (HRSGs) with duct burners, and one condensing STG. The primary fuel will be natural gas and the back-up fuel will be No. 2 fuel oil.
- The CTG(s) will include a standard enclosure. A gantry or bridge crane for servicing the CTG(s) is not included.
- The HRSG(s) will include duct (or supplementary) firing for restoring steam turbine generator output at hot day ambient conditions.
- Bypass dampers and stacks are not included.
- SCR equipment to control NO_x emissions is included.
- Pilings are included under major equipment. Spread footings were assumed for all other foundations. Further stabilization of the existing subgrade is not included.
- The source of water for cooling tower makeup, steam cycle makeup, and inlet air fogging system (if applicable) will be city water.
- It was assumed that the existing water treatment system (clarification and demineralization) will be sufficient.
- A sanitary sewer system is not included. It was assumed that a sanitary treatment system exists, or a sanitary sewer is located at the project boundary.
- Construction power and water is assumed to be available at the site boundary.
- Natural gas supply was assumed to be supplied from a pipeline connection at the plant site boundary at the appropriate conditions that meet the CTG vendor requirements. Provision of a natural gas pipeline, compression station, etc., if required, will be included in the Owner’s cost (not included here). No. 2 fuel oil will be delivered by truck to a fuel oil storage tank sized for 3 full-load days’ operation of the unit.
- An allowance for a substation is included in the cost estimate. Transmission lines are not included in the base plant cost estimate. This cost will be included in the Owner’s cost, if required.

- Automatic fire protection will consist of the CTG Original Equipment Manufacturer (OEM) supplied standard CO_2 fire suppression system, water deluge of the transformers, dry pipe fire protection of the cooling tower, under turbine sprinkler system, sprinkler systems in the buildings except in the control room which will have fire detection equipment only and hydrant protection for site.
- A wet, mechanical draft cooling tower will provide cycle heat rejection.
- Field-erected tanks will consist of a demineralized water storage tank.
- A wastewater collection system is included.
- An emergency diesel generator for safe shutdown is included.
- An auxiliary boiler is not included.
- Protection or relocation of existing fish and wildlife habitat, wetlands, threatened and endangered species, or historical, cultural, and archaeological artifacts is not included.

- **Direct Cost Assumptions**--The following direct cost assumptions were used for both the SCCT and CCCT unit:
  - Total direct capital costs are expressed in first quarter 2008 dollars.
  - Escalation is not included. Estimates are "overnight"* cost estimates to allow for the evaluation of alternative commercial operation dates for the project. Escalation can be included to adjust this assumption based on a schedule provided by the Owner for commercial operation of the unit.
  - Direct costs include the costs associated with the purchase of equipment, erection, and contractors' services.
  - The labor composite wage rate was based on an estimate of current wage rates for a northeastern Kansas site. The average composite wage rate includes burden, which includes fringe benefits, payroll taxes, and social security.

*The overnight cost is frequently used when estimating the cost to build a power plant. It is the cost of construction if no interest was incurred during construction, as if the project was completed "overnight" and it assumes that all the equipment is purchased today at today's cost, and all the construction is completed overnight. In reality, costs are spread out over the entire construction period and the costs when equipment is procured may have escalated since the "overnight" estimate was made. Therefore, allowances for interest, escalation, and other owner's costs are added to the overnight cost estimates to obtain an estimate of total installed cost.

- Construction costs were based on a turnkey EPC philosophy. Construction is assumed to be performed based on a 50 hour workweek. Construction indirect and construction equipment costs are included in the construction and service contracts portion of the estimate.
- Spare parts for startup are included. Spare parts for use during operation should be included in the Owner's costs.
- Permitting and licensing should be included in the Owner's costs.

• **Indirect Cost Assumptions**--The following items of cost are included in the base cost estimate for both the SCCT and CCCT units:

- General indirect costs including all necessary services required for checkouts, testing services, and commissioning.
- Insurance including builder's risk and general liability.
- Engineering and related services costs.
- Field construction management services including field management staff with supporting staff personnel, field contract administration, field inspection and quality assurance, and project control.
- Technical direction and management of startup and testing, cleanup expense for the portion not included in the direct cost construction contracts, safety and medical services, guards and other security services, insurance premiums, performance bond, and liability insurance for equipment and tools.
- Contractors' contingency and profit.
- Transportation costs for delivery to the jobsite.
- Startup/commissioning spare parts.
- Contingency for direct and indirect costs.

4.2.2 EPC Capital Cost Estimates

Overnight EPC capital cost estimates are provided in Tables 4-5 and 4-6 for the SCCT and CCCT technology options, respectively. These estimates are based on Black & Veatch's recent experiences and observations of the energy industry. The estimates are screening level, overnight estimates and were developed using the assumptions outlined in the previous sections. The estimates are provided in first quarter 2008 dollars.

Table 4-5
SCCT EPC Capital Cost Estimate

	LM6000PC-Sprint	LM2500PE	7EA
Direct Costs, $1,000			
Purchase Contracts			
Civil/Structural	750	500	850
Mechanical	21,150	14,010	24,300
Electrical	3,600	2,390	5,340
Control	80	50	70
Chemical	20	10	260
Subtotal Purchase Contracts	25,600	16,960	30,820
Construction Contracts			
Civil/Structural Construction	1,250	830	1,830
Mechanical/Chemical Construction	2,350	1,560	1,580
Electrical/Control Construction	700	460	875
Service Contracts/Construction Indirects	2,100	1,390	3,310
Subtotal Construction Contracts	6,400	4,240	7,595
Total Direct Costs	32,000	21,200	38,415
Indirect Costs, $1,000			
Engineering Costs	2,500	1,660	1,955
Construction Management	1,250	820	915
Other Indirects (includes project contingency)	6,520	4,320	7,565
Total Indirect Costs	10,270	6,800	10,435
Net Plant Output, kW	43,390	21,390	74,800
EPC Capital Cost, $1,000	42,270	28,000	48,850
Unit EPC Capital Cost, $/kW	974	1,390	653

Notes:
1. Estimates are screening level overnight estimates in first quarter 2008 dollars.
2. Net plant output and Unit EPC Capital Cost based on performance estimates at the accredited summer temperature, 90° F.

Table 4-6
CCCT EPC Capital Cost Estimate

	2x1 LM6000PC-Sprint	1x1 7EA
Direct Costs, $1,000		
Purchase Contracts		
Civil/Structural	2,800	6,200
Mechanical	67,490	49,600
Electrical	8,400	6,720
Control	1,020	1,310
Chemical	740	1,070
Subtotal Purchase Contracts	80,450	64,900
Construction Contracts		
Civil/Structural Construction	7,800	9,235
Mechanical/Chemical Construction	8,100	11,435
Electrical/Control Construction	4,700	5,320
Service Contracts/Construction Indirects	5,800	5,895
Subtotal Construction Contracts	26,400	31,885
Total Direct Costs	106,850	96,785
Indirect Costs, $1,000		
Engineering Costs	15,200	14,660
Construction Management	4,970	4,325
Other Indirects (includes project contingency)	22,700	20,730
Total Indirect Costs	42,870	39,715
Net Plant Output, MW	115,750	118,480
EPC Capital Cost, $1,000	149,720	136,500
Unit EPC Capital Cost, $/kW	1,293	1,152

Notes:
1. Estimates are screening level overnight estimates in first quarter 2008 dollars
2. Net plant output and Unit EPC Capital Cost for the 2x1 LM6000PC-Sprint and the 1x1 7EA based on performance estimates at the average day time high temperature in the summer, 83° F.

4.2.3 Potential Owner's Cost

The sum of the EPC capital cost and the Owner's cost equals the total project cost or the total capital requirement for the project. A generic list of Owner's costs that may apply is provided in Table 4-7. These costs are not usually included in the EPC capital cost estimate and should be considered by the project developer to determine the total capital requirement for the project. Owner's cost items include costs for "outside the fence" physical assets, project development, financing costs and at times unique inside the fence costs. The order of magnitude of these costs is project-specific and can vary significantly, depending upon technology and project-unique requirements. For a screening-level analysis, the Owner's cost, exclusive of interest during construction (IDC), can be estimated as a percentage of the EPC cost, which is a total of direct and indirect costs. Typically, based on actual project financial data, Owner's costs exclusive of IDC have been found to be in the range of 10 to 20 percent of the EPC capital cost for SCCT projects and 15 to 30 percent for CCCT projects.

4.3 Operation and Maintenance Cost Estimates

This section provides non-fuel O&M cost estimates consisting of fixed operation and maintenance (FOM) costs and variable operation and maintenance (VOM) costs for the CTG technology options outlined previously. Assumptions used to develop the cost estimates are provided below. The estimates of O&M cost are provided in Subsection 4.3.2.

4.3.1 Estimating Assumptions

O&M cost estimates for both the SCCT and CCCT unit were updated using the same methodology used in the initial Kansas City BPU Future Generation Planning Technology Study completed in June of 2006. All assumptions used in the development of the estimates, as provided in Subsection 3.1.1, are applicable to the O&M cost estimates.

All assumptions used in the development of the performance estimates are applicable to the O&M cost estimates. Additional assumptions specific to the development of the FOM and VOM were made.

Fixed O&M costs for both the SCCT and CCCT units were estimated based on the units being "add-on units" at an existing brownfield power generation station. Fixed O&M costs consist primarily of labor costs. Labor costs were calculated based on an assumed plant operator base salary of $65,000/year plus 40 percent in benefits and

Table 4-7
Potential Owner's Costs
Generic

Project Development:
- Site assessment study
- Land purchase/options/rezoning
- Major land modifications and preparation.
- Transmission/gas pipeline rights-of-way
- Off-site road modifications/upgrades
- Demolition (if applicable)
- Air quality & other environmental permitting/offsets
- Public relations/community development
- Legal assistance

Utility Interconnections:
- Natural gas service (if applicable)
- Gas system upgrades (if applicable)
- Gas compression (if applicable)
- Electrical transmission (if required)
- Supply water (if required)
- Wastewater/sewer (if required)

Spare Parts and Plant Equipment:
- Air quality control systems (AQCS) materials, supplies, and parts
- Combustion turbine and steam turbine materials, supplies, and parts
- HRSG materials, supplies, and parts
- Balance-of-plant equipment materials, supplies, and parts
- Rolling stock
- Plant furnishings and supplies
- Operating spares

Owner's Project Management:
- Preparation of bid documents and selection of contractors and suppliers
- Provision of project management
- Performance of engineering due diligence
- Provision of personnel for site construction management

Plant Startup/Construction Support:
- Owner's site mobilization
- O&M staff training
- Supply of trained operators to support equipment testing and commissioning
- Initial test fluids and lubricants
- Initial inventory of chemicals/reagents
- Consumables
- Cost of fuel not recovered in power sales
- Auxiliary power purchase
- Construction all-risk insurance
- Acceptance testing

Taxes/Advisory Fees/Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Power Purchase Agreement (PPA)
  - Interconnect agreements
  - Contracts--procurement and construction
  - Property transfer

Owner's Contingency:
- Owner's uncertainty and costs pending final negotiation:
- Unidentified project scope increases
- Unidentified project requirements
- Costs pending final agreement (e.g., interconnection contract costs)

Financing:
- Development of financing sufficient to meet project obligations or obtaining alternate sources of funding
- Financial advisor, lender's legal, market analyst, and engineer
- Interest during construction
- Loan administration and commitment fees
- Debt service reserve fund

Miscellaneous
- All costs for above-mentioned contractor-excluded items, if applicable

overhead. According to the particular needs of each generator, other plant personnel were included at relative base salary. Additionally, five percent (5%) overtime was applied to all non-salary positions. It is assumed that staffing plans between the existing unit and add-on unit(s) would overlap.

Variable nonfuel O&M costs primarily consist of the combustion turbine outage maintenance cost, which is driven by the number of operating hours for aeroderivative units and number of starts for frame units. CTG outage maintenance costs include both repair and replacement of components and were based on GE maintenance recommendations and listed prices. The possibility of firing distillate fuel was not factored into the outage maintenance costs. The O&M cost estimates for CCCT configurations include costs associated with an SCR, but do not include costs for a CO catalyst.

Additional assumptions relative to both the FOM and VOM costs are provided in Table 4-8.

Table 4-8
General O&M Cost Estimating Assumptions

Annual Capacity Factor, percentage	
SCCT	10
CCCT	50
Annual Number of Starts, starts/year	
SCCT	120
CCCT	52
Unit Assumptions	
Annual Plant Operator Base Salary Burden Rate (40%), $/year	65,000
SCR Catalyst Cost, $/ft^3	283
Water Cost, $/kGal	1.01
Anhydrous Ammonia Cost*, $/ton	600

*In SCR as applied for all CCCTs.

4.3.2 O&M Cost Estimates

O&M cost estimates are provided in Tables 4-9 and 4-10 for the SCCT and CCCT technology options, respectively.

Table 4-9
SCCT O&M Cost Estimates

	LM6000PC-Sprint	LM2500PE	7EA
Fixed Costs, $1,000/Yr			
Staffing, count	5	5	5
Labor	490.4	490.4	490.4
Maintenance	54.6	38.5	71.5
Other Expenses	69.5	59.1	77.2
Total Fixed Costs	614.5	587.9	639.1
Variable Costs, $1,000/Yr			
Outage Maintenance	109.3	90.3	223
Utilities	12.4	8.5	3.6
Chemical Usage	0	3.7	0
Total Variable Costs	121.7	102.5	227
Net Plant Output, kW	43,390	21,110	74.782
Annual Generation, MWh	38,000	18,492	65,509
Unit Fixed Cost, $/kW	14.16	27.85	8.55
Unit Variable Costs, $/MWh	3.2	5.54	3.46

Notes:
1. Net plant output based on the accredited temperature in the summer, 90° F.
2. Unit costs based on the net plant output at the accredited temperature in the summer and an assumed annual capacity factor of 10 percent.

Table 4-10
CCCT O&M Cost Estimate

	2x1 LM6000PC-Sprint	1x1 7EA
Fixed Costs, $1,000/Yr		
Staffing, count	17	12
Labor	1,609	1179.4
Maintenance	215	203.8
Other Expenses	223	171.6
Total Fixed Costs	2,047	1554.6
Variable Costs, $1,000/Yr		
Outage Maintenance	1,275	523.4
Utilities	188	240.8
Chemical Usage	259	341.9
Total Variable Costs	1,722	1106
Net Plant Output, MW	115,750	118,480
Annual Generation, MWh	507,000	518,942
Unit Fixed Cost, $/kW	17.68	13.12
Unit Variable Costs, $/MWh	3.40	2.13

Notes:
1. Net plant output based on thermal performance estimates at the average day time high temperature in the summer, 83° F.
2. Unit costs based on the net plant output at the average day time high temperature in the summer and an assumed annual capacity factor of 50 percent.

5.0 Alternative Capacity Expansion Plans

Based on the need for additional generating capacity and the net plant output estimates of the candidate generators, Black & Veatch and BPU personnel identified ten generation expansion plans for comparison on a 10-year forecast basis. New CTG and combined cycle generators (CCG) were available for selection from 2011 onwards. These plans were developed to meet BPU's customer requirements using self generation due to the transmission constraints in the SPP. The plans were hypothesized for purposes of considering the impact of the potential early retirement of Q1 in lieu of major capital expenditures for air quality control equipment should air quality regulations require these expenditures for continued operation of Q1 in 2011 and beyond.

Table 5-1 lists the expansion plans compared for this study.

Table 5-1
Generating Capacity Expansion Plans

SCENARIO 0: Q1 retires in 2011				SCENARIO 1: Q1 not retired during planning period			
Plan	**Net Generation**	**Unit Additions**	**Year**	**Plan**	**Net Generation**	**Unit Additions**	**Year**
Q0-A	**118 MW**	7EA CT	2011	**Q1-A**	**75 MW**	7EA CT	2011
		Convert to CC (1x1)	2012				
Q0-B	**130 MW**	LM6000 CT	2011	**Q1-B**	**43 MW**	LM6000 CT	2011
		Convert CT4 to CC (1x1)	2011				
		LM6000 CT	2015				
Q0-C	**116 MW**	(2) LM6000 CT	2011	**Q1-C**	**43 MW**	LM2500 CT	2011
		Convert to CC (2x1)	2013			LM2500 CT	2015
Q0-D	**118 MW**	7EA CT	2011	**Q1-D**	**44 MW**	Convert CT4 to CC (1x1)	2011
		LM6000 CT	2013				
Q0-E	**130 MW**	(2) LM6000 CT	2011				
		LM6000 CT	2013				
Q0-F	**118 MW**	LM6000 CT	2011				
		7EA CT	2012				

Notes:
1. Unless otherwise noted, assumed retirement of existing units are as follows: CT1 - Year 2015
2. CT4 is an existing 7EA SCCT

6.0 Financial Comparison of Alternative Plans

The initial criterion for the comparison of the alternative capacity expansion plans is the Net Present Value of Comparative Revenue Requirements. This comparative evaluation does not consider all costs common to all plans.

Comparative revenue requirements are defined to include the amortized capital costs associated with all new generation additions and new pollution control equipment for the existing coal units, system-wide energy production costs and wholesale economy energy purchases. They are net of proceeds from wholesale economy energy sales and are also net of the proceeds from the sale of Nearman #1 participation power under the existing wholesale contracts. System-wide production costs consist of fuel, fixed and variable O&M costs including unit startup costs, and air emission costs for all new and existing generators. Debt service associated with existing plants is not included because these costs are expected to be the same for all plans. Similarly, transmission, distribution, and customer service costs are not included because these costs are also assumed to be the same for all expansion plans. For purposes of amortizing the capital costs of alternative generators, the following finance periods and capital charge rates were assumed:

- Combined cycle, financed over 25 years--9.36 percent.
- Combustion turbine, financed over 20 years--10.52 percent.

Table 6-1 shows the forecast of comparative revenue requirements over the ten-year study period for plan Q1-B. A complete set of tables for all plans are included in Appendix B. Variable O&M, fixed O&M, economy purchases, emission allowances, and amortized capital costs are summed and credited with proceeds from economy energy sales and participation sales contracts to produce comparative revenue requirements for the 10-year period 2008 through 2017. Cumulative comparative revenue requirements are shown in the far right column and levelized annual values for each cost or credit column are shown at the bottom of Table 6-1. Levelized values are Present Worth Discount Rate (PWDR) weighted averages over the 10 forecast years. For purposes of the initial expansion plan comparison, BPU's capacity and energy needs prior to 2011 were assumed to be met by short-term (possibly yearly) purchases priced in accordance with the forecast of spot market prices.

The lower right corner of Table 5-1 contains the resultant cumulative present worth (CPW) of comparative revenue requirements for BPU's lowest cost plan over the 2008 - 2017 planning period.

Table 6-1
Comparative Annual Revenue Requirements – LM6000 Addition in 2011, Quindaro 1 Retires After 2017

Q1-B: Add LM6000 in 2011, Q1 Retires after 2017

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)	AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461	Q1 SCR	33,877	25	01/01/2012	38,894	6,437
						Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
						N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
						N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015		

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs*[4] *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$78,411	$3,781	$36,548	$5,504	-$6,079	$7,279	-$15,771	$0	$109,674	$5,461	$5,802	$11,262	$120,936	$389,834
2012	2,644	$81,739	$4,565	$38,557	$13,608	-$6,483	$10,280	-$14,707	$0	$127,558	$5,461	$12,238	$17,699	$145,258	$508,206
2013	2,669	$83,390	$4,873	$40,087	$14,507	-$6,221	$13,743	-$14,818	$0	$135,561	$5,461	$12,238	$17,699	$153,261	$626,871
2014	2,697	$90,054	$7,362	$43,662	$14,123	-$7,236	$8,653	-$16,415	$0	$140,203	$5,461	$31,773	$37,234	$177,437	$757,401
2015	2,721	$95,059	$7,611	$44,334	$15,628	-$8,033	$8,878	-$16,717	$0	$146,761	$5,461	$31,773	$37,234	$183,994	$886,003
2016	2,733	$96,684	$7,691	$45,169	$17,202	-$7,651	$10,835	-$17,072	$0	$152,858	$5,461	$31,773	$37,234	$190,091	$1,012,240
2017	2,744	$99,404	$7,823	$45,931	$19,006	-$8,460	$12,145	-$17,326	$0	$158,522	$5,461	$31,773	$37,234	$195,756	$1,135,754
Levelized Cost($1000):		$79,639	$5,174	$38,968	$10,809	-$6,543	$10,934	-$15,547	$0	$123,434	$3,521	$14,496	$18,016	$141,450	
NPV:		$639,447	$41,548	$312,886	$86,792	-$52,538	$87,790	-$124,829	$0	$991,096	$28,268	$116,390	$144,658	$1,135,754	
Levelized Cost($/MWh):		$24.07	$1.56	$11.78	$3.27	-$1.98	$3.31	-$4.70	$0.00	$37.31	$1.06	$4.38	$5.45	$42.76	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

6.1 Forecast Fuel Prices

The forecasts of natural gas and coal prices delivered to BPU generators were developed from the Spring 2008 Electricity and Fuel Price Outlook long-term forecast, overlaid with the April 2008 short-term forecast from Ventyx for North Southwest Power Pool (SPP). The short-term forecast goes out two years (April, 2008 through March, 2010). The same Ventyx forecasts of fuel prices was used to drive the Ventyx forecast of North SPP power market prices and the forecast of emission allowance prices used in the BPU expansion plan comparisons in order to maximize consistency. BPU's estimates for expected local distribution costs for natural gas and local rail service for coal based on future contract adjustments were added to the Ventyx forecast to provide total delivered prices to each of the BPU generators. Figure 6-1 shows a comparison of fuel costs for natural gas and coal for the BPU generating plants.

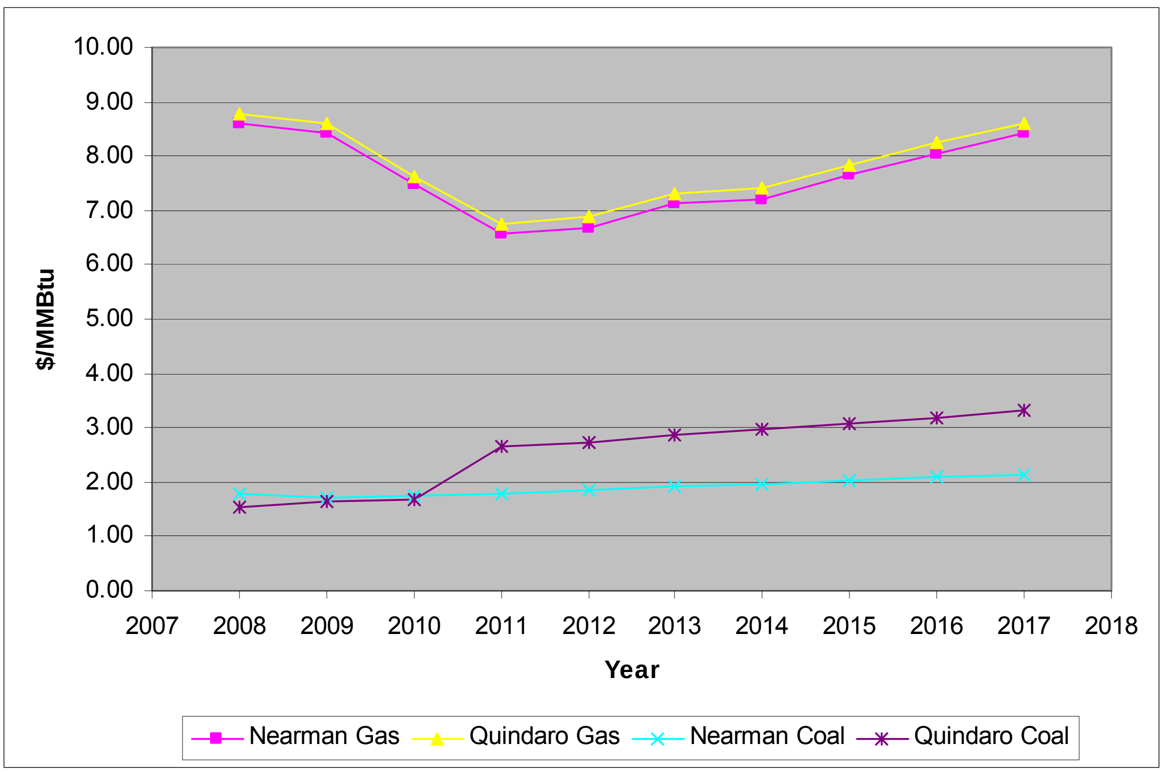


Figure 6-1
Annual Average Fuel Price Forecasts Delivered to BPU Generators

6.2 Environmental Compliance Costs

As stated in Section 3.0, future environmental requirements associated with Quindaro Unit 1 may have a significant impact on the selection of a generation expansion plan over the next 10 years. While the impact of new emission controls for Quindaro Unit 1 was analyzed in this study, the initial assumption is that the unit will operate through the 10-year study period. For purposes of testing the impact of new NO_x emission controls on Quindaro Unit 1, B&V estimated the capital cost for adding SCR to Q1 to be $34 million in 2008 dollars. Unless otherwise noted, all expansion plans and sensitivity cases that retire Q1 by 2011 exclude the SCR cost and all plans that retain Q1 beyond 2017 assume the expenditure for the Q1 SCR is made. Figure 6-2 shows the emission allowance prices forecast for SO_2 and CO_2 used in the study.

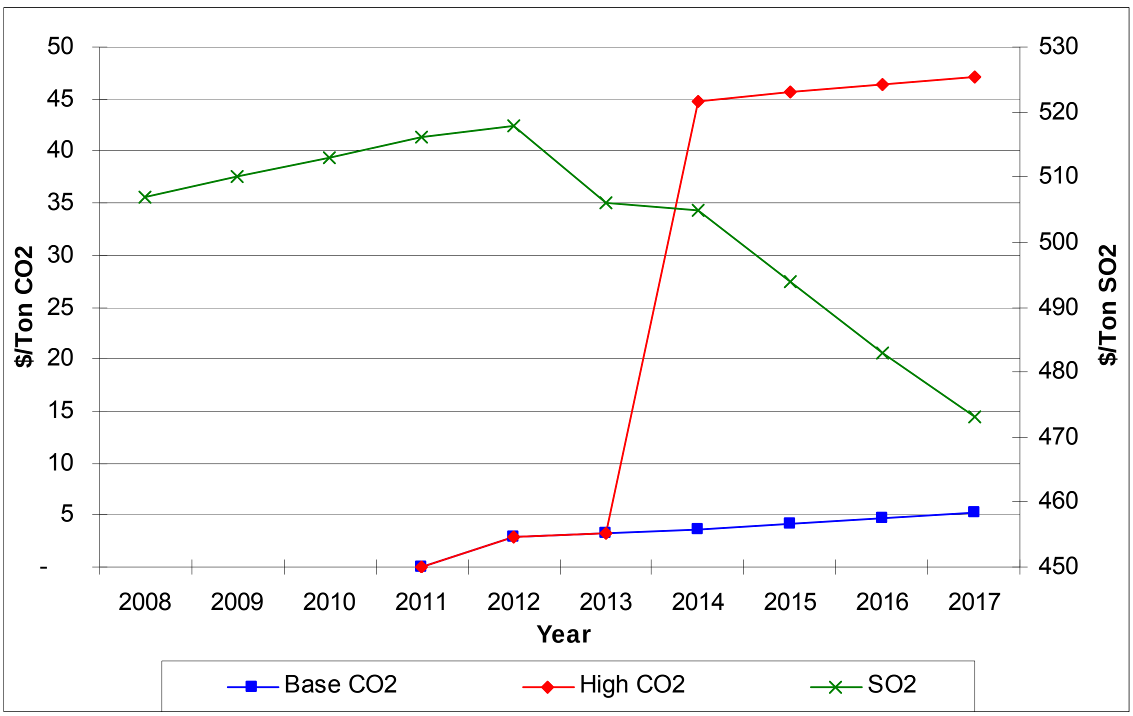


Figure 6-2
SO_2 and CO_2 Allowance Price Forecast - Nominal Dollars

B&V also estimated the capital cost related to the addition of Low NO_x Burners (LNB) and Overfire Air (OFA) to Quindaro Unit 2 and Nearman Unit 1 (N1) to be $10.7 million and $20.6 million respectively, measured in 2008 dollars. A Spray Dry Scrubber and Fabric Filter for N1 were estimated to require $110.2 million ($2008).

6.3 System-Wide Production Costs

B&V projected production revenue requirements for each expansion plan in Table 4-1 using the PROSYM production cost model developed by Ventyx. PROSYM simulated the economic commitment and dispatch of generators in each expansion plan and produced projections of production costs, including interchange power that were used to feed the revenue requirements model. Appendix A contains an overview description of the PROSYM model used for this study.

Production costs were estimated on an hourly chronological basis with BPU generating units dispatched to meet BPU loads considering opportunities to buy power from surrounding markets if interchange power can be obtained at a lower cost and considering opportunities to sell available capacity above BPU loads if the sales can be made at a profit.

Interchange purchases and sales were constrained based on BPU's experience with the maximum effective available capacity on the transmission lines connecting BPU to the surrounding power market. In most cases, BPU's ability to import or export power are determined by other systems transmission limitations within SPP. Market Purchases were limited to a maximum of 250 MW year round. It was assumed that on-peak economy purchases are available 80 percent of the time during non-summer months and 40 percent of the time during summer months (June through September, inclusive). Off-peak economy purchases were assumed to be available 95 percent of the time. Market sales were limited to 50 MW and assumed accessible 55 percent of the time.

6.4 Forecast of Hourly Interchange Prices

The Ventyx Spring 2008 long-term forecast overlaid with the Ventyx April 2008 short-term forecast of hourly interchange prices for the SPP electric market were used in the study and are shown in Table 6-2A. The corresponding market purchase transmission costs are included in Table 6-2B.

Table 6-2A
Projected Spot Market Prices in SPP North
$/MWh

	On-Peak	Off-Peak
2008	72.83	34.58
2009	74.70	36.31
2010	68.05	34.03
2011	62.96	32.96
2012	65.62	36.19
2013	68.44	36.37
2014	69.72	36.95
2015	73.66	37.85
2016	75.85	38.42
2017	77.52	38.82

Table 6-2B
Projected Market Purchase Transmission Costs in SPP North
$/MWh

	On-Peak	Off-Peak
2008	6.51	4.58
2009	6.64	4.67
2010	6.76	4.75
2011	6.88	4.84
2012	7.01	4.93
2013	7.13	5.02
2014	7.27	5.11
2015	7.39	5.20
2016	7.53	5.30
2017	7.68	5.39

6.5 Base Case Results

Table 6-3 contains a summary of the 2008-2017 levelized annual costs of ten expansion plans calling for BPU to add new LM2500, LM6000, or 7EA combustion turbine capacity and/or to convert the CTGs including BPU's existing 7EA (CT 4) to combined cycle. Costs are shown by major cost element such as fuel, O&M, economy purchases, emission allowances, amortized capital for new units, and new air quality controls for existing units. Proceeds from economy energy sales are also shown. Quindaro Unit 1 was assumed to be retired by 2011 in six plans which add between 118 and 130 MW of new capacity over the ten-year period. Quindaro Unit 1 continued to operate through the ten-year study period in four plans which add between 43 and 75 MW of new generating capacity. The expansion plans for which revenue requirements are forecast in Table 6-3 are the plans described in Section 5.0 of this report. These Base Case results reflect the comparative revenue requirements assuming the "expected" values of key inputs such as electrical loads, fuel, and spot market prices. Detailed revenue requirement forecasts for each of the Base Case Plans are contained in Appendix B to this report.

The first observation from Table 6-3 is that the three expansion plans with the lowest cumulative present worth revenue requirements were three plans that continued to operate Quindaro 1 through the planning period. Production costs for the continued operation of Q1 tended to be slightly lower than those for the early Q1 retirement plans because Q1 supplies energy at lower cost base load generation prices. In all early Q1 retirement scenarios Q1 energy is replaced with higher cost gas fired generation or wholesale market purchases also based on gas fired generation. In addition, the capital requirements tend to favor continued operation of Q1 because the amortized AQC capital costs associated with the continued operation of Q1 are generally lower than the amortized capital costs of the replacement capacity.

Of the three least-cost plans, the top plan, (Q1-B), adds an LM6000 combustion turbine in 2011 and the next best plan, (Q1-C), adds an LM 2500 in 2011 and again in 2013. The third best plan (Q1-A), adds a 7EA combustion turbine in 2011. The fourth and fifth ranked plans both call for the early retirement of Quindaro 1 and the addition of capacity to meet growth as well as the replacement of retired capacity with a 7EA simple cycle gas turbine. Plan Q0-D adds a 7EA CT in 2011 to replace Q1 and an LM6000 in 2013. Plan Q0-F adds the LM6000 in 2011 and a 7EA in 2012. The expansion plans that convert new or existing simple cycle combustion turbines to combined cycle combustion turbines are consistently the most expensive plans because the production cost savings associated with the efficiency of a combined cycle plant are not sufficient to offset a combined cycle's incremental capital cost.

Table 6-3
Levelized Annual Comparative Revenue Requirements by Expansion Plan - Base Case Conditions (Normally expected loads and costs)

Base Plans	Levelized Annual Production Cost								Levelized Annual Capital Cost			Levelized Total System Cost	Cumulative Present Worth Cost	Rank within Category	Rank within All Plans	% Difference From Least Cost Plan	
	Fuel Cost[1]	O&M Variable[2]	O&M Fixed	Emission Costs	Economy Sales	Economy[3] Purchase	Nearman Participant[4] Sales	Net Production Cost	Unit Additions Capital[5] Cost	AQC Capital Cost	Total Capital Cost						
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q1 Retires in 2011																	
Q0-A	$78,561	$5,439	$36,415	$9,506	$(5,202)	$16,596	$(15,546)	$125,770	$9,109	$11,033	$20,143	$145,912	$1,171,582	5	9	0.93%	3.15%
7EA CT in 2011 convert to CC in 2012 (118 MW)																	
Q0-B	$79,368	$5,569	$36,755	$9,532	$(5,685)	$14,749	$(15,547)	$124,741	$11,971	$11,033	$23,005	$147,745	$1,186,299	6	10	2.20%	4.45%
2 x LM6000 CT in 2011,2015 & CT4 CC in 2011 (130 MW)																	
Q0-C	$79,744	$5,324	$36,781	$9,547	$(5,788)	$14,521	$(15,547)	$124,583	$10,213	$11,033	$21,247	$145,829	$1,170,914	4	8	0.87%	3.10%
2 x LM6000CT in 2011 convert to CC in 2013 (116 MW)																	
Q0-D	$77,771	$4,810	$36,165	$9,509	$(4,352)	$18,902	$(15,546)	$127,259	$6,277	$11,033	$17,311	$144,570	$1,160,805	1	4	**0.00%**	2.21%
7EA CT in 2011 & LM6000 CT in 2013 (118 MW)																	
Q0-E	$79,703	$4,881	$36,589	$9,592	$(5,099)	$15,194	$(15,547)	$125,314	$9,264	$11,033	$20,298	$145,612	$1,169,169	3	7	0.72%	2.94%
3 x LM6000 CT in 2011 & 2013 (130 MW)																	
Q0-F	$78,160	$4,816	$36,230	$9,525	$(4,436)	$18,122	$(15,546)	$126,869	$6,788	$11,033	$17,821	$144,690	$1,161,766	2	5	**0.08%**	2.29%
LM6000CT in 2011 & 7EA CT in 2013 (118 MW)																	
Q1 Retires after 2017																	
Q1-A	$78,432	$5,152	$38,986	$10,779	$(6,303)	$12,931	$(15,546)	$124,432	$4,054	$14,496	$18,550	$142,981	$1,148,049	3	3	1.08%	1.08%
7EA CT in 2011 (75 MW)																	
Q1-B	$79,639	$5,174	$38,968	$10,809	$(6,543)	$10,934	$(15,547)	$123,434	$3,521	$14,496	$18,016	$141,450	$1,135,754	1	1	**0.00%**	**0.00%**
LM6000 CT in 2011 (43 MW)																	
Q1-C	$77,867	$5,068	$39,122	$10,743	$(5,876)	$12,931	$(15,546)	$124,309	$3,140	$14,496	$17,635	$141,944	$1,139,717	2	2	0.35%	0.35%
2 x LM2500 CT in 2011, 2013 (43 MW)																	
Q1-D	$79,680	$5,758	$39,262	$10,764	$(7,017)	$10,217	$(15,546)	$123,117	$7,232	$14,496	$21,727	$144,844	$1,163,005	4	6	2.40%	2.40%
CT4 CC in 2011 (44 MW)																	

[1] Fuel includes emergency purchase for energy not served by BPU.
[2] Variable O&M includes start-up and shut-down related maintenance costs.
[3] Economy Purchase includes Bridge Power purchase assumed to be at spot power prices.
[4] Includes Nearman 1 sales only.
[5] Capital costs are net of Nearman 1 Participation sales capacity proceeds.

A primary conclusion from the comparison of expansion plans in Table 6-3 is that if air quality regulations do require an SCR to be added to Quindaro Unit 1 in order for it to continue operating, it is still more cost effective to expend the capital on Q1 than to replace it with new generation, purchased power and the operation of BPU's more expensive gas fueled generators. Some equipment replacements to maintain reliability would be inevitable if the unit is to continue operating through the study period. From the comparison of the least-cost plan with Q1 retired in 2011 to the least-cost plan with AQC upgrades, it was determined that up to $30 million ($2008) could be spent on Q1 during the planning period before the continued operation of this unit is no longer economically justified. Clearly, if the Regional Haze Rule and/or Kansas City ozone attainment conditions do not require the addition of an SCR, the continued operation of Q1 and the addition of a combustion turbine to keep up with load growth would be the least-cost plan for BPU.

Another major conclusion from the results shown in Table 6-3 is that whether or not future costs for Q1 exceed the level that economically justifies its continued operation, both least cost plans call for the addition of a simple cycle combustion turbine in 2011. Furthermore, the costs of Plans Q0-D and Q0-F where Q1 is retired in 2011 and add either a 7EA or an LM6000 CT in 2011 are so close as to indicate that BPU should solicit bids for both frame and aero-derivative type turbines. In addition, the costs of Plans Q1-B and Q1-C where Q1 continues to operate through the study period are also very close and also call for either the addition of a LM6000 in 2011 or a LM 2500 turbine in 2011 and 2013. In all cases additional CT capacity is required.

6.6 Sensitivity/Risk Results

Each of the plans compared in Table 6-3 were also compared assuming changes in several future underlying conditions that could influence the comparisons. By seeking the least-cost plan under a variety of plausible future conditions, BPU should minimize the risk of adopting a plan that will later cost its customers more than necessary. Each of the plans in Table 6-3 was compared under the following sensitivity/risk scenarios:

- High and Low Load.
- High CO_2 tax.
- High fuel and market conditions.
- No Economy Purchases.

The high and low load scenarios reflect the potential impact of the loss or gain of a large 28 MW customer. The High CO_2 tax case reflects the impact of a market price for or tax on CO_2 emissions which jump from the Base Case assumption of approximately $3.25/ton in 2013 to $45/ton by 2014 and escalates at 1.8 percent thereafter. The high fuel price and electric market conditions reflect the high range of the coordinated forecasts for natural gas and electric market prices as presented by Ventyx in its Spring 2008 forecast. The No Economy Purchases scenario is with sales assumed to be made to the economy market but no economy purchases allowed as would be the extreme case if import transmission constraints became worse.

Table 6-4 lists the ranking of the ten plans under the base case assumptions of future conditions and under each of the sensitivity cases. Also shown in Table 6-4 is an aggregate ranking of plans under the Base Case and all sensitivity cases. As shown, the aggregate ranking under all sensitivities is nearly the same as the Base Case ranking. The loss or gain of a large customer and high fuel and market prices has little impact on the ranking of the four least-cost plans. Under all sensitivity cases the least-cost supply plan is Plan Q1-B that adds an SCR to Q1 in order to continue its operation and adds an LM6000 aero-derivative combustion turbine to meet growth. Even the high carbon tax scenario still favors the continued operation of Q1 and the addition of an LM 6000 in 2011.

Given the lower efficiency of the 7EA, the plans calling for the addition of a 7EA in 2011 in place of an LM6000, drop in rank from third and fourth place to fourth and tenth place in the cases that assume a high carbon tax and assume no economy purchases, respectively. While Plan Q1-D calling for the continued operation of Q1 and the conversion of existing CT 4 to combined cycle moves up to a third place ranking under the assumption of no economy purchases, it is still more expensive than the addition of an LM6000 CT or two LM2500s.

Should later investigations of Q1 reveal necessary expenditures that preclude its continued operation beyond 2011, the addition of a 7EA combustion turbine in 2011 is favored in most sensitivity scenarios except in the case of no economy purchases or a high carbon tax. In both of these cases, the addition of two LM6000 CTs followed by their conversion to combined cycle provides insurance against high CO_2 costs and higher power import constraints.

Table 6-4
Sensitivity/Risk Ranking of Alternative Plans

	Q0-A	Q0-B	Q0-C	Q0-D	Q0-E	Q0-F	Q1-A	Q1-B	Q1-C	Q1-D
	7EA CT in 2011 convert to CC in 2012	2 x LM 6000 CT in 2011, 2015 & CT4 CC in 2011	2 x LM6000CT in 2011 convert to CC in 2013	7EA CT in 2011 & LM6000 CT in 2013	3 x LM6000 CT in 2011 & 2013	LM6000CT in 2011 & 7EA CT in 2013	7EA CT in 2011	LM6000 CT in 2011	2 x LM2500 CT in 2011,2013	CT4 to CC in 2011
	118 MW	130 MW	116 MW	118 MW	130 MW	118 MW	75 MW	43 MW	43 MW	44 MW
Base Case	9	10	8	4	7	5	3	1	2	6
Lose Large Customer	8	10	9	4	6	6	3	1	2	5
Gain Large Customer	9	10	8	5	7	6	3	1	2	4
High Fuel and Market Price	9	10	8	5	7	6	3	1	2	4
High Carbon Tax	7	10	3	4	8	5	6	1	2	9
No Economy Purchases	7	8	5	10	6	9	4	1	2	3
Sum of Rank	49	58	41	32	41	37	22	6	12	31
Combined Rank	9	10	7	5	7	6	3	1	2	4

Note: Refer to Appendix C for detailed costs that determine these rankings.

7.0 Observations and Conclusions Resulting from Phase I Analysis

The following observations and conclusions are derived from the analyses in the previous sections of this report:

- BPU is projected to need between 35 and 107 MW of additional generating capacity to meet its capacity responsibility over the next 10 years depending on whether or not Quindaro Unit 1 remains in operation.
- Comparing the plans that continue Q1 operation with the plans that do not, even with a $34 million ($2008) expenditure for the addition of an SCR, it is less costly to continue to operate Q1 through 2017 than to retire it in 2011.
- In addition to the $34 million SCR, the BPU could afford to spend an additional $30 million ($2008) on reliability maintenance projects before it would be less costly to its customers to retire the unit.
- The least cost plan of the ten alternative plans is the one that adds an SCR to Q1, continues its operation and meets growth with the addition of an LM6000 aero-derivative turbine.
- The second and third least-cost plans add two LM2500 CTs in 2011 and a Frame 7EA CT in 2011, respectively.
- Regardless of whether or not Q1 is retired early, the NPV costs of plans that add a Frame 7EA turbine, an LM6000 turbine, or LM2500 turbines in 2011 are so close as to indicate that BPU should solicit bids for these types of machines.
- The continued operation of Q1 with an SCR is economical under a variety of sensitivity/risk scenarios and as in the Base Case, the least-cost additions to meet growth include a Frame 7EA, LM6000 CT, or two LM2500 CTs.
- Even a high carbon tax favors the continued operation of Q1.
- A high carbon tax and no economy purchases individually favor the use of the more efficient LM6000 CT over the 7EA.

- Should later investigations of Q1 reveal necessary expenditures greater than $30 million may preclude its continued operation beyond 2011, the addition of a 7EA combustion turbine in 2011 is favored in most sensitivity scenarios as the least expensive replacement capacity. However, in the case of no economy purchases or a high carbon tax, the addition of two LM6000 CTs followed by their conversion to combined cycle provides insurance against high CO_2 costs and higher power import constraints.

8.0 Phase II of Power Supply Study/Refinement

Results from Phase I of this study indicated that regardless of whether or not Q1 was retired early, the addition of a simple cycle combustion turbine is the best natural gas plan for enabling BPU to continue to supply its customers with reliable service at the least cost through 2017. Results from Phase I analysis also revealed that plans that keep Q1 in service are of lower cost than retiring Q1 in 2011. While these findings were consistent under a variety of sensitivity conditions, newly available forecasts of key planning inputs and assumptions suggested the need for a final comparison of selected plans in order to further firm up the decision to add a simple cycle combustion turbine and to provide the latest available inputs to the financial forecast and cost-of-service study.

Included in the Phase I assumptions were that the simple cycle combustion turbines, typically used during the highest load hours, would not run enough to require SCR to control NO_x emissions. Results from the Phase I production cost simulations revealed that the simple cycle combustion turbines may run enough hours to require an SCR for NO_x control. Accordingly, new performance, capital and operating cost estimates were developed for the simple cycle combustion turbine alternatives based on the units being configured with SCR. The updated cost and performance estimates were used in the Phase II analysis. Additionally, the Ventyx May 2008 updates to the natural gas and spot market energy price forecasts were used in the Phase II analysis, and the future annual capital expenditures for the existing BPU generators were forecast by BPU and included in the comparison of revenue requirements.

Plans carried forward for analysis in Phase II are the top five plans from the Phase I analysis. The top five plans consist of two plans in which Q1 retires in 2011 and three plans keeping Q1 in service through the end of the study period.

9.0 Phase II Expansion Plans

The plans considered in Phase II of the Power Supply Plan development were the five least-cost plans from the Phase I analysis. Assumed types and operation dates for new generator additions and Q1 retirement assumptions for each plan are contained in Table 9-1.

Table 9-1
Phase II Generating Capacity Expansion Plans

SCENARIO 0: Q1 retires in 2011				SCENARIO 1: Q1 not retired during planning period			
Plan	**Net Generation**	**Unit Additions**	**Year**	**Plan**	**Net Generation**	**Unit Additions**	**Year**
Q0-D	**118 MW**	7EA CT	2011	**Q1-A**	**75 MW**	7EA CT	2011
		LM6000 CT	2013				
Q0-F	**118 MW**	LM6000 CT	2011	**Q1-B**	**43 MW**	LM6000 CT	2011
		7EA CT	2012				
				Q1-C	**42 MW**	LM2500 CT	2011
						LM2500 CT	2015

Notes:
1. Assumed retirement of existing units for both scenarios are as follows: CT1 - Year 2015

10.0 Power Supply Options - Cost and Performance Updates

Updates to the Simple Cycle Combustion Turbines' cost and performance estimates to include SCR for NO_x control were developed for the Phase II analysis. The plans carried forward to the Phase II analysis contain the following units:

- LM6000PC-Sprint SCCT with SCR.
- 7EA SCCT with SCR.
- LM2500 SCCT with SCR.
- Updates to the operating characteristics, capital costs, and operating costs for each of these options are detailed in the following subsections. Consistent with the Phase I analysis, these characteristics include estimates of performance (output and heat rates), emissions, and capital and O&M costs.

10.1 Performance and Emissions Estimates

This section contains performance and emission estimates for the combustion turbine technology options listed previously. Assumptions used to develop the performance and emission estimates are provided.

10.1.1 Estimating Assumptions

The performance and emission estimates for the SCCT options were developed using the same assumptions used in Phase I of this study. The following seasons and temperatures were used:

- Spring/Fall: February, March, October, and November - 53° F (April was not included for estimation of Spring temperature)
- Summer: May 1 to September 30 - 90° F.
- Winter: Need for SCCTs during Winter season is negligible.

The following unit arrangement criteria were used during the development of the performance and emission estimates.

- Evaporative inlet cooling.
- Primary fuel is natural gas, back-up fuel is No. 2 fuel oil.
- SCR but no CO catalyst.

10.1.2 Performance Estimates

Full and partial-load performance estimates were generated for two seasonal ambient conditions. Performance estimates are shown in Table 10-1. Operating conditions are defined in a case summary in the top five rows of the table. When

Table 10-1
SCCT with SCR Performance Estimates

Case Summary	Spring/Fall			Summer		
Elevation, ft amsl	750	750	750	750	750	750
Dry Bulb Temperature, ° F	53	53	53	90	90	90
Relative Humidity, percent	60	60	60	60	60	60
Evaporative Cooling, On/Off	Off	Off	Off	On	On	On
Load, percent	100	75	50	100	75	50
LM6000PC-Sprint						
Gross CTG Output, kW	48,930	36,700	24,470	43,730	32,800	21,870
Auxiliary Load, kW	490	430	370	440	390	330
Net Plant Output, kW	48,440	36,270	24,100	43,290	32,410	21,540
Net Plant Heat Rate (LHV), Btu/kWh	8,625	9,125	10,326	8,736	9,369	10,716
Net Plant Heat Rate (HHV), Btu/kWh	9,582	10,138	11,473	9,705	10,409	11,906
LM2500PE						
Gross CTG Output, kW	23,030	17,280	11,520	21,330	16,010	10,680
Auxiliary Load, kW	240	180	120	220	170	110
Net Plant Output, kW	22,790	17,100	11,400	21,110	15,840	10,570
Net Plant Heat Rate (LHV), Btu/kWh	9,967	10,232	11,459	10,020	10,520	11,770
Net Plant Heat Rate (HHV), Btu/kWh	11,073	11,367	12,731	11,132	11,687	13,077
GE 7EA						
Gross CTG Output, kW	83,260	62,450	41,630	75,440	56,580	37,720
Auxiliary Load, kW	1,000	880	750	910	800	680
Net Plant Output, kW	82,260	61,570	40,880	74,530	55,780	37,040
Net Plant Heat Rate (LHV), Btu/kWh	10,610	11,507	14,035	10,887	11,961	14,584
Net Plant Heat Rate (HHV), Btu/kWh	11,761	12,784	15,593	12,096	13,289	16,203

Notes:
1. All data is expected, and not guaranteed, and does not include allowances for margins.
2. Performance was based on GE’s Gas Turbine Performance Estimator (GTPE).
3. Estimates are reflective of new and clean conditions and do not include the effects of degradation.
4. Fuel is assumed to be nearly 100% methane with 0.2 g/100 SCF sulfur.
5. The evaporative cooler is assumed to operate with 85% effectiveness when in operation.
6. Above performance estimates include the effect of a SCR but do not include the effect of a CO catalyst.
7. The dry-bulb temperature in the spring/fall, 53° F, and the accredited temperature in summer, 90° F, are based on International Station Meteorological Climate Summary, Ver 3.0 March 1995.

modeling these units it was assumed that their minimum outputs are the 50 percent load performance estimates shown in Table 10-1. As the output of these units decreases toward 50 percent, the NO_x emissions start to increase rapidly, so it is anticipated that these units will not spend more than a small amount of time operating below 50 percent of full output.

10.1.3 Emission Estimates

Full and part load emission estimates were generated for one seasonal ambient condition for the SCCT technology options considered in Phase II. Emission estimates include oxides of NO_x as NO_2, SO_2, CO, CO_2, VOC, and particulate matter of PM_{10}. Emission estimates are provided on a unitized basis. Updated full load emission estimates for the SCCT with SCR technology options are provided in Table 10-2.

Table 10-2
SCCT with SCR Emission Estimates

	NO_x, as NO_2		SO_2	CO		CO_2	VOC		PM_{10}
	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu	ppm	lb/MBtu	lb/MBtu
LM6000 PC-Sprint	2.5	0.01	0.0006	18	0.04	128	0.4	0.0006	0.008
LM2500 PE	2.5	0.01	0.0006	48	0.12	128	2.1	0.0031	0.014
7EA	2.5	0.01	0.0006	25.3	0.06	128	1.5	0.0021	0.010

Notes:
1. Emission estimates are based on 100 percent load operation at an elevation of 750 ft amsl, a dry bulb temperature of 53° F, a relative humidity of 60 percent, and no evaporative cooling.
2. The dry air composition assumed for emission estimates is 0.98% Ar, 78.03% N_2 and 20.99% O_2.
3. Fuel is assumed to be nearly 100 percent methane with a sulfur content of 0.2 grain per 100 SCF.
4. Emissions data shown include effects of a SCR but CO catalyst is not included.
5. NO_x emissions are assumed to be controlled to 2ppmvd at 15% O_2 in the SCR. Ammonia slip in the SCR is assumed to be 10 ppmvd at 15% O_2. Estimated ammonia slip is 6.2 lb/h for the LM6000, 3.4 lb/h for the LM2500, and 12.9 lb/h for the 7EA.
6. ppm is pounds per million dry volume at 15 percent O_2.
7. Emissions in lb/MBtu are based on a LHV of fuel input.
8. PM_{10} emissions shown are filterable and condensable particulate catch.
9. The above estimates are on the assumption that NO_x is controlled with SCR.
10. The VOC/UHC ratio is assumed to be 20% (typical for GE turbines).
11. The SO_2 emission values provided do not include oxidation through the gas turbine.
12. CO_2 emissions are based on estimated B&V calculations and are typically not provided by the gas turbine manufacturer.
13. All data is expected and is per stack, not guaranteed, and does not include allowances for margins.
14. Estimated stack flow is 605,694 acfm for the LM6000, 347,504 acfm for the LM2500, and 1,497,070 for the 7EA.

10.2 EPC Capital Cost Estimates

This section provides updates to the capital cost estimates for the CTG technology options considered in Phase II. The assumptions used to develop the capital costs are the same as used to develop the capital costs for Phase I with the exception that it is assumed that SCR will be required on the simple cycle units. An estimate of the cost of the SCR system is included in the capital cost used in the Phase II analysis.

10.2.1 EPC Capital Cost Estimates

An overnight EPC capital cost estimate summary is provided in Table 10-3 for the SCCT options. These estimates are based on Black & Veatch's recent experiences and observations of the energy industry. The estimates are screening level, overnight estimates and were developed using the assumptions outlined in the previous sections. The estimates are provided in first quarter 2008 dollars.

Table 10-3
SCCT with SCR EPC Capital Cost Estimate

	LM6000PC-Sprint	LM2500PE	7EA
Total EPC Costs, $1,000			
Net Plant Output, kW	43,290	21,110	74,530
EPC Capital Cost, $1,000	45,670	30,600	55,560
Unit EPC Capital Cost, $/kW	1,055	1,450	745

Notes:
1. Estimates are screening level overnight estimates in first quarter 2008 dollars.
2. Net plant output and Unit EPC Capital Cost based on performance estimates at the accredited summer temperature, 90° F.

10.3 Operation and Maintenance Cost Estimates

This section provides updated non-fuel O&M cost estimates consisting of FOM costs and VOM costs for the SCCT technology options considered in Phase II. Assumptions used to develop the cost estimates are provided in the Phase I section of this report with the exception that the O&M cost estimates for the SCCT configurations include costs associated with the units having SCR. O&M cost estimates for units including SCR are provided in Table 10-4.

Table 10-4
SCCT with SCR O&M Cost Estimates

	LM6000PC-Sprint	LM2500PE	7EA
Fixed Costs, $1,000/Yr			
Staffing, count	5	5	5
Labor	490.4	490.4	490.4
Maintenance	54.2	38.5	71.3
Other Expenses	69.4	59.1	77.2
Total Fixed Costs	614.0	587.9	638.9
Variable Costs, $1,000/Yr			
Outage Maintenance	134.5	90.3	256.3
Utilities	12.4	8.5	3.6
Chemical Usage	6.8	3.7	6.6
Total Variable Costs	153.7	102.5	266.4
Net Plant Output, kW	43,290	21,110	74,530
Annual Generation, MWh	37,922	18,492	65,288
Unit Fixed Cost, $/kW	14.18	27.85	8.57
Unit Variable Costs, $/MWh	4.05	5.54	4.08

Notes:
1. Net plant output based on the accredited temperature in the summer, 90° F.
2. Unit costs based on the net plant output at the accredited temperature in the summer and an assumed annual capacity factor of 10 percent.

11.0 Phase II Comparison of Alternative Plans

As in Phase I, the initial criterion for the comparison of the alternative capacity expansion plans in Phase II is the Net Present Value of Comparative Revenue Requirements. This comparative evaluation does not consider all the costs that are common to all the plans, such as debt service on existing units, electric distribution costs, and the electric utility's share of administrative and general costs which includes the electric utility's share of BPU's general manager's and other top management's salaries. However, it does include the major future annual capital expenditures associated with each existing BPU generator as forecast by BPU and shown in Table 11-1. These expenditures total $132 million over the 10-year study period. For plans in which Quindaro Unit 1 was assumed to be retired early, the ten-year capital expenditures for the existing generators would be reduced to $103 million.

There were not significant differences in the relative rankings of the plans between Phase I and Phase II. The plan that continues operation of Quindaro 1 through the study period and adds an LM6000 turbine in 2011 was still the plan with the lowest forecast of revenue requirements over the ten-year study period. A tabulation of the net present value costs of each plan by major cost category is contained in Table 11-2. The full comparative revenue requirement tables for each Phase II plan is contained in Appendix D to this report.

Each of the plans compared in Table 11-2 were also compared assuming changes in several future underlying conditions that could influence the comparisons. By seeking the least-cost plan under a variety of plausible future conditions, BPU should minimize the risk of adopting a plan that will later cost its customers more than necessary. Each of the plans in Table 11-2 was compared under the following sensitivity/risk scenarios:

- High and Low Load.
- High CO_2 tax.
- High fuel and market conditions.
- No Economy Purchases.

The relative ranking of the Phase II sensitivity runs is similar to the Phase I ranking. Table 11-3 shows the levelized annual summary for each of the sensitivities performed for each expansion plan analyzed. Table 11-3 summarizes the sensitivity results compared to the Phase II base case conditions. These results show that under base case conditions and all sensitivities that the least-cost 10-year expansion plan is the plan that retains Quindaro Unit 1 and adds an LM6000 or similar simple cycle combustion turbine in 2011.

Table 11-1
Electric Production Forecast Capital Expenditures - Existing Generators, $1,000

Year	Total Quindaro		Total CTs	Total Nearman	Total Electric Production		Comments
	Q1 Out of Service in 2011	with Q1			Q1 Out of Service in 2011	with Q1	
2008	12,282	12,282	0	4,474	16,756	16,756	Q2 Major Overhaul
2009	4,149	5,325	1,120	4,592	9,860	11,036	CT1 Major Overhaul
2010	1,630	4,822	4,436	4,548	10,614	13,806	CT2 & CT3 Majors
2011	1,540	17,108	0	3,438	4,978	20,546	Q1 Major Overhaul
2012	1,316	1,708	112	17,170	18,598	18,990	N1 Major Overhaul
2013	4,368	5,152	0	4,194	8,562	9,346	
2014	12,510	12,846	672	459	13,641	13,977	Q2 Major Overhaul
2015	2,688	3,360	0	6,552	9,240	9,912	
2016	2,912	3,472	0	5,846	8,758	9,318	
2017	1,288	7,896	0	369	1,657	8,265	Q1 Major Overhaul

Table 11-2
Levelized Annual Comparative Revenue Requirements by Expansion Plan - Phase II Base Case[1] Conditions

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	nit Addition	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 78,335	$ 5,071	$ 42,192	$ 18,796	$ (4,584)	$ 22,874	$ (18,036)	$ 9,739	$ 154,388	$ 8,131	$ 16,714	$ 24,844	$ 179,232	$ 1,439,121	1	4	**0.00%**	2.38%
Q0-F (SCR)	$ 78,148	$ 5,046	$ 42,258	$ 18,805	$ (4,570)	$ 22,570	$ (18,036)	$ 9,739	$ 153,960	$ 8,560	$ 16,714	$ 25,273	$ 179,233	$ 1,439,125	2	5	**0.00%**	2.38%
Q1-A (SCR)	$ 79,655	$ 5,458	$ 45,096	$ 21,483	$ (7,432)	$ 14,513	$ (19,971)	$ 12,210	$ 151,011	$ 4,997	$ 20,589	$ 25,586	$ 176,597	$ 1,417,962	3	3	0.88%	0.88%
Q1-B (SCR)	$ 79,750	$ 5,429	$ 45,519	$ 21,479	$ (7,545)	$ 13,502	$ (19,972)	$ 12,210	$ 150,371	$ 4,098	$ 20,589	$ 24,687	$ 175,058	$ 1,405,604	1	1	**0.00%**	**0.00%**
Q1-C (SCR)	$ 79,339	$ 5,385	$ 45,836	$ 21,401	$ (7,024)	$ 14,384	$ (19,972)	$ 12,210	$ 151,559	$ 4,027	$ 20,589	$ 24,615	$ 176,174	$ 1,414,566	2	2	0.64%	0.64%

Notes:
Phase II Base Case Conditions varied from Phase I Base Case Conditions as follows:

- Updated new unit performance, costs, and emissions estimates to include SCR in the unit configurations.
- Updated short-term natural gas and purchase power price forecasts.
- Added Nearman 1 scrubber landfill costs and moved Nearman 1 scrubber commercial operations date from 2013 to 2014.
- Added costs of ongoing equipment replacements for existing units.

Table 11-3
Phase II - Levelized Annual Comparative Revenue Requirements
by Expansion Plan - Sensitivity Cases

Lose Large Customer

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 74,794	$ 4,898	$ 42,192	$ 18,464	$ (5,548)	$ 18,936	$ (18,036)	$ 9,739	$ 145,438	$ 8,131	$ 16,714	$ 24,844	$ 170,282	$ 1,367,258	1	4	**0.00%**	2.00%
Q0-F (SCR)	$ 74,659	$ 4,878	$ 42,258	$ 18,473	$ (5,531)	$ 18,585	$ (18,036)	$ 9,739	$ 145,024	$ 8,560	$ 16,714	$ 25,273	$ 170,297	$ 1,367,375	2	5	**0.01%**	2.01%
Q1-A (SCR)	$ 76,034	$ 5,256	$ 45,096	$ 20,920	$ (8,280)	$ 11,607	$ (19,972)	$ 12,210	$ 142,870	$ 4,997	$ 20,589	$ 25,586	$ 168,456	$ 1,352,595	3	3	0.91%	0.91%
Q1-B (SCR)	$ 75,798	$ 5,219	$ 45,519	$ 20,902	$ (8,325)	$ 10,904	$ (19,972)	$ 12,210	$ 142,256	$ 4,098	$ 20,589	$ 24,687	$ 166,943	$ 1,340,448	1	1	**0.00%**	**0.00%**
Q1-C (SCR)	$ 75,582	$ 5,187	$ 45,836	$ 20,842	$ (7,881)	$ 11,548	$ (19,972)	$ 12,210	$ 143,350	$ 4,027	$ 20,589	$ 24,615	$ 167,966	$ 1,348,657	2	2	0.61%	0.61%

Gain Large Customer

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 82,336	$ 5,284	$ 42,298	$ 19,013	$ (3,541)	$ 27,776	$ (18,036)	$ 9,739	$ 164,870	$ 8,131	$ 16,714	$ 24,844	$ 189,715	$ 1,523,285	2	5	**0.04%**	2.78%
Q0-F (SCR)	$ 82,202	$ 5,269	$ 42,258	$ 19,021	$ (3,559)	$ 27,462	$ (18,036)	$ 9,739	$ 164,358	$ 8,560	$ 16,714	$ 25,273	$ 189,631	$ 1,522,614	1	4	**0.00%**	2.73%
Q1-A (SCR)	$ 83,831	$ 5,665	$ 45,203	$ 21,926	$ (6,119)	$ 17,917	$ (19,972)	$ 12,210	$ 160,662	$ 4,997	$ 20,589	$ 25,586	$ 186,248	$ 1,495,451	3	3	0.90%	0.90%
Q1-B (SCR)	$ 83,667	$ 5,627	$ 45,626	$ 21,879	$ (5,978)	$ 16,842	$ (19,972)	$ 12,210	$ 159,901	$ 4,098	$ 20,589	$ 24,687	$ 184,588	$ 1,482,124	1	1	**0.00%**	**0.00%**
Q1-C (SCR)	$ 83,651	$ 5,603	$ 45,942	$ 21,814	$ (5,677)	$ 17,802	$ (19,971)	$ 12,210	$ 161,373	$ 4,027	$ 20,589	$ 24,615	$ 185,989	$ 1,493,371	2	2	0.76%	0.76%

High NG and MCP

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 80,625	$ 5,014	$ 42,192	$ 18,678	$ (4,667)	$ 26,920	$ (18,036)	$ 9,739	$ 160,465	$ 8,131	$ 16,714	$ 24,844	$ 185,309	$ 1,487,913	2	5	**0.04%**	4.12%
Q0-F (SCR)	$ 80,286	$ 4,983	$ 42,258	$ 18,683	$ (4,592)	$ 26,632	$ (18,036)	$ 9,739	$ 159,953	$ 8,560	$ 16,714	$ 25,273	$ 185,227	$ 1,487,250	1	4	**0.00%**	4.07%
Q1-A (SCR)	$ 81,290	$ 5,440	$ 45,096	$ 21,442	$ (7,902)	$ 16,684	$ (19,971)	$ 12,210	$ 154,288	$ 4,997	$ 20,589	$ 25,586	$ 179,874	$ 1,444,275	3	3	1.06%	1.06%
Q1-B (SCR)	$ 80,915	$ 5,394	$ 45,519	$ 21,416	$ (7,937)	$ 15,751	$ (19,972)	$ 12,210	$ 153,296	$ 4,098	$ 20,589	$ 24,687	$ 177,983	$ 1,429,092	1	1	**0.00%**	**0.00%**
Q1-C (SCR)	$ 80,673	$ 5,372	$ 45,836	$ 21,369	$ (7,398)	$ 16,379	$ (19,972)	$ 12,210	$ 154,469	$ 4,027	$ 20,589	$ 24,615	$ 179,084	$ 1,437,931	2	2	0.62%	0.62%

High Carbon Tax

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 77,721	$ 5,020	$ 42,192	$ 73,110	$ (4,947)	$ 30,220	$ (18,036)	$ 9,739	$ 215,018	$ 8,131	$ 16,714	$ 24,844	$ 239,863	$ 1,925,943	1	3	**0.00%**	0.66%
Q0-F (SCR)	$ 77,531	$ 4,996	$ 42,258	$ 73,170	$ (4,937)	$ 29,879	$ (18,036)	$ 9,739	$ 214,602	$ 8,560	$ 16,714	$ 25,273	$ 239,875	$ 1,926,042	2	4	**0.01%**	0.67%
Q1-A (SCR)	$ 79,288	$ 5,413	$ 45,096	$ 82,626	$ (8,590)	$ 18,436	$ (19,971)	$ 12,210	$ 214,508	$ 4,997	$ 20,589	$ 25,586	$ 240,094	$ 1,927,800	3	5	0.76%	0.76%
Q1-B (SCR)	$ 79,259	$ 5,383	$ 45,519	$ 82,539	$ (8,721)	$ 17,378	$ (19,972)	$ 12,210	$ 213,595	$ 4,098	$ 20,589	$ 24,687	$ 238,282	$ 1,913,252	1	1	**0.00%**	**0.00%**
Q1-C (SCR)	$ 78,986	$ 5,346	$ 45,836	$ 82,281	$ (8,065)	$ 18,201	$ (19,972)	$ 12,210	$ 214,823	$ 4,027	$ 20,589	$ 24,615	$ 239,438	$ 1,922,534	2	2	0.49%	0.49%

No Economy Purchases

	Levelized Annual Production Cost									Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Existing	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Plant O&M	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Capital Cost	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q0-D (SCR)	$ 117,100	$ 6,569	$ 42,192	$ 20,361	$ (6,784)	$ -	$ (18,038)	$ 9,739	$ 171,138	$ 8,131	$ 16,714	$ 24,844	$ 195,983	$ 1,573,614	2	5	0.50%	5.37%
Q0-F (SCR)	$ 115,399	$ 6,585	$ 42,258	$ 20,375	$ (6,593)	$ -	$ (18,038)	$ 9,739	$ 169,726	$ 8,560	$ 16,714	$ 25,273	$ 194,999	$ 1,565,718	1	4	**0.00%**	4.84%
Q1-A (SCR)	$ 106,911	$ 6,537	$ 45,096	$ 22,400	$ (9,492)	$ -	$ (19,973)	$ 12,210	$ 163,688	$ 4,997	$ 20,589	$ 25,586	$ 189,274	$ 1,519,751	3	3	1.76%	1.76%
Q1-B (SCR)	$ 103,789	$ 6,464	$ 45,519	$ 22,137	$ (8,832)	$ -	$ (19,973)	$ 12,210	$ 161,314	$ 4,098	$ 20,589	$ 24,687	$ 186,001	$ 1,493,468	1	1	**0.00%**	**0.00%**
Q1-C (SCR)	$ 105,716	$ 6,505	$ 45,836	$ 22,108	$ (8,378)	$ -	$ (19,973)	$ 12,210	$ 164,024	$ 4,027	$ 20,589	$ 24,615	$ 188,640	$ 1,514,654	2	2	1.42%	1.42%

Table 11-4
Phase II - Sensitivity/Risk Ranking of Alternative Plans

Plan rankings based on Net CPW Cost								
	Base Case	Lose Large Customer	Gain Large Customer	High NG and MCP	High Carbon Tax	No Economy Purchases	**Average**	**Ranking**
Q0-D (SCR)	3	4	5	5	3	5	**4.2**	**4**
Q0-F (SCR)	5	5	4	4	4	4	**4.3**	**5**
Q1-A (SCR)	2	3	3	3	5	3	**3.2**	**3**
Q1-B (SCR)	3	1	1	1	1	1	**1.3**	**1**
Q1-C (SCR)	1	2	2	2	2	2	**1.8**	**2**
Plan rankings based on % higher than least cost plan								
Q0-D (SCR)	1.7%	2.0%	2.8%	4.1%	0.7%	5.4%	**2.8%**	**5**
Q0-F (SCR)	1.7%	2.0%	2.7%	4.1%	0.7%	4.8%	**2.7%**	**4**
Q1-A (SCR)	0.2%	0.9%	0.9%	1.1%	0.8%	1.8%	**0.9%**	**3**
Q1-B (SCR)	1.7%	0.0%	0.0%	0.0%	0.0%	0.0%	**0.3%**	**1**
Q1-C (SCR)	0.0%	0.6%	0.8%	0.6%	0.5%	1.4%	**0.6%**	**2**
Percent Higher than base case CPW Cost								
Q0-D (SCR)	0.0%	-5.0%	5.8%	3.4%	34%	9.3%	**9.5%**	**5**
Q0-F (SCR)	0.0%	-5.0%	5.8%	3.3%	34%	8.8%	**9.4%**	**4**
Q1-A (SCR)	0.0%	-4.6%	5.5%	1.9%	36%	7.2%	**9.2%**	**3**
Q1-B (SCR)	0.0%	-6.9%	3.0%	-0.7%	33%	3.8%	**6.4%**	**1**
Q1-C (SCR)	0.0%	-4.7%	5.6%	1.7%	36%	7.1%	**9.1%**	**2**

Plans	**Q1 Retires 2011**		**Q1 retires after 2017**		
	Q0-D	**Q0-F**	**Q1-A**	**Q1-B**	**Q1-C**
7EA CT	**2011**	**2012**	**2011**		
LM6000	**2013**	**2011**		**2011**	
LM2500					**2011 & 2015**

12.0 Observations and Conclusions Resulting from Phase II Analysis

The results of the Phase II analysis show that plan Q1-B, which is the plan that keeps Quindaro Unit 1 in service and adds an LM6000 (or similar simple cycle combustion turbine) in 2011 is the least cost 10-year expansion plan on a NPV basis. This plan is also the least cost on a NPV basis under all sensitivities. In addition, the costs of plans that substitute two smaller simple cycle combustion turbines or a larger combustion turbine like the GE 7EA are close enough in NPV cost, within less that one percent under base case conditions and within about one percent based on the average of the difference between the base case and each sensitivity, to warrant the inclusion of a range in turbine sizes in the solicitation of proposals to supply combustion turbines.

In addition, the following observations and conclusions, many the same as noted in the Observations and Conclusions Section of the Phase I analysis, can be summarized from the analyses in the previous sections of this report:

- BPU is projected to need 35 MW of additional generating capacity if Quindaro Unit 1 remains in service through 2017. If Quindaro Unit 1 is retired in 2011, BPU is projected to need 107 MW of additional generating capacity to meet its capacity responsibility over the next 10 years.
- Comparing the plans that continue Quindaro Unit 1 operation with the plans that do not, even with the addition of an SCR to Quindaro Unit 1, it is less costly to continue to operate Q1 through 2017 than to retire it in 2011. In addition to the $34 million SCR, the BPU could afford to spend an additional $37 million ($2008) on reliability maintenance projects before it would be less costly to its customers to retire the unit.
- Even a high carbon tax favors the continued operation of Q1. Under a high carbon tax scenario, the plans that retire Quindaro 1 in 2011 move ahead in the rankings to third and fourth, ahead of the plan that retains Quindaro 1 in service and adds a 7EA in 2011.
- Regardless of whether or not Q1 is retired early, the NPV costs of plans that add a Frame 7EA turbine, an LM6000 turbine, or LM2500 turbines in 2011 are so close as to indicate that BPU should solicit bids for these types of machines. Should later studies of the cost to keep Quindaro in service reveal that expenditures greater than $37 million are required and preclude its continued operation beyond 2011, the addition of either a simple cycle LM6000 or a simple cycle 7EA combustion turbine in 2011, followed by a

simple cycle 7EA in 2012 or a LM6000 in 2013, respectively, are not significantly different in NPV. Therefore, the decision to retire Quindaro 1 can be made after the decision on which simple cycle combustion turbine to procure as the next unit and the resulting impact on NPV cost will not vary significantly.

13.0 Revenues and Revenue Requirements

The Electric System provides retail service to residential, commercial, industrial, and other customers of the BPU and has contractual agreements for the wholesale sale of electricity. This section summarizes our forecast of Electric Utility revenue and revenue requirements of the BPU for the period 2008 through 2013. The forecasts reflect the BPU's proposed capital program including potential environmental upgrades to existing Nearman and Quindaro generating units and the addition of a new combustion turbine at Nearman (CT5), as recommended in the 10-Year Power Supply Plan. The forecasts reflect BPU plans as of September 1, 2008.

13.1 Sales Forecast

The basis of the sales forecast is the 2008 Load Forecast provided by BPU. The Load Forecast provides an annual forecast of sales in kilowatt-hours (kWh) by principal customer classes (Residential, Commercial, Industrial, etc.). As shown in Table 13-1, line 1, Total Retail sales are forecast to increase from nominally 2,320,000 kWh to 2,424,000 kWh for the period 2008 through 2013. This is approximately a 0.9 percent compound annual growth rate. Because our financial forecast requires sales to be classified into rate classes (Residential, Small General Service, Large General Service, etc.), it was necessary to reconcile the 2008 Load Forecast customer class sales to rate classes. We performed this transition using the 2007 rate class billing determinants and a report provided by BPU that records billing determinants by both customer class and rate class.

A monthly forecast of rate class billing determinants for 2008 through 2013 was developed by applying the percentage increases by rate class for sales and customer growth to the rate class monthly billing determinants for calendar year 2007. For rate classes billed based on kilowatt (kW) demand, demand growth was assumed to equal sales (kWh) growth.

13.2 Revenues Under Existing Rates

The base revenue forecast under existing rates was generated by applying the existing base rates per the Rate Application Manual dated December 20, 2006 to the rate class billing determinants. Revenue related to recovery of fuel and purchased power expenditures is calculated by applying the forecast of seasonal Energy Rate Component (ERC) to the rate class energy billing determinants. BPU developed the ERC Forecast in conjunction with the ProSym production cost modeling.

Table 13-1
Projected Revenues Under Existing Rates

Line	Description	Year					
		2008	2009	2010	2011	2012	2013
1	Retail Sales (MWh)	2,320,022	2,333,647	2,355,536	2,393,412	2,401,571	2,424,278
	REVENUES ($)						
2	**Base:**						
3	Retail Base Revenue	109,974,158	110,799,861	111,878,932	113,910,502	114,946,435	117,730,486
4	Wholesale Base Revenue						
5	Nearman Participants	6,830,098	7,591,992	8,735,629	9,248,972	9,473,981	13,709,450
6	Borderline	325,694	300,914	320,570	284,871	231,338	268,039
7	Off System Sales	2,251,407	2,107,697	1,558,703	2,019,355	2,230,422	2,561,190
8	Total Wholesale Base Revenue	9,407,199	10,000,603	10,614,901	11,553,199	11,935,740	16,538,679
9	**Total Base Revenue**	119,381,357	120,800,463	122,493,833	125,463,701	126,882,175	134,269,165
10	**Fuel:**						
11	Retail ERC Revenue	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
12	Nearman Participants Fuel Revenue	8,745,421	7,217,780	8,206,782	8,789,648	7,745,899	9,418,350
13	Borderline Fuel Revenue	487,279	520,189	508,744	552,736	614,645	586,404
14	Off System Sales Fuel Revenue	4,717,385	4,405,212	3,488,829	4,309,808	4,705,482	5,506,221
15	**Total Fuel Revenue**	77,554,555	82,263,879	83,365,217	93,253,104	100,098,419	100,246,945
16	Total Retail Rate Revenue	173,578,628	180,920,558	183,039,794	193,511,415	201,978,827	202,466,456
17	Total Wholesale Rate Revenue	23,357,284	22,143,784	22,819,257	25,205,390	25,001,767	32,049,654
18	**Total Rate Revenue**	**196,935,912**	**203,064,342**	**205,859,050**	**218,716,805**	**226,980,594**	**234,516,110**
19	**Other Revenue:**						
20	PILOT	15,185,264	15,694,071	15,987,247	16,938,153	17,559,734	18,091,781
21	Forfeited Discounts	2,100,000	2,142,000	2,184,800	2,228,500	2,273,100	2,318,600
22	Connect/Disconnect Fees	1,000,000	1,020,000	1,040,400	1,061,200	1,082,400	1,104,000
23	Tower/Pole Attachment Rentals	950,000	969,000	988,400	1,008,200	1,028,400	1,049,000
24	Ash Disposal	150,000	153,000	156,100	159,200	162,400	165,600
25	Diversion Fines	60,000	61,200	62,400	63,600	64,900	66,200
26	Service Fees	1,200,000	1,224,000	1,248,500	1,273,500	1,299,000	1,325,000
27	Other Miscellaneous Revenues	142,800	145,700	148,600	151,600	154,600	157,700
28	Rent From Electric Property	411,949	420,200	428,600	437,200	445,900	454,800
29	Margin on EIS Spot Market Sales	975,000	975,000	975,000	975,000	975,000	975,000
30	Investment Income	2,894,059	2,894,059	2,963,288	3,904,686	4,816,686	4,785,774
31	**Total Other Revenue**	**25,069,072**	**25,698,230**	**26,183,335**	**28,200,839**	**29,862,120**	**30,493,456**
32	**Total Revenue**	**222,004,983**	**228,762,572**	**232,042,385**	**246,917,644**	**256,842,714**	**265,009,565**

Retail revenues under existing rates reflect the two current sources of revenue: base rate revenue and ERC revenue, where base rates are the stated tariffs effective January 1, 2007. The forecast of the Electric System's operating revenues under existing rates are shown in Table 13-1. Line 3 shows the forecast of Retail base rate (non-fuel) sales revenue under existing rates and ranges from $110.0 million in 2008 to $117.7 million in 2013. Base rate sales revenue reflects the Retail kWh sales from the 2008 Load Forecast. Base rate sales revenue from wholesale customers is shown in lines 5 through 8 and increases from $9.4 million in 2008 to $16.5 million in 2013. The large increase in Nearman Participant sales in 2013 reflects the adjustment of participants' share of Nearman 1 AQC retrofits.

Charges related to fuel cost recovery are shown in lines 10 through 14. Retail sales fuel expenses are recovered through BPU's ERC rider. The ERC rider is adjusted semi-annually to recover forecast fuel expenditures and trued up for any revenue/cost variance in the prior like season period; summer for summer, winter for winter. For the purposes of this report, ERC revenue is set equal to retail fuel expense for the year.

The forecast of fuel expenses, wholesale sales, purchased power, and the calculation of ERC is forecast using the ProSym Production Cost Model. The model inputs reflect the addition of the recommended power supply plan and environmental upgrades. The hourly load inputs to the ProSym model are based on the same 2008 Load Forecast that is used to forecast sales. Fuel revenue on lines 11 through 14 are divided into ERC (retail) revenue, Nearman Participant fuel, Borderline fuel, and fuel for off-system sales. Nearman Participant, Borderline, and off-system energy sales are outputs of the ProSym model. From those energy sales, an estimate of the cost of fuel to produce wholesale sales is calculated. Total fuel revenue (line 15) ranges from $77.6 million in 2008 to $100.2 million in 2013 and matches fuel expense on Table 13-2, line 11.

Other revenues consist of Payments in Lieu of Taxes (PILOT) revenue; miscellaneous fees and rents such as Connect/Disconnect fees, Tower/Pole Attachment Rental, and Diversion Fines; margin on Energy Imbalance Service (EIS) spot market sales; and interest income. PILOT revenue (line 20) is calculated at the current rate of 7.9 percent of base rate and fuel charges (excluding off-system fuel). A proposed temporary increase in PILOT to 9.9 percent in 2009 and 2010 is not included in this analysis. PILOT is a pass-through revenue, and as such has no effect on the overall rate impact. Other revenue on lines 21 through 28 are based on the 2008 budget and escalated at 2 percent annually. Margin on EIS Spot Market Sales is based on BPU's estimate of $975,000 per year. Investment Income (line 30) is calculated on average balances for BPU's various funds using a 3.5 percent interest rate.

Table 13-2
Projected Revenue Requirements and Surplus/(Deficiency) Under Existing Rates

Line	Description	Year					
		2008	2009	2010	2011	2012	2013
	REVENUE REQUIREMENTS ($)						
1	**Fuel Expense**						
2	Retail						
3	Generation Fuel Costs	42,489,262	44,987,824	48,426,283	58,513,509	61,065,986	62,260,338
4	Purchased Power	21,115,208	25,132,874	22,734,578	21,087,404	25,966,406	22,475,632
5	Total Retail Fuel	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
6	Wholesale						
7	Borderline Fuel Costs	487,279	520,189	508,744	552,736	614,645	586,404
8	Nearman Participants Fuel Cost	8,745,421	7,217,780	8,206,782	8,789,648	7,745,899	9,418,350
9	Off System Fuel Costs	4,717,385	4,405,212	3,488,829	4,309,808	4,705,482	5,506,221
10	Total Wholesale Fuel	13,950,085	12,143,181	12,204,356	13,652,191	13,066,027	15,510,975
11	**Total Fuel Expense**	77,554,555	82,263,879	83,365,217	93,253,104	100,098,419	100,246,945
12	**Operation and Maintenance Expense**						
13	Production	34,667,235	36,696,605	36,500,609	37,053,756	38,592,997	38,720,763
14	Transmission	2,684,770	2,807,457	2,913,360	3,036,486	3,165,079	3,299,397
15	Distribution	19,192,856	20,059,030	20,915,854	21,811,446	22,747,669	23,726,483
16	Customer Accounts	5,238,725	5,472,997	5,709,314	5,956,498	6,215,080	6,485,620
17	Sales	719,400	753,472	784,851	817,585	851,735	887,365
18	Administrative and General	22,373,405	23,426,234	24,403,825	25,423,976	26,488,626	27,599,813
19	**Total O&M Expense**	84,876,391	89,215,795	91,227,813	94,099,745	98,061,186	100,719,442
20	**Total Expenses**	162,430,946	171,479,674	174,593,030	187,352,849	198,159,605	200,966,387
21	**Net Revenues**	59,574,038	57,282,899	57,449,355	59,564,795	58,683,109	64,043,178
22	**Debt Service**						
23	Existing Debt Service	24,003,296	20,414,676	20,373,119	19,785,713	19,782,953	19,796,067
24	2008 Bonds ($54.9 million)	-	3,789,732	3,717,269	3,726,762	3,744,474	3,746,927
25	2009 Environmental Bonds ($118.9 million)	-	3,566,520	9,809,373	9,809,373	9,809,373	9,809,373
26	2009 Capital Bonds ($92.9 million)	-	2,862,240	7,463,455	7,463,455	7,463,455	7,463,455
27	2011 Environmental Bonds ($134.9 million)		-	-	4,047,630	10,554,427	10,554,427
28	2011 Capital Bonds ($61.2 million)	-	-	-	1,744,890	4,549,901	4,549,901
29	**Total Debt Service**	24,003,296	30,633,168	41,363,216	46,577,823	55,904,583	55,920,150
30	Revenue After Debt Service Obligation	35,570,741	26,649,731	16,086,140	12,986,972	2,778,526	8,123,028
31	**Debt Service Coverage Under Existing Rates**						
32	Total System Achieved	**2.48**	**1.87**	**1.39**	**1.28**	**1.05**	**1.15**
33	Minimum Coverage Required	1.60	1.60	1.60	1.60	1.60	1.60
34	**Other Expenditures and Transfers**						
35	PILOT	15,185,264	15,694,071	15,987,247	16,938,153	17,559,734	18,091,781
36	Cash Financed Capital Projects	18,250,540	13,192,247	14,970,219	17,121,906	19,360,325	26,640,541
37	Less: Reimbursable Projects	(428,200)	(208,200)	(208,200)	(208,200)	(208,200)	(208,200)
38	Capital Lease Payments	1,103,401	187,671	-	-	-	-
39	Heat Pump Program	558,642	850,000	850,000	850,000	850,000	850,000
40	Economic Development Fund Authorization	525,000	525,000	525,000	525,000	525,000	525,000
41	**Total Other Exp. And Transfers**	**35,194,647**	**30,240,789**	**32,124,266**	**35,226,859**	**38,086,859**	**45,899,122**
42	**Total Revenue Requirement**	221,628,889	232,353,630	248,080,512	269,157,531	292,151,047	302,785,659
43	**Net Revenue Requirement**	196,559,817	206,655,401	221,897,177	240,956,692	262,288,927	272,292,203
44	Revenue Surplus / (Deficiency) Under Existing	376,095	(3,591,058)	(16,038,126)	(22,239,887)	(35,308,333)	(37,776,094)

Total revenue under existing rates and other sources, shown on line 32, is forecast to increase from $222.0 million in 2008 to $265.0 million in 2013.

13.3 Revenue Requirements

The overall adequacy of the existing rates is tested by comparing revenues under existing rates with revenue requirements. Revenue requirements are developed on a cash basis and consist primarily of fuel expenditures, operation and maintenance (O&M) expenses, debt service requirements, cash financed capital projects, PILOT, and other miscellaneous program costs such as the heat pump program. The forecast of annual revenue requirements is shown in Table 13-2 and discussed in the following sections.

13.3.1 Fuel Expenses

As discussed in Section 13.2, the forecast of fuel expenses is based on the ProSym production cost model of the recommended power supply plan. The forecast provides a monthly forecast of generation for each generating unit, fuel costs for each unit, purchased power fuel cost and related production expenses. The forecast of fuel expenses is summarized on lines 1 through 11 of Table 13-2.

13.3.2 Operation and Maintenance Expense

The forecast of operation and maintenance (O&M) expense is based on the 2008 Budget. The 2008 Budget is categorized by FERC account, with additional detail for Dept ID and Class ID. The forecast of O&M expenses for 2009 through 2013 categorized each budget item as Direct Labor, Labor Burden/Benefits, and Non-Labor Expenses. Direct Labor is forecast to increase at 3.5 percent per year. Labor Burden and Benefits are forecast to increase 6 percent annually. Non-Labor Expenses are forecast to increase 5 percent in 2009 and 4 percent for the remaining years in the study period. The 2009 percentage is higher to account for an expected increase in use of contract labor. BPU reviewed the non-fuel production O&M forecast and made adjustments to reflect expected operations under the recommended power supply plan. O&M expenses are summarized on lines 12 through 19 of Table 13-2.

13.3.3 Capital Improvement Plan

The baseline Capital Improvement Plan (CIP) is the 2008 Budget, which provides a five-year (2008 through 2012) capital plan and projection of funding sources. The production budget plan was modified by BPU to incorporate needed equipment replacements for existing units to accommodate the recommended power supply plan including the following capacity addition and environmental projects:

- Construction of a combustion turbine generator at Nearman (CT5) by 2011.
- Low NO_x Burners (LNB) and Over Fire Air (OFA) at Nearman 1 and Quindaro 2 units, with construction completed by 2010.
- Flue Gas Desulfurization (FGD), Fabric Filter, and Landfill improvements at Nearman 1, with construction completed by December 2012.
- Selective Catalytic Reduction (SCR) at Quindaro 1 with construction completed by 2012.

The 2013 CIP was based on the trend of prior years' budgeted projects for routine replacements. Table 13-3 presents the adjusted CIP through 2013.

13.3.4 Debt Service

BPU's Capital Improvement Plan will be financed with a blend of long-term debt (bonds) and cash financing from operating revenues. The CIP projects in Table 13-3 are divided into two groups: environmental projects and all other capital projects. The environmental projects are maintained separately, as we recommend financing these exclusively from a proposed Environmental Surcharge (see Subsection 13.4.1).

The environmental projects are scheduled to be constructed from 2009 through 2012 and total $248.7 million. For purposes of the financial forecast, we assume the projects will be financed with three bond issues. Two bonds will be issued in 2009; one for the first two years of Nearman environmental projects ($62.0 million) and one for Quindaro environmental projects ($56.9 million). For forecast purposes the 2009 bonds are separated into Quindaro projects financed over 20 years (due to the current age and expected remaining life of Quindaro) and all other debt financed projects are financed over 25 years. The remaining Nearman environmental projects will be financed with a $132.9 million issue in 2011. All bond amounts and debt service payments are estimated at 6.0 percent (which was a more recent estimate of interest than what was used in the Phase I and II analyses) interest and 2.0 percent issuance costs. Annual debt service payments for existing and proposed bonds are shown on lines 23 through 28 of Table 13-2. Total debt service increases from $24.0 million in 2008 to $55.9 million in 2013.

Table 13-3
Capital Improvement Plan (2008 through 2013)

Line	Description	Year 2008	2009	2010	2011	2012	2013	Total
	Electric System Capital Projects							
1	Electric Unit Equipment	$ 48,138	$ 901,500	$ 922,000	$ 1,123,000	$ 1,217,000	$ 1,170,000	$ 5,381,638
2	Electric Ops General Construction	682,435	860,000	820,000	720,000	620,000	670,000	4,372,435
3	Electric Supply General Construction	75,000						75,000
4	Electric Accident Claims	108,200	108,200	108,200	108,200	108,200	108,200	649,200
5	Electric Overhead Distribution	3,559,848	4,200,000	5,524,561	6,584,506	2,800,000	4,692,253	27,361,168
6	Electric UG Distribution	1,956,796	2,750,000	4,500,000	4,000,000	3,500,000	3,750,000	20,456,796
7	Electric Reimbursible	100,000	100,000	100,000	100,000	100,000	100,000	600,000
8	Electric Transmission	8,083,000	2,481,500	9,650,000	8,150,000	650,000	4,400,000	33,414,500
9	Electric Transformers	820,000	900,000	900,000	900,000	900,000	900,000	5,320,000
10	Electric Meters	350,000	1,000,000	2,000,000	2,000,000	2,000,000	2,000,000	9,350,000
11	Electric Lighting & Signals	480,715	500,000	600,000	600,000	500,000	550,000	3,230,715
12	Electric Substations	7,431,731	9,620,037	8,550,000	1,800,000	1,800,000	1,800,000	31,001,768
13	Storm Expenses	1,000	1,000	1,000	1,000	1,000	1,000	6,000
14	Nearman Unit 1	2,998,089	2,457,657	2,834,000	3,304,000	16,576,000	532,000	28,701,746
15	Nearman Common	1,475,894	2,134,000	1,714,000	134,000	594,000	3,662,000	9,713,894
16	Nearman CT5		14,736,800	51,578,800	7,368,400			73,684,000
17	Quindaro Unit 1	834,443	168,000	3,192,000	15,400,000	392,000	784,000	20,770,443
18	Quindaro Unit 2	9,159,183	2,339,557	560,000	1,120,000	616,000	2,072,000	15,866,740
19	Quindaro Common	2,288,016	2,817,000	1,070,000	588,000	700,000	2,296,000	9,759,016
20	Quindaro CT1	-	1,120,000	258,000	-	-	-	1,378,000
21	Quindaro CT2	-	-	1,613,000	-	-	-	1,613,000
22	Quindaro CT3	-	-	2,565,000	-	112,000	-	2,677,000
23	Electric Control Center	425,000	500,000	250,000	-	-	-	1,175,000
24	**Total Electric Capital Projects**	**$ 40,877,488**	**$ 49,695,251**	**$ 99,310,561**	**$ 54,001,106**	**$ 33,186,200**	**$ 29,487,453**	**$ 306,558,059**
25	**Environmental/AQC Projects**							
26	N1 LNB & OFA - $23,476,000 (2010$)		21,128,400	2,347,600				23,476,000
27	Q2 LNB & OFA - $12,203,000 (2010$)		10,982,700	1,220,300				12,203,000
28	N1 FGD, FF, & Landfill - $169,516,000 (2012$)		3,390,320	33,903,200	101,709,600	30,512,880		169,516,000
29	Q1 SCR - $43,534,000 (2011$)		8,706,800	15,236,900	15,236,900	4,353,400		43,534,000
30	**Total Environmental/AQC Projects**	**$ -**	**$ 44,208,220**	**$ 52,708,000**	**$ 116,946,500**	**$ 34,866,280**	**$ -**	**$ 248,729,000**
31	Common Furnish and Equipment	5,000	20,000	25,000	25,000	25,000	25,000	125,000
32	Common Facility Improvements	100,873	546,308	261,210	217,400	225,500	221,450	1,572,741
33	Common Grounds	-	10,000	10,000	10,000	10,000	10,000	50,000
34	Common Technology	1,341,263	827,000	815,000	802,000	860,000	831,000	5,476,263
35	Administrative Service Technology	383,600	430,000	435,000	440,000	445,000	450,000	2,583,600
36	**Total Common Projets**	**$ 1,830,736**	**$ 1,833,308**	**$ 1,546,210**	**$ 1,494,400**	**$ 1,565,500**	**$ 1,537,450**	**$ 9,807,604**
37	**Electric Portion of Common Projects @ 75%**	**1,373,052**	**1,374,981**	**1,159,658**	**1,120,800**	**1,174,125**	**1,153,088**	**7,355,703**
38	**Environmental/AQC Projects**							
39	Nearman	-	24,518,720	36,250,800	101,709,600	30,512,880	-	
40	Quindaro	-	19,689,500	16,457,200	15,236,900	4,353,400	-	
		-	44,208,220	52,708,000	116,946,500	34,866,280	-	
41	**Financing Recap**							
42	2008 Debt Issue (Capital)	24,000,000	29,877,985					53,877,985
43	2009 Nearman Environmental		24,518,720	36,250,800				60,769,520
44	2009 Quindaro Environmental		19,689,500	16,457,200	15,236,900	4,353,400		55,737,000
45	2011 Nearman Environmental				101,709,600	30,512,880		132,222,480
46	2009 Capital		8,000,000	85,500,000				93,500,000
47	2011 Capital				38,000,000	15,000,000	4,000,000	57,000,000
48	**Net Amount to Cash Finance**	**18,250,540**	**13,192,247**	**14,970,219**	**17,121,906**	**19,360,325**	**26,640,541**	**109,535,777**

Note: All dollar amounts are shown in real dollars unless otherwise noted.

The remaining capital projects in the CIP, including the construction of CT5 at Nearman, will be financed primarily with proceeds from bond issues in 2008, 2009, and 2011. The currently budgeted Series 2008 Bonds are forecast to provide proceeds of $53.9 million for needed routine replacements. The bond amounts for the 2009 and 2011 series bonds are projected to cover the remaining projects in the CIP, less an amount of annual cash financed capital projects. The $73.7 million in financing for the addition of CT5 is included in the 2009 and 2011 capital bonds. The amount of cash financing (shown on Table 13-3, line 48) varies based on the cash flow capability of BPU and ranges from a low of $13.2 million in 2009 to $26.6 million in 2013. The recent average rate for BPU cash financed projects has been in the $15 to 20 million range. Following the series of base rate increases we recommend, we anticipate BPU can increase the average amount of cash financed projects to approximately $25 million annually.

13.3.5 Other Expenditures and Transfers

Other expenditures, on Table 13-2, lines 37 through 40, include capital lease payments and costs associated with the Heat Pump Program and Economic Development Fund Authorization. Revenue from reimbursable projects is shown as negative and reduces the overall revenue requirement. Payment in lieu of taxes (PILOT) shown on line 35 is the transfer of PILOT funds collected to the Unified Government (UG). The amount of the transfer is equal to the funds collected and as such has no net impact on the revenue requirement. Total Expenditures and Transfers (including cash financed capital projects) shown on line 41 of Table 13-2 ranges from $30.2 million in 2009 to $45.9 million in 2013.

13.3.6 Total Revenue Requirement and Revenue Deficiency

The total revenue requirement of the Electric Utility is the sum of fuel expense, O&M expense, debt service payments, and other expenditures and transfers. As shown on line 42 of Table 13-2, the total revenue requirement is forecast to increase from $221.6 million in 2008 to $302.8 million in 2013. The annual revenue surplus or deficiency is calculated by subtracting this amount from the total revenue under existing rates on line 32 of Table 13-1. The annual surplus/deficiency ranges from a surplus of $0.4 million in 2008, and deficiencies of $3.6 million in 2009, increasing to a deficiency of $37.8 million in 2013.

13.3.7 Debt Service Coverage Under Existing Rates

The stated BPU financial policy regarding debt service coverage states that the BPU maintain minimum debt service coverage such that net revenues are 1.6 times the maximum annual debt service. On line 32 of Table 13-2 is the forecast of debt service coverage under existing rates. Based on the forecast, BPU's debt service coverage under existing rates is below 1.6 in every year from 2010 through 2013.

13.4 Proposed Adjustment to Rates

The total revenue deficiency under existing rates for 2009 through 2013 is projected to be approximately $115 million. To address the significant annual deficiencies we recommend an Environmental Surcharge (ESC) to recover the capital portion of environmental upgrades discussed in Subsection 13.3.3, and a series of consecutive annual base rate increases from 2010 through 2012.

13.4.1 Environmental Surcharge

In order to tie the recovery of capital costs related to required environmental projects we recommend the ESC be implemented beginning in January 2009. The surcharge would be a new rate rider applied on a uniform $/kWh basis to all revenue generating Retail rate classes. The ESC would be designed to recover the annual debt service payment on existing unit's environmental upgrades. The ESC would be adjusted annually to recover upcoming year's debt service payment on the 2009 Nearman, 2009 Quindaro, and 2011 Nearman environmental bonds. The total amount to be recovered from retail ratepayers will be reduced by the required pro-rata contribution of the Nearman Participants.

The projected ESC is $0.0015/kWh in 2009, $0.0040/kWh in 2010, $0.0056/kWh in 2011, $0.0083/kWh in 2012, and $0.0067/kWh in 2013. Revenues generated by the ESC are forecast to increase from $3.6 million in 2009 to $19.9 million in 2012, and $16.3 million in 2013.

13.4.2 Adjustment to Retail Base Rates

The remaining revenue deficiency will need to be recovered through increases to retail base rates. The rate adjustments must be sufficient to meet BPU's stated financial policies for debt service coverage and operating reserve levels. BPU's stated financial policy requires a minimum debt service coverage ratio of 1.60 (net revenues available for debt service must be 1.6 times the annual debt service payment). In addition, BPU has stated financial policies for operating cash reserves and Rate Stabilization Fund balances.

Currently, the fund balances for operating reserve and Rate Stabilization are approximately $10 million underfunded relative to financial policy. To meet BPU financial objectives, address the revenue deficiencies, and lessen the rate impact on retail customers, we recommend a series of annual retail base rate increases of 6.25 percent from 2010 through 2012.

13.5 Revenue and Revenue Requirements Under Proposed Rates

Table 13-4 presents the financial operations of the Electric System under the proposed retail base rate revenue increases and the ESC. Revenue requirements under proposed rates are the same as under existing rates with the exception of PILOT, which is larger because it is calculated on higher revenues. Because PILOT revenue is included in the calculation of debt service coverage, this has the impact of further improving debt service coverage. Debt service coverage in the years following rate adjustment ranges from 1.81 to 2.00.

Total annual revenue surplus or deficiency is shown on line 78 of Table 13-4. The surpluses shown in 2011 and 2012 are used to bring BPU in compliance with its stated financial policies. As shown on line 84, BPU is forecast to be deficient in meeting its financial policies of operating reserve and rate stabilization until 2012.

13.6 Overall Projected Rate Impact

The overall rate impact of the rate proposals is shown in Table 13-5. The average sales rate (in $/kWh) under existing rates (line 6) is calculated by dividing existing revenue (line 5) by Retail sales (line 1) and dividing by 1,000. Projected revenue under proposed rates shown on line 10 is the sum of retail revenue under existing rates (line 5), ESC revenue (line 7), and revenue from proposed base rate increases (line 8). The projected average sales rate is shown on line 11 and increases from an existing $0.0748/kWh in 2008, peaks at $0.1014/kWh in 2012 and declines to $0.0993/kWh in 2013. Year-over-year overall percentage rate increases are shown on line 12. The projected cumulative rate increase for the period 2008 through 2013 is 32.8 percent.

Figure 13-1 presents the projected $/kWh increase by rate components for: existing base, ERC, ESC and projected base rate increases for each of the six years. As shown in the stacked bar chart increases in ERC and the ESC are responsible for over half of the projected increase in rates. Both of these rate components are driven by external factors outside the direct control of the BPU. ERC is driven by the cost of fuels (coal and natural gas) and power market purchases. ESC reflects the projected rate impact of environmental capital expenditures that may be required by state or Federal regulations. Figure 13-2 presents a chart of the projected cumulative percent increase of 32.8 percent by rate component. ERC and ESC account for approximately 58 percent of the overall projected increase. Base rate increases account for the remaining 42 percent of the overall increase and are driven primarily by projected increases in operating and capital expenditures, the need to increase cash reserves to meet financial policy, and debt service on the proposed CT 5. We estimate approximately half of the base rate increase is attributable to CT5. However, without CT5 BPU would need to purchase replacement power off system at potentially higher and more volatile market prices increasing the projected ERC charges and increasing the risk of power delivery unavailability due to external transmission constraints.

Table 13-4
Projected Revenue and Revenue Requirements Under Proposed Rates
Page 1 of 2

Line	Description	Year 2008	2009	2010	2011	2012	2013
1	Retail Sales (MWh)	2,320,022	2,333,647	2,355,536	2,393,412	2,401,571	2,424,278
	REVENUES ($)						
2	**Base:**						
3	Retail Base Revenue Existing Rates	109,974,158	110,799,861	111,878,932	113,910,502	114,946,435	117,730,486
4	Proposed Base Rate Revenue Increases			6,992,433	14,238,813	21,552,457	22,074,466
5	Wholesale Base Revenue						
6	Nearman Participants	6,830,098	7,591,992	8,735,629	9,248,972	9,473,981	13,709,450
7	Borderline	325,694	300,914	320,570	284,871	231,338	268,039
8	Off System Sales	2,251,407	2,107,697	1,558,703	2,019,355	2,230,422	2,561,190
9	Total Wholesale Base Revenue	9,407,199	10,000,603	10,614,901	11,553,199	11,935,740	16,538,679
10	**Total Base Revenue**	119,381,357	120,800,463	129,486,267	139,702,514	148,434,632	156,343,631
11	**Fuel:**						
12	Retail ERC Revenue	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
13	Nearman Participants Fuel Revenue	8,745,421	7,217,780	8,206,782	8,789,648	7,745,899	9,418,350
14	Borderline Fuel Revenue	487,279	520,189	508,744	552,736	614,645	586,404
15	Off System Sales Fuel Revenue	4,717,385	4,405,212	3,488,829	4,309,808	4,705,482	5,506,221
16	**Total Fuel Revenue**	77,554,555	82,263,879	83,365,217	93,253,104	100,098,419	100,246,945
17	Environmental Surcharge Revenue		3,566,520	9,314,193	13,361,823	19,868,620	16,293,076
18	Total Retail Rate Revenue	173,578,628	184,487,078	199,346,420	221,112,051	243,399,904	240,833,998
19	Total Wholesale Rate Revenue	23,357,284	22,143,784	22,819,257	25,205,390	25,001,767	32,049,654
20	**Total Rate Revenue**	**196,935,912**	**206,630,862**	**222,165,677**	**246,317,441**	**268,401,671**	**272,883,652**
21	**Other Revenue:**						
22	PILOT	15,185,264	15,975,826	17,275,471	19,118,603	20,831,999	21,122,817
23	Forfeited Discounts	2,100,000	2,142,000	2,184,800	2,228,500	2,273,100	2,318,600
24	Connect/Disconnect Fees	1,000,000	1,020,000	1,040,400	1,061,200	1,082,400	1,104,000
25	Tower/Pole Attachment Rentals	950,000	969,000	988,400	1,008,200	1,028,400	1,049,000
26	Ash Disposal	150,000	153,000	156,100	159,200	162,400	165,600
27	Diversion Fines	60,000	61,200	62,400	63,600	64,900	66,200
28	Service Fees	1,200,000	1,224,000	1,248,500	1,273,500	1,299,000	1,325,000
29	Other Miscellaneous Revenues	142,800	145,700	148,600	151,600	154,600	157,700
30	Rent From Electric Property	411,949	420,200	428,600	437,200	445,900	454,800
31	Margin on EIS Spot Market Sales	975,000	975,000	975,000	975,000	975,000	975,000
32	Investment Income	2,894,059	2,894,059	2,963,288	3,904,686	4,816,686	4,785,774
33	**Total Other Revenue**	**25,069,072**	**25,979,985**	**27,471,559**	**30,381,289**	**33,134,385**	**33,524,491**
34	**Total Revenue**	**222,004,983**	**232,610,847**	**249,637,236**	**276,698,730**	**301,536,056**	**306,408,143**

Table 13-4 (Continued)
Projected Revenue and Revenue Requirements Under Proposed Rates
Page 2 of 2

Line	Description	Year 2008	2009	2010	2011	2012	2013
35	**REVENUE REQUIREMENTS ($)**						
36	**Fuel Expense**						
37	Retail						
38	Generation Fuel Costs	42,489,262	44,987,824	48,426,283	58,513,509	61,065,986	62,260,338
39	Purchased Power	21,115,208	25,132,874	22,734,578	21,087,404	25,966,406	22,475,632
40	Total Retail Fuel	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
41	Wholesale						
42	Borderline Fuel Costs	487,279	520,189	508,744	552,736	614,645	586,404
43	Nearman Participants Fuel Cost	8,745,421	7,217,780	8,206,782	8,789,648	7,745,899	9,418,350
44	Off System Fuel Costs	4,717,385	4,405,212	3,488,829	4,309,808	4,705,482	5,506,221
45	Total Wholesale Fuel	13,950,085	12,143,181	12,204,356	13,652,191	13,066,027	15,510,975
46	**Total Fuel Expense**	77,554,555	82,263,879	83,365,217	93,253,104	100,098,419	100,246,945
47	**Operation and Maintenance Expense**						
48	Production	34,667,235	36,696,605	36,500,609	37,053,756	38,592,997	38,720,763
49	Transmission	2,684,770	2,807,457	2,913,360	3,036,486	3,165,079	3,299,397
50	Distribution	19,192,856	20,059,030	20,915,854	21,811,446	22,747,669	23,726,483
51	Customer Accounts	5,238,725	5,472,997	5,709,314	5,956,498	6,215,080	6,485,620
52	Sales	719,400	753,472	784,851	817,585	851,735	887,365
53	Administrative and General	22,373,405	23,426,234	24,403,825	25,423,976	26,488,626	27,599,813
54	**Total O&M Expense**	84,876,391	89,215,795	91,227,813	94,099,745	98,061,186	100,719,442
55	**Total Expenses**	162,430,946	171,479,674	174,593,030	187,352,849	198,159,605	200,966,387
56	**Net Revenues**	59,574,038	61,131,174	75,044,206	89,345,881	103,376,451	105,441,756
57	**Debt Service**						
58	Existing Debt Service	24,003,296	20,414,676	20,373,119	19,785,713	19,782,953	19,796,067
59	2008 Bonds ($54.9 million)	-	3,789,732	3,717,269	3,726,762	3,744,474	3,746,927
60	2009 Environmental Bonds ($118.9 million)	-	3,566,520	9,809,373	9,809,373	9,809,373	9,809,373
61	2009 Capital Bonds ($92.9 million)	-	2,862,240	7,463,455	7,463,455	7,463,455	7,463,455
62	2011 Environmental Bonds ($134.9 million)	-	-	-	4,047,630	10,554,427	10,554,427
63	2011 Capital Bonds ($61.2 million)	-	-	-	1,744,890	4,549,901	4,549,901
64	**Total Debt Service**	24,003,296	30,633,168	41,363,216	46,577,823	55,904,583	55,920,150
65	Revenue After Debt Service Obligation	35,570,741	30,498,006	33,680,990	42,768,058	47,471,868	49,521,606
66	**Debt Service Coverage Under Proposed Rates**						
67	Total System Achieved	**2.48**	**2.00**	**1.81**	**1.92**	**1.85**	**1.89**
68	Minimum Coverage Required	1.60	1.60	1.60	1.60	1.60	1.60
69	**Other Expenditures and Transfers**						
70	PILOT	15,185,264	15,975,826	17,275,471	19,118,603	20,831,999	21,122,817
71	Cash Financed Capital Projects	18,250,540	13,192,247	14,970,219	17,121,906	19,360,325	26,640,541
72	Less: Reimbursable Projects	(428,200)	(208,200)	(208,200)	(208,200)	(208,200)	(208,200)
73	Capital Lease Payments	1,103,401	187,671	-	-	-	-
74	Heat Pump Program	558,642	850,000	850,000	850,000	850,000	850,000
75	Economic Development Fund Authorization	525,000	525,000	525,000	525,000	525,000	525,000
76	**Total Other Exp. And Transfers**	**35,194,647**	**30,522,544**	**33,412,489**	**37,407,309**	**41,359,124**	**48,930,158**
77	**Total Revenue Requirement**	221,628,889	232,635,386	249,368,735	271,337,981	295,423,312	305,816,695
78	Revenue Surplus / (Deficiency) Under Proposed Rates	376,095	(24,538)	268,501	5,360,749	6,112,744	591,449
79	**Operating Cash Balance**						
80	Beg Balance	10,826,298	11,202,393	11,177,854	11,446,355	16,807,104	22,919,848
81	Annual Cash Flow	376,095	(24,538)	268,501	5,360,749	6,112,744	591,449
82	End Balance	11,202,393	11,177,854	11,446,355	16,807,104	22,919,848	23,511,297
83	Target Operating Balance to Meet Financial Policies		20,781,025	20,807,824	21,358,219	22,749,815	23,300,825
84	Target Cash (Deficiency)/Surplus		(9,603,171)	(9,361,469)	(4,551,115)	170,033	210,472

Table 13-5
Overall Retail Rate Impact of Proposed Rates

Line	Description	For the Fiscal Year Ended: 2008	2009	2010	2011	2012	2013
		$	$	$	$	$	$
1	Forecast Retail Sales (MWh)	2,320,022	2,333,647	2,355,536	2,393,412	2,401,571	2,424,278
2	Retail Revenue Under Existing Rates						
3	Base Rates	109,974,158	110,799,861	111,878,932	113,910,502	114,946,435	117,730,486
4	ERC Revenue	63,604,470	70,120,698	71,160,861	79,600,913	87,032,392	84,735,970
5	Total Retail Rate Revenue	173,578,628	180,920,558	183,039,794	193,511,415	201,978,827	202,466,456
6	Average Sales Rate Under Existing Rates ($/kWh)	0.0748	0.0775	0.0777	0.0809	0.0841	0.0835
7	ESC Revenue		3,566,520	9,314,193	13,361,823	19,868,620	16,293,076
8	Proposed Base Rate Increases		-	6,992,433	14,238,813	21,552,457	22,074,466
9	Overall Rate Increases		3,566,520	16,306,627	27,600,636	41,421,077	38,367,542
10	Total Proposed Retail Rate Revenue	173,578,628	184,487,078	199,346,420	221,112,051	243,399,904	240,833,998
11	Average Sales Rate Under Proposed Rates ($/kWh)	0.0748	0.0791	0.0846	0.0924	0.1014	0.0993
12	Annual Percentage Increase Over Existing Rates (1)		5.5%	7.2%	9.6%	10.7%	-2.4%

Notes:
(1) Calculated as current year proposed rate minus previous year proposed rate, divided by current year existing rate
Example: 2010 % Increase = (.0846 - .0791) / .0777 = 7.2%

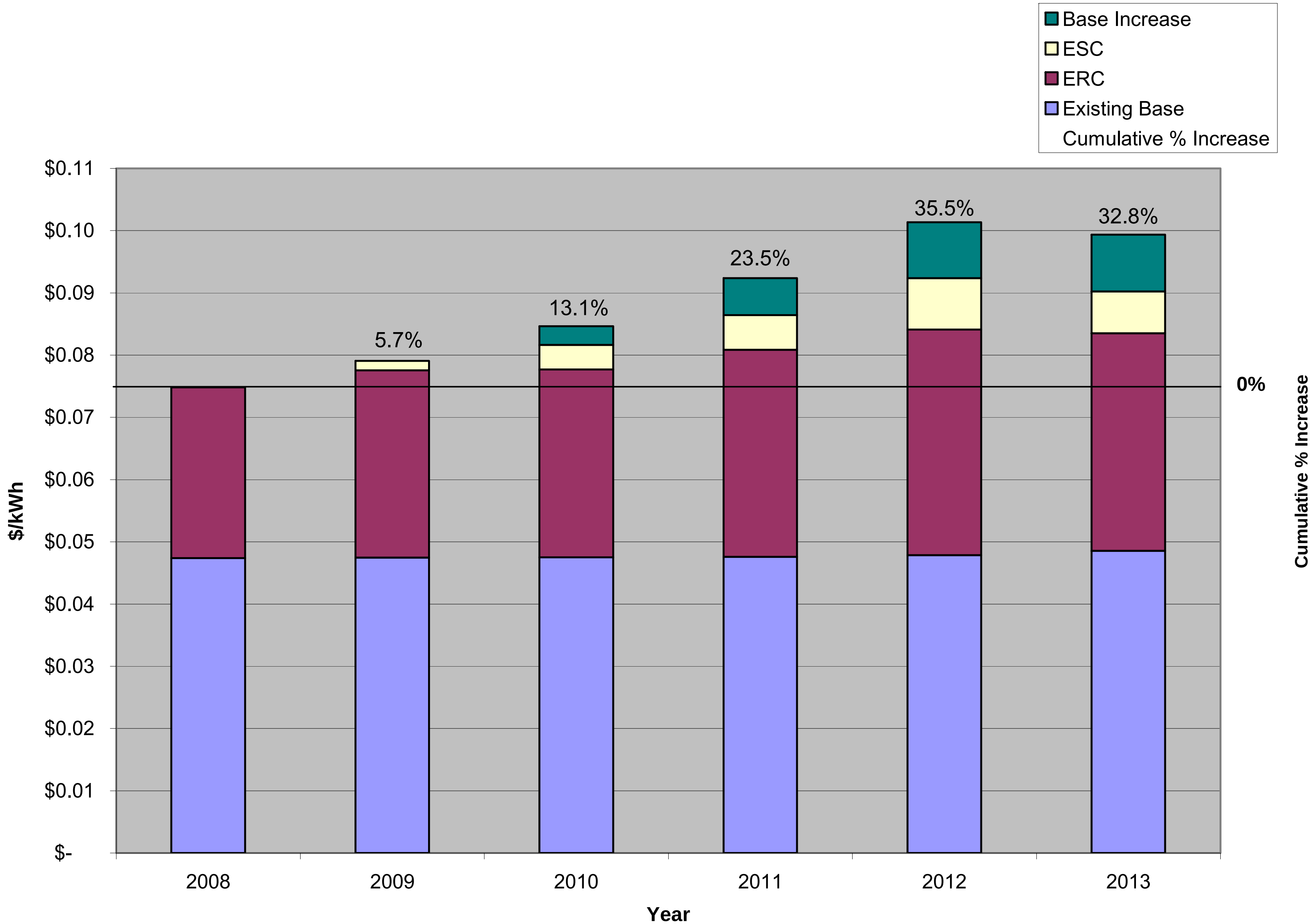


Figure 13-1
Total Projected Rates and Cumulative Percentage Increase

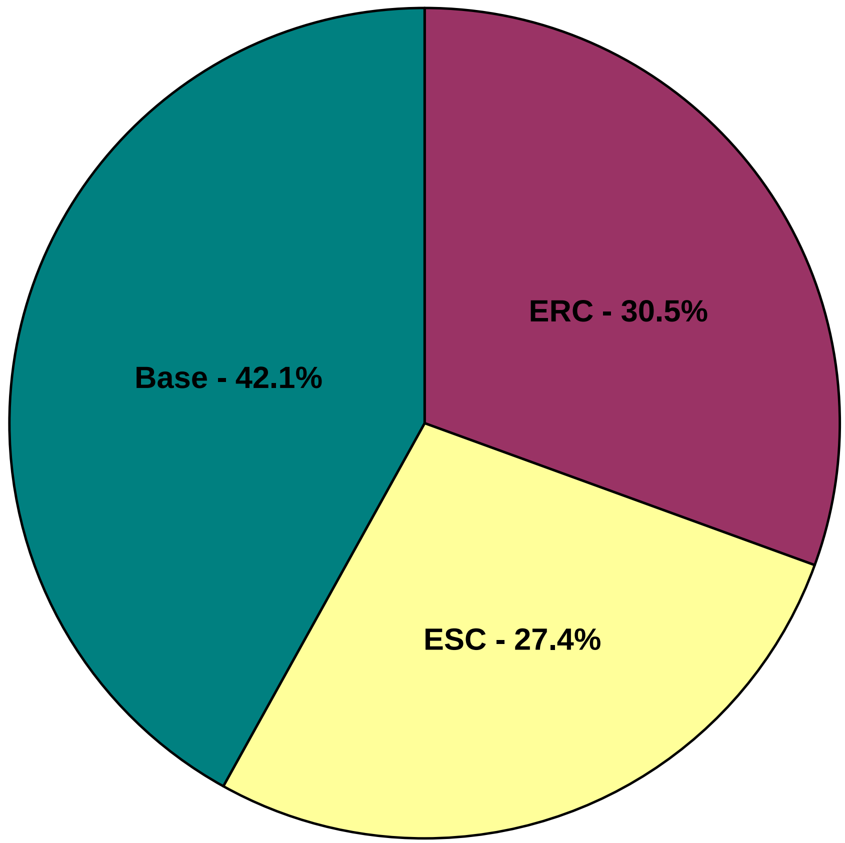


Figure 13-2
Percent of Total 32.8 Percent Increase - 2008 through 2013 - by Rate Component

14.0 Site Selection Introduction

In 2008, the Kansas City BPU retained Black & Veatch to provide services related to conducting a 10 Year Power Supply Study. This included an in-depth analysis of future power supply requirements based upon installation of simple cycle units or combined cycle unit using natural gas as the primary fuel. The purpose of the study was to determine the most economical installation of units to provide the future power requirements of BPU customers.

While BPU and Black & Veatch conducted a review of BPU's future power supply requirements, existing resources, and potential generation additions, Black & Veatch also performed a site selection study to determine the best location for installation of a simple cycle unit or a combined cycle unit.

Criteria were developed to provide adequate information to assess site and resource requirements. The criteria were based on an installation of a simple cycle combustion turbine units in the 20 to 75 MW size range or a combined cycle unit in the 110 to 120 MW range at the selected facility.

This site selection study is based on installing a simple cycle unit or combined cycle unit. Only existing BPU power plants and existing or planned future substation sites within Wyandotte County were identified as the sites for study.

This report documents the procedures and results of the siting study. Evaluation criteria and scoring factors were developed to evaluate the suitability of the identified sites to support the proposed facility. This evaluation was accomplished by first establishing technical parameters. Potential sites were identified and a screening process was then used to identify candidate sites that satisfied the technical requirements. The remaining candidate sites were evaluated using a criteria/scoring system developed specifically for the project. The principal results of the study are the scoring analysis and the identification of preferred and alternate sites.

14.1 Study Approach

Identification of the potential sites was accomplished using the following main tasks:

- Study Area Definition.
- Development of Siting Evaluation Criteria.
- Identification of Potential Sites.
- Initial Screening of Potential Sites.
- Remaining Potential Site Evaluation.
- Identification of Candidate Sites.

- Application of Site Evaluation Criteria.
- Establishment of Site Rankings.
- Identification of Preferred and Alternate Sites.

Black & Veatch used Map Quest to obtain aerial views of the potential sites. A map indicating the existing and planned transmission lines and existing major natural gas supply pipelines locations was provided by BPU to initially assess the sites. The Map Quest aerial views were used to identify the geographical locations and physical attributes of the sites including land availability and closeness of adjacent property owners to determine if the sites were adequate for generation development.

Working closely with BPU personnel, transmission interconnection issues were identified that would further refine the suitability of a potential siting area as a location for a candidate site. Initially, potential sites were defined as the BPU's existing three power plant sites and the 26 existing or future planned substation sites. All potential sites were initially screened and all sites which did not have, or have future planned, 161 kV transmission access or were further than 1 mile from existing adequate natural gas supplies were eliminated. The potential sites then were further evaluated, including some site reconnaissance to determine socioeconomic impacts, land use, and site development issues. The potential sites were further reduced based on this evaluation and the remaining sites were considered candidate sites. The suitability of each candidate site was evaluated using established criteria. Each of the candidate sites was rated and ranked in relation to each other, using a scoring system developed cooperatively by BPU and Black & Veatch personnel. The various evaluation criteria used during the study, as well as the overall site selection methodology, are presented in the following sections of this report. The report also includes a description of the entire site selection process, from the definition of the study area through the overall ranking of the sites and the selection of the preferred and alternate sites.

15.0 Project Description

BPU, working with Black & Veatch, is providing this site selection study to support development of a 10 year combustion turbine based power supply study. The purpose of this study is to determine candidate electrical generating sites for a simple cycle unit or a combined cycle unit. To that end, site selection and rankings were needed to assist in determining the feasibility of the generation sites.

A summary project description of the combustion turbine technology considered is provided herein. The following subsections provide conceptual design information developed to assess site selection and licensing requirements.

15.1 Proposed Project

This section briefly describes the basic requirements of a simple cycle unit and combined cycle unit and identifies the major features of these units.

15.1.1 Facility Size

Simple cycle units of the 20 to 75 MW size and combined cycle units in the 110 to 120 MW size were selected for the siting study. Each of the units was assumed to incorporate Best Available Control Technology (BACT) air quality controls, as appropriate and as required by permitting agencies. Simple cycle units would be installed without SCR or CO catalysts with natural gas as the primary fuel and Number 2 ultra low sulfur fuel oil as backup fuel. Combined cycle units would include a SCR but not a CO catalyst. A minimum of 4 acres has been estimated for land requirements for the simple cycle installation and a minimum of 10 acres has been estimated for land requirements for a combined cycle installation. Figures 15-1 through 15-4 are typical site layouts assumed to support the proposed facility. Land requirements for a combined cycle installation would be adequate for multiple simple cycle units.

15.1.2 Fuel Supply

A suitable supply of natural gas would be needed to ensure project viability. Currently all of the natural gas supply pipelines in Wyandotte County are reportedly fully subscribed, meaning the natural gas supply available for the new unit installation has to be considered interruptible. Therefore, No. 2 ultra low sulfur fuel oil will be required as backup fuel supply for all installations. It has been assumed for this study that a three-day supply of fuel oil is required to be kept onsite in case of natural gas supply interruption.

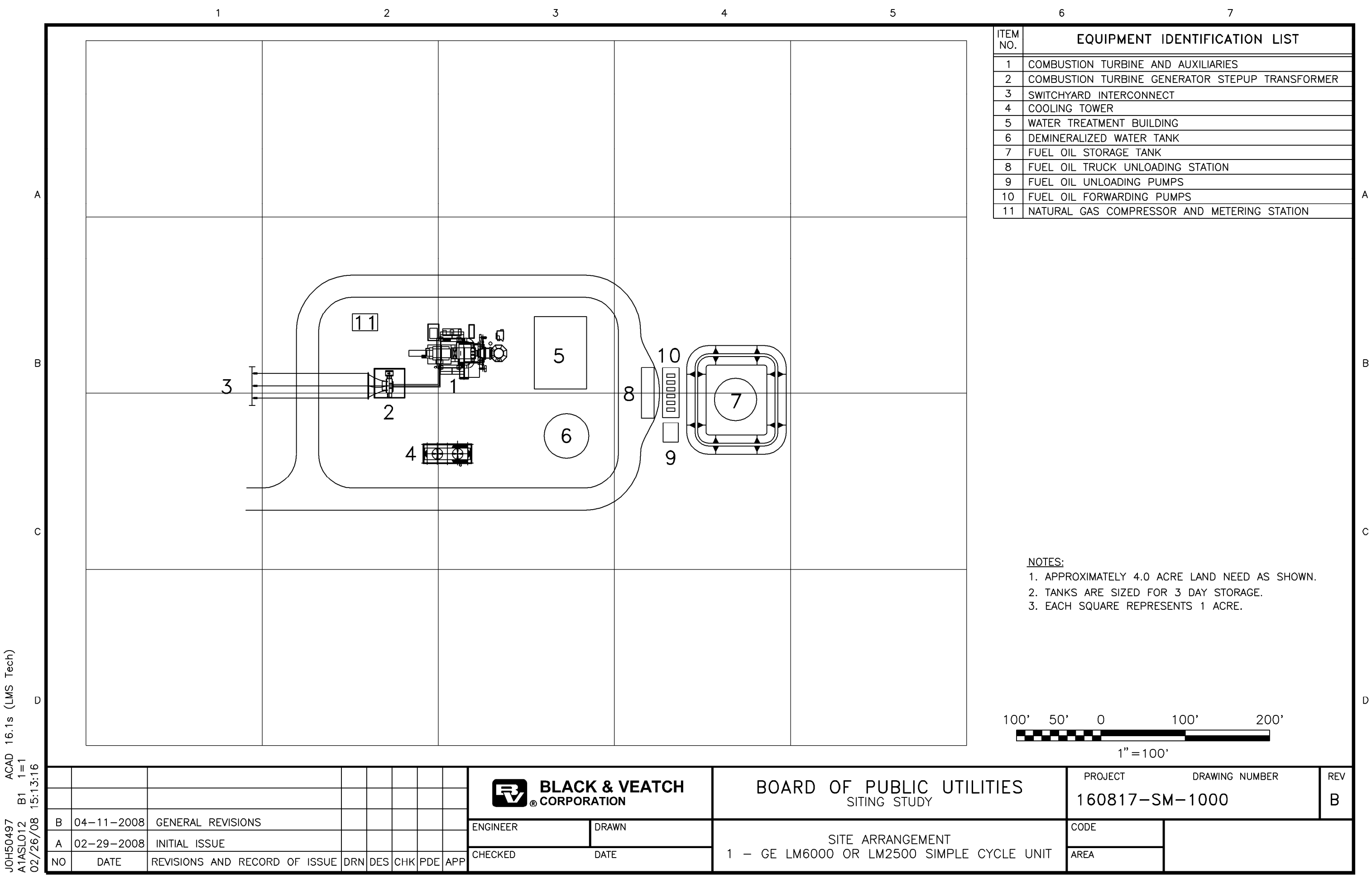


Figure 15-1
Generation Area Arrangement
1- GE LM6000 or LM2500 Simple Cycle Unit

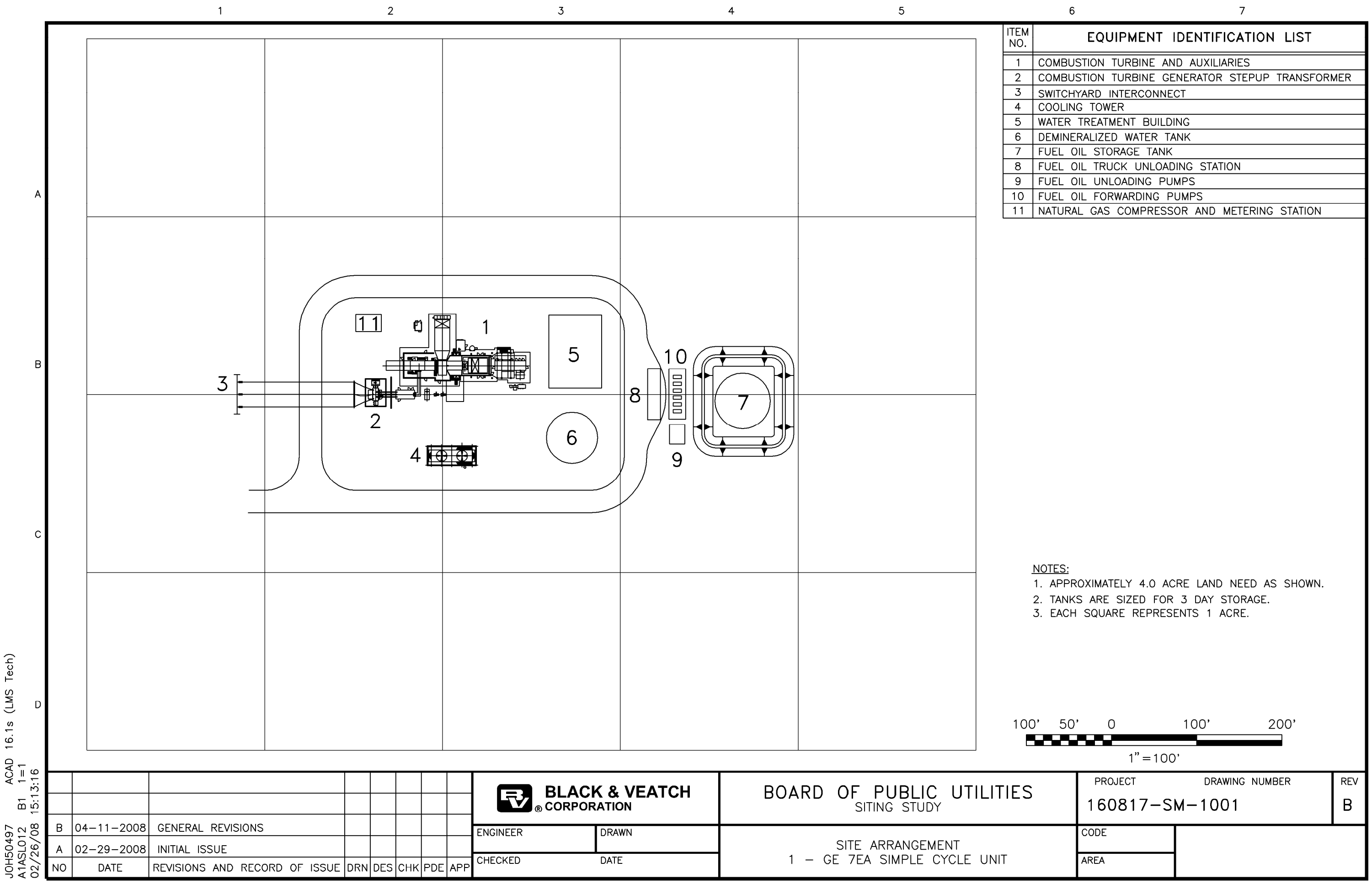


Figure 15-2
Generation Area Arrangement
1- GE 7EA Simple Cycle Unit

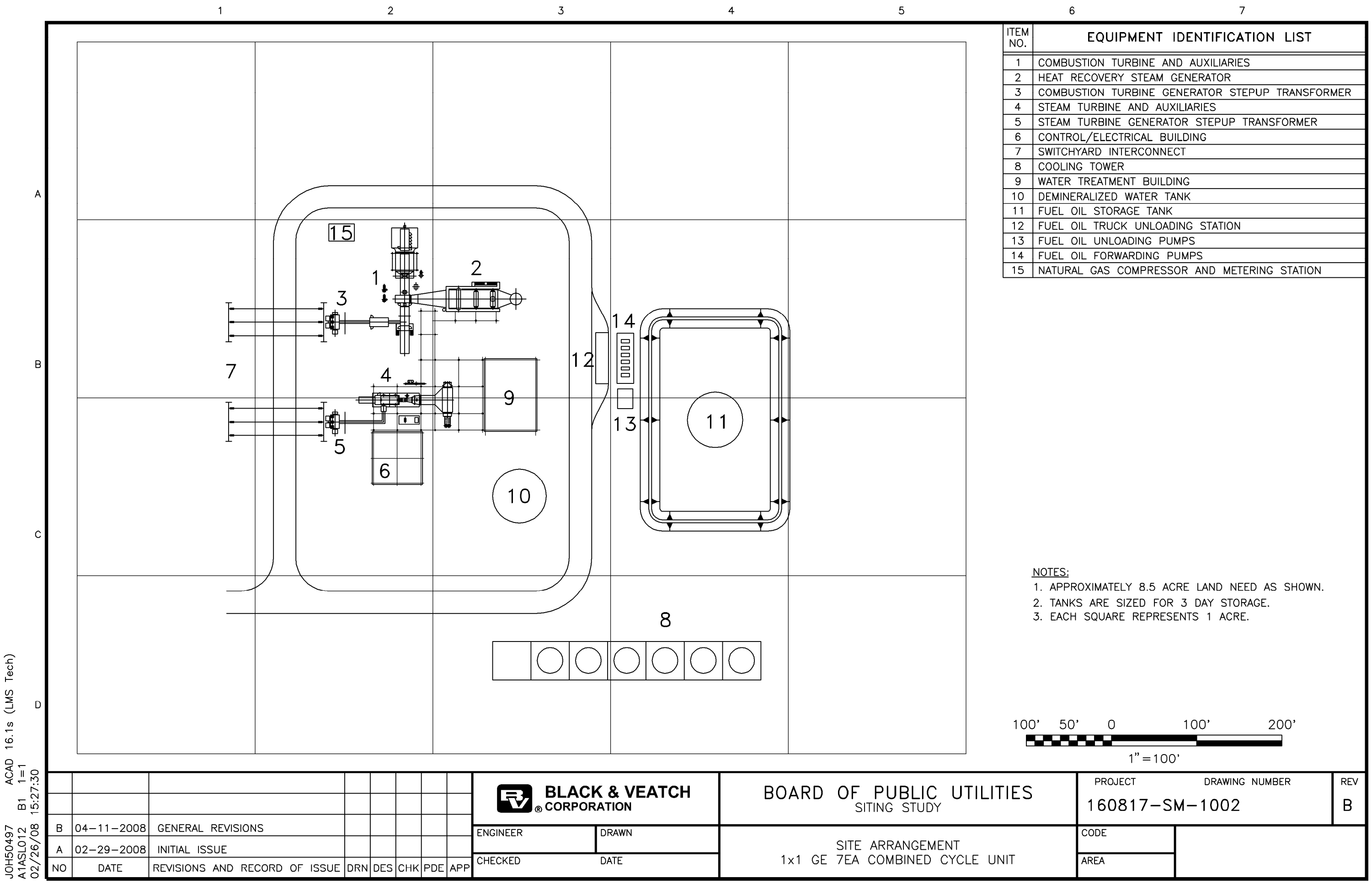


Figure 15-3
Generation Area Arrangement
1x1- GE 7EA Combined Cycle Unit

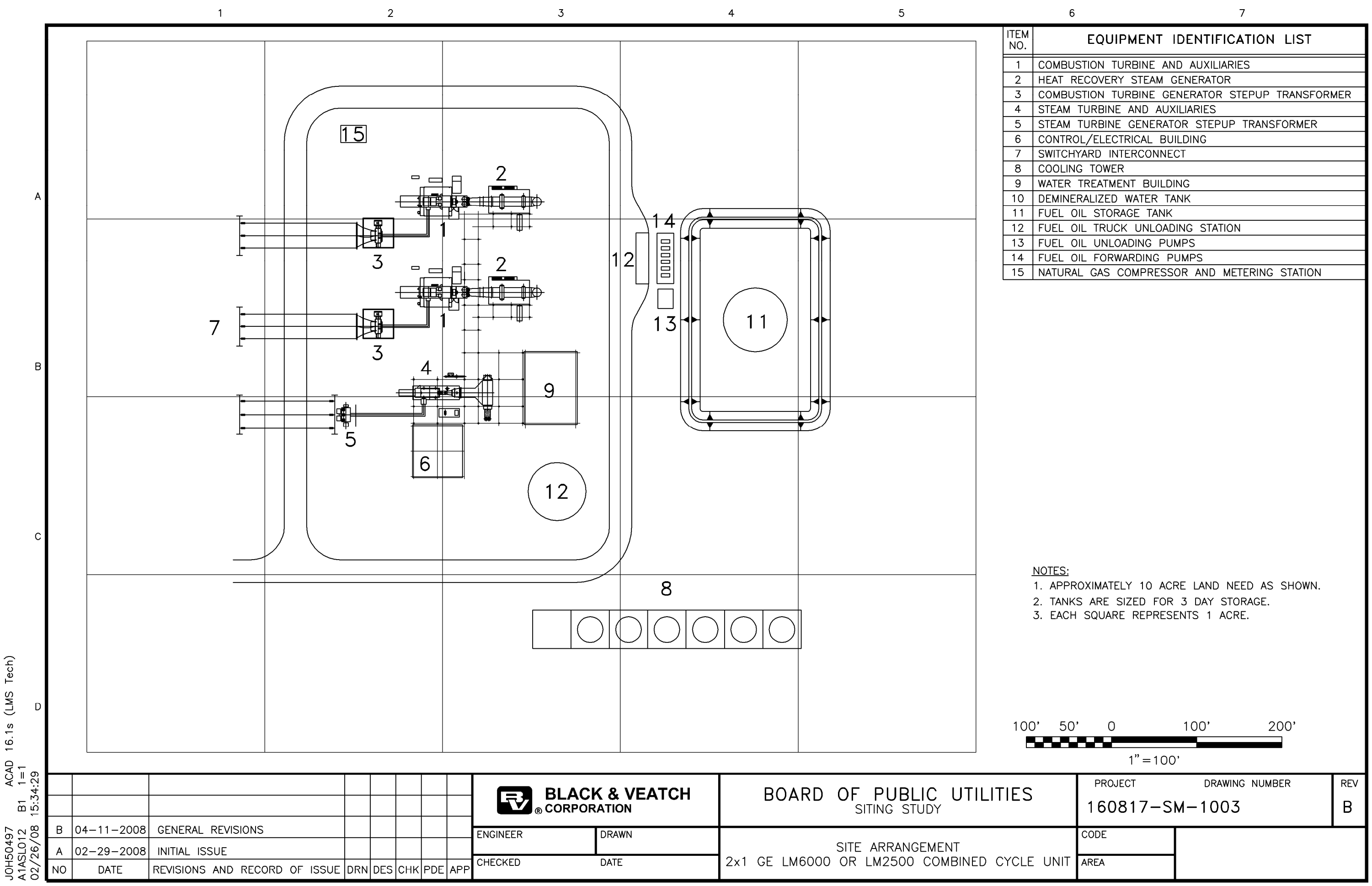


Figure 15-4
Generation Area Arrangement
2x1- GE LM6000 or LM2500 Combined Cycle Unit

15.1.3 Electric Transmission

Based on preliminary analysis of the BPU transmission system, BPU has indicated the new generation should be installed at and connected to the existing transmission system at existing power plant sites or substation sites. BPU has indicated they are currently in the process of upgrading their transmission system and that the new unit should be connected at the 161 kV level. It is anticipated BPU will conduct load flow studies to determine the appropriate interconnection requirements to the existing grid system for the selected site to determine the site-specific impacts. For the purposes of this study, new transmission lines were assumed to connect the generation site to the nearest point of interconnection to the existing BPU grid.

15.1.4 Water

Water consumption for a simple cycle combustion turbine is estimated to be between 60 and 100 gpm (0.09 to 0.15 million gallons per day [mgd]) under normal operation. Water consumption for a combined cycle unit is estimated to be between 120 and 1,700 gpm (0.17 and 2.45 mgd) under normal operation. For the simple cycle unit approximately 90 percent of the water will be used for water injection for NO_x control. For the combined cycle unit between 50 and 80 percent of the water will be used for evaporative cooling purposes and water injection for NO_x control with the remainder being used for boiler feedwater, cleaning, and other miscellaneous uses.

For the combined cycle unit, cooling water is recirculated, but large amounts of water are lost due to evaporation in the cooling towers. The mechanical draft cooling towers proposed for the project are evaporative cooling towers, meaning that water is cooled as heat energy is utilized to vaporize a portion of the circulating water to the atmosphere.

It has been assumed for the purposes of this study that all water requirements will be met by connection to and supply from the BPU city water system.

15.1.5 Storm Water and Wastewater Discharges

Storm water and wastewater from the project will be handled by storm water and wastewater treatment systems. For existing power plant sites, discharge of these wastes will be through permitted discharge points. For existing substation sites it has been assumed for the purposes of this study that all wastewater discharges will be to existing city sewer systems with treatment at the sewage treatment plants. The necessary National Pollutant Discharge Elimination System (NPDES) permits and approvals for the storm water and wastewater discharges will need to be obtained and coordinated with the operators of the wastewater treatment plants.

The primary wastewater discharges from the simple cycle installation will be occasional washdown and process drains for maintenance. Operating drains are normally collected in a drains tank and removed from site by a contractor. The primary wastewater discharges from the combined cycle unit would be blowdown from the cooling tower.

Blowdown from the cooling tower for the combined cycle unit on existing power plant sites will be treated onsite to achieve the water quality required for diversion to a NPDES-permitted discharge point. Blowdown from the cooling tower for a combined cycle unit on an existing substation site will be routed to the municipal sewer system.

Best management practices will be utilized for storm water discharge to ensure that erosion and sedimentation are minimized and applicable water quality standards are met. Sanitary wastes will be treated by an onsite system or discharged to a municipal system.

15.1.6 Economic Considerations

Economic considerations are a key factor in any site selection process. Efforts were made to identify the major cost differentials between the candidate sites. The impacts of site-specific economics were based on the professional judgment of those most knowledgeable of the particular factors.

16.0 Identification of Potential Sites

The study region was defined as the existing power plant sites and existing or planned future substation sites in Wyandotte County as shown on Figure 16-1. The initial screening of the sites narrowed the focus of the study by determining the technical requirements of the project and excluding all sites not having, or planned to have, 161 kV transmission interconnections or adequate natural gas supplies within one mile. The remaining sites were additionally screened by review of available area and some site reconnaissance.

16.1 Evaluation Criteria

Project evaluation criteria are necessary to evaluate the features of a siting area for identification of potential sites. These initial criteria included socioeconomic, land use, air quality, site development, and availability of personal and security.

16.1.1 Socioeconomics

Noise, traffic, and sensitive areas were considered. Information regarding noise, traffic, and residents was gathered during visits to the various sites. Sensitive areas included national, state, and local parks, wilderness areas, and other public use areas. Highway maps, topographic maps, and similar maps were the primary sources used to identify the sensitive resources in the project area.

16.1.2 Land Use/Zoning/Ownership

Land ownership and local zoning/land use compatibility information was gathered from information provided by BPU and during visits to the potential siting areas in February 2008. The information, especially land ownership, should be considered provisional since complete research of county records was not conducted and this information may not be completely up to date.

16.1.3 Air Quality

A new stationary source can be defined as a “major stationary source” if it is classified as any one of the listed major source categories which emits, or has the potential to emit, 100 tpy or more of any regulated pollutant. A new stationary source can also be defined as a “major stationary source” if it does not fall under one of the listed major source categories and which emits, or has the potential to emit, 250 tpy or more of any regulated pollutant.

The new stationary source would be considered a “minor stationary source” if it is not determined to be a major source.

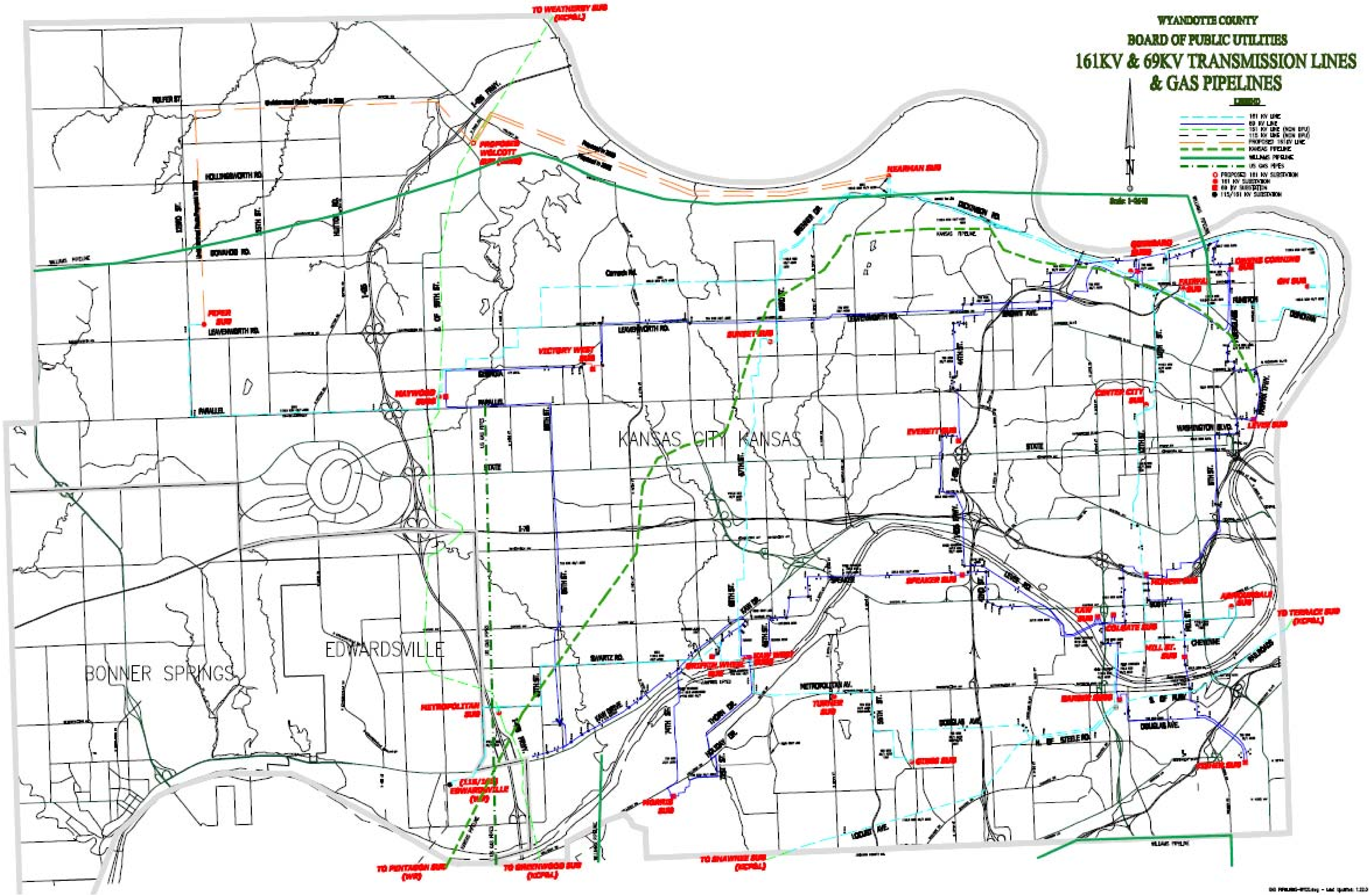


Figure 16-1
Wyandotte County Area 161 kV and 69 kV Transmission Lines and Natural Gas Pipelines

Each candidate site was assessed as to whether a major or minor air construction permit would be required. For the base case, it is assumed that a major air construction permit will be required for installation of a combined cycle unit at any site. For the alternate case for installation of a simple cycle unit, it is assumed that a major air construction permit will be required for installation at an existing power generating site and a minor air construction permit will be required at sites which currently do not have power generating units.

Air quality impact is a broad-ranging topic that can be evaluated with numerous indices of varying levels of importance in the air permitting process. Several air quality indices which were not considered in this evaluation included the presence of nearby nonattainment/maintenance areas, distances to nearby Class I areas, number of Class I areas located within 300 km (approximately 186 miles) of a potential site, and presence of existing nearby sources of air pollution, as the indices are all very similar for the candidate sites because of there relative proximity and not therefore a discriminating factor. Once a unit type and size along with the site is selected, a further detailed analysis of the air permitting and other environmental issues should be completed.

16.1.4 Site Development

Site development factors include the potential ease of development, availability of common facilities, and differential site development costs. Location of natural gas supply, electric transmission system requirements, water supply availability, transportation, and development constraints, are described in the following subsections.

16.1.4.1 Natural Gas Supply. The sites were further refined by identifying sites in close proximity to existing natural gas supplies. There are two viable existing natural gas supply pipeline systems currently installed in Wyandotte County, Williams/Southern Star and Kansas Pipeline. Figure 16-1 depicts the location of these natural gas lines. Gas compression will be required for the LM2500 and LM6000 combustion turbines and may be required for the 7EA combustion turbines.

16.1.4.1.1 Williams/Southern Star Pipeline. The pipeline currently shown as Williams Pipeline on the drawings has become, through a series of name changes, Southern Star. Southern Star is a locally managed, private company owned by GE’s Energy Financial Services business and Caisse de dépôt et placement du Québec.

Southern Star is headquartered in Owensboro, Kentucky. Southern Star currently operates one main pipeline generally running east-west across the northern part of Wyandotte County. This pipeline currently operates at 500 psig, but is reported to be upgradeable to 750 psig operating pressure. The Williams/Southern Star line currently supplies natural gas to BPU’s Nearman CT-4 and to Quest MidStream Partners, LP who transfers the natural gas through a 3 mile pipeline to Quindaro.

16.1.4.1.2 Kansas Pipeline. Kansas Pipeline Company engages in the owning and operation of regulated natural gas pipeline systems. Kansas Pipeline Company was acquired by Midcoast Energy Resources, Inc. in 1999. Midcoast Energy Resources Inc. was acquired by Enbridge Inc. in 2001 and later rolled into Enbridge Energy Partners, LP in 2002. In 2007 Enbridge began the process of selling its ownership of the Kansas Pipeline Company to Quest MidStream Partners, LP. The Kansas Pipeline currently installed and operating in Wyandotte County enters Wyandotte County from the south near Edwardsville and runs generally in a northeast direction until it gets to the northern side of the county, where it runs east and back to the south. This pipeline currently operates at 500 psig.

16.1.4.1.3 Kansas Gas Service. Kansas Gas Service is the local distribution company supplying natural gas to industrial, commercial, and residential customers in Kansas City, Kansas. The BPU's Kaw Power Station is one of the industrial customers receiving gas from Kansas Gas Service at a 50 psig supply pressure. Kansas Gas Service is connected to both Williams /Southern Star and Kansas Pipelines.

16.1.4.2 Electric Transmission System Requirements. The electrical transmission system that is required for this project will have a voltage of 161 kV. The main electrical transmission system in Wyandotte County area is shown on Figure 16-1. BPU has not conducted preliminary load flow studies to help identify suitable interconnection points to the existing grid system for proposed new capacity. These studies should be completed after the siting study is completed to verify the site interconnection.

16.1.4.3 Water Supply Availability. The primary water resources within the study area were assumed to be available as city water from the BPU water system. Estimates for distance to existing city water sources were made for differential site development costs. Actual distances and availability of water supply will need to be confirmed based on selected unit type and size at the selected site.

16.1.4.4 Development Constraints. Site topography and additional land area availability both need to be considered and may present development constraints or have significant cost impacts. In addition, nearby existing or future development and zoning requirements also may present a development constraint. Major transportation facilities such as highways are a preferred infrastructure resource when selecting siting areas and potential sites. The construction and/or improvement of roads between existing facilities and sites can have significant environmental and cost impacts.

16.2 Environmental Criteria

Only the evaluations of the potential major or minor air construction permit requirements were evaluated in this study. Other than the issues considered under socioeconomics, environmental criteria such as location relative to known environmentally sensitive areas, such as designated parks or recreation areas, wildlife areas, major wetlands areas, major residential areas, Prevention of Significant Deterioration (PSD) Class I areas, and ecologically sensitive areas including protected species habitats and cultural resources were not part of this siting study.

16.3 Identification of Potential Sites

Following the established methodology, the next step in the site selection process was the identification of potential sites within the defined siting areas. All three existing BPU power plant sites were included along with all twenty-six existing or planned BPU substation sites. The drawing included as Figure 16-1 herein identifies all of these locations.

At the gross screening level, all sites were reviewed with respect to the transmission system voltage available and the natural gas supply availability and location. All sites which do not currently have or do not have future planned access to transmission interconnection at 161 kV were eliminated from further consideration. All sites which were further than 1.0 mile from an existing natural gas pipeline were eliminated from further consideration. The results of the gross screening of the potential sites are shown in Table 16-1. Based on the results of the gross screening the following 19 sites were eliminated.

- Maywood
- Edwardsville
- Victory West
- Morris
- Griffin Wheel
- Kaw West
- Turner
- Everett
- Speaker
- Gibbs
- Center City
- Colgate
- Muncie

Table 16-1
Potential Sites – Gross Screening

Site ID	Available Transmission Voltages				Available Natural Gas (Miles)			Consider
	69 kV	115 kV	161 kV	Transmission Comments	Kansas Pipeline	Southern Star	Gas Comments	
Power Plant Sites								
Nearman			X		0.7	0.2		Yes
Quindaro	X		X		0.2	0.9		Yes
Kaw	X		Future		*	*		Yes
Substation Sites								
Piper			X		6.0	1.0		Yes
Wolcott			Future	Build in a year w/ KCPL inter-tie	4.3	0.4		Yes
Maywood	X		X		2.7	2.7	Exceeds 1.0 mile limit	No
Metropolitan			X	BPU & Non-BPU	0.3	1.4		Yes
Edwardsville		X	X	Not a BPU sub	0.5	1.9		No
Victory West	X			No 161 kV	1.4	2.3	Exceeds 1.0 mile limit	No
Morris	X			No 161 kV	2.2	1.0		No
Griffin Wheel	X			Customer Sub**	1.5	1.9	Exceeds 1.0 mile limit	No
Kaw West	X		X	Voltage and Grid support advantage	2.0	2.3	Exceeds 1.0 mile limit	No
Sunset			X		0.3	1.8		Yes
Turner			X		3.1	3.0	Exceeds 1.0 mile limit	No
Everett	X			No 161 kV	2.8	3.2	Exceeds 1.0 mile limit	No
Speaker	X			No 161 kV	4.3	3.7	Exceeds 1.0 mile limit	No
Gibbs			X		4.5	2.0	Exceeds 1.0 mile limit	No
Center City			X		1.4	1.6	Exceeds 1.0 mile limit	No
Colgate	X			No 161 kV	*	*		No
Muncie	X		Future		2.8	3.4	Exceeds 1.0 mile limit	No
Mill Street	X			Customer Sub**	3.6	2.3	Exceeds 1.0 mile limit	No
Barber	X		X	Land is available	4.4	1.8	Exceeds 1.0 mile limit	No

Table 16-1 Continued)
Potential Sites – Gross Screening

Site ID	Available Transmission Voltages				Available Natural Gas (Miles)			Consider
	69 kV	115 kV	161 kV	Transmission Comments	Kansas Pipeline	Southern Star	Gas Comments	
Fairfax			X		0.2	0.37		Yes
Owens Corning	X			Customer Sub**	0.6	0.3		No
General Motors			X	Positive Grid Load, Land is available	*	*		Yes
Levee	X			Future – Sub to be abandoned	0.5	1.6		No
Armourdale			X		2.9	2.9	Exceeds 1.0 mile limit	No
Fisher	X			No 161 kV	4.8	1.1	Exceeds 1.0 mile limit	No
New East Fairfax			X		*	*		Yes

*These sites are served by Kansas Gas Service distribution system operating at 50 psig.
**Customer Substation serves only a single industrial client.

- Mill Street
- Barber
- Owens Corning
- Levee
- Armourdale
- Fisher

The following 10 sites were identified as potential candidate sites.

- Nearman
- Quindaro
- Kaw
- Piper
- Wolcott
- Metropolitan
- Sunset
- Fairfax
- General Motors
- New East Fairfax

16.4 Identification of Candidate Sites

From the list of potential sites identified in Section 16.3 above, a total of 10 potential sites were identified. The remaining ten sites were reviewed with BPU and in most cases visited to identify sites which clearly can not support a new generation facility because of existing or future transmission system characteristics, space availability, or neighborhood limitations. This evaluation resulted in eliminating the following sites from consideration for new generation as described below.

- Piper is a newer substation located in a rapidly developing residential area. It is very close to existing schools and is not considered suitable for location of future generation.
- Metropolitan is a small substation located in a lightly developed suburban agricultural area with a few houses in the immediate area. The terrain of the site could be modified to tightly install a simple cycle combustion turbine only and is not suitable for multiple simple cycle units or a combined cycle unit.
- Sunset substation is a small existing neighborhood substation which does not have space for future generation. It is located in an existing neighborhood with single family house located immediately adjacent to the site.

- Fairfax is a small substation which is land limited. There is not additional land available to accommodate installation of any future generation.
- A new East Fairfax substation has been considered by BPU which could be located north of the existing Owens Corning Substation and south of the Missouri River. Space is available to accommodate either simple cycle or combined cycle combustion turbine generation. This potential site is very close to the General Motors site, therefore it was eliminated in favor of the General Motors site.

As a result, the initial twenty-nine sites were screened to ten potential sites then screened to five candidate sites after further research and site reconnaissance.

Listed below are the five candidate sites considered favorable for the intended project within the defined study area (i.e., candidate sites):

- Nearman Power Station.
- Quindaro Power Station.
- Kaw Power Station.
- Wolcott Substation.
- General Motors Substation.

The next step in the site selection process was the evaluation of the individual candidate sites using the siting criteria/scoring system described in Section 17.0 to identify the preferred and alternate sites.

17.0 Evaluation of Candidate Sites

The evaluation of candidate sites used a scoring system developed specifically for this siting study as described in this section. Preferred and alternate sites were ultimately identified by the scoring process. The evaluation and scoring criteria are provided in Appendix D.

17.1 Scoring System

The scoring system evaluates the siting objectives, which are predetermined factors or criteria considered to be important during the site selection process. The weighting factors assigned for this activity are based on a judgment of the relative importance for this application. A weighting system (percent format) is applied to the scoring categories to assign a relative level of importance. Each site is evaluated for each siting criterion by assigning a score (1 to 10) for that criterion. Each score is then multiplied by the criterion's percentage weight and summed to determine a total score. The sites can then be ranked based on the numerical scores. The preferred and alternate sites are typically selected from the top ranked sites.

The siting criteria and associated percentage weights are listed below, as agreed upon by the project team:

Evaluation Criteria
Socioeconomics – 15 percent
Land Use – 15 percent
Air Quality – 25 percent
Site Development – 25 percent
Location of Personnel and Security – 20 percent

Site development costs were estimated during the evaluations. These costs considered only those major items determined to be appreciably different between the candidate sites. The items considered are described in Appendix D. The differential site costs are presented in Table 17-1 for Combined Cycle Unit and in Table 17-2 for Simple Cycle Units. Project costs can be separated into two categories: the power block capital costs and site development costs. The total power block capital costs for generating facilities were assumed to be the same for a given type/technology, regardless of location.

Table 17-1
Differential Site Development Costs – Combined Cycle Unit

			Candidate Sites									
			Power Plant Sites						Substation Sites			
			Nearman		Quindaro		Kaw		Wolcott		General Motors	
Site Development Activity	Unit Cost $1,000 (2008)	Unit	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)
Transmission Interconnection (Note 1)	$0	N/A	0	$0	0	$0	0	$0	0	$0	0	$0
Substation Improvements/Exp.												
Existing Substation	$2,000	each	1	$2,000	1	$2,000	1	$2,000			1	$2,000
New Planned Substation	$1,000	each							1	$1,000		
Access Road	$170	mile	0	$0	0	$0	0	$0	0.5	$85	0	$0
Natural Gas Supply Pipeline - 12"	$1,600	mile	0.2	$320	0.2	$320	0.2	$320	0.4	$640	0.2	$320
Natural Gas Compression	$1,300	each	1	$1,300	1	$1,300	1	$1,300	1	$1,300	1	$1,300
Fuel Oil Tank (Note 2) - 500,000 gal.	$750	each	0	$0	0	$0	1	$750	1	$750	1	$750
Water Supply Pipeline - 12"	$500	mile	0.2	$100	0.2	$100	0.2	$100	1	$500	0.2	$100
Demineralizer (Note 3)	$1,000	each	0	$0	0	$0	0	$0	1	$1,000	1	$1,000
Demineralized Water Tank (Note 4) - 500,000 gal.	$1,000	each	0	$0	0	$0	0	$0	1	$1,000	1	$1,000
Wastewater Pipeline - 4"	$450	mile	0.2	$90	0.2	$90	0.2	$90	1	$450	0.2	$90
Land Acquisition (Note 5)	$5	acre	0	$0	0	$0	0	$0	10	$50	10	$50
Site Preparation	$10	acre	0	$0	10	$100	10	$100	10	$100	10	$100
TOTAL SITE DIFFERENTIAL DEVELOPMENT COSTS				$3,810		$3,910		$4,660		$6,875		$6,710
LOWEST SITE DIFFERENTIAL DEVELOPMENT COSTS				Base		$100		$850		$3,065		$2,900
SITE DIFFERENTIAL DEVELOPMENT COST SCORE				10		8		6		2		4

NOTES:
1. Transmission interconnection costs are assumed to be equal at each site.
2. Fuel oil tank assumed for 3 days storage at substation sites and existing fuel oil tanks are sufficient at power plant sites except Kaw.
3. Assume installation of a demineralizer system for the substation sites. A rental demineralizer system can also be used for substation sites. Assumes existing demineralizer systems will be used without modification at power plant sites.
4. Demineralized water tank same size as fuel oil tank for substation sites and existing demineralized tanks are sufficient at power plant sites.
5. Assumes land acquisition at substation sites is available and current owner is willing to sell.

Table 17-2
Differential Site Development Costs – Simple Cycle Unit

			Candidate Sites									
			Power Plant Sites						Substation Sites			
			Nearman		Quindaro		Kaw		Wolcott		General Motors	
Site Development Activity	Unit Cost $1,000 (2008)	Unit	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)	Differential Site Amount	Differential Site Cost ($1,000)
Transmission Interconnection (Note 1)	$0	N/A	0	$0	0	$0	0	$0	0	$0	0	$0
Substation Improvements/Exp.												
Existing Substation	$2,000	each	1	$2,000	1	$2,000	1	$2,000			1	$2,000
New Planned Substation	$1,000	each							1	$1,000		
Access Road	$170	mile	0	$0	0	$0	0	$0	0.5	$85	0	$0
Natural Gas Supply Pipeline - 12"	$1,600	mile	0.2	$320	0.2	$320	0.2	$320	0.4	$640	0.2	$320
Natural Gas Compression	$1,300	each	1	$1,300	1	$1,300	1	$1,300	1	$1,300	1	$1,300
Fuel Oil Tank (Note 2) - 400,000 gal.	$600	each	0	$0	0	$0	1	$600	1	$600	1	$600
Water Supply Pipeline - 6"	$400	mile	0.2	$80	0.2	$80	0.2	$80	1	$400	0.2	$80
Demineralizer (Note 3)	$1,000	each	0	$0	0	$0	0	$0	1	$1,000	1	$1,000
Demineralized Water Tank (Note 4) - 400,000 gal.	$800	each	0	$0	0	$0	0	$0	1	$800	1	$800
Wastewater Pipeline - 4"	$450	mile	0.2	$90	0.2	$90	0.2	$90	1	$450	0.2	$90
Land Acquisition (Note 5)	$5	acre	0	$0	0	$0	0	$0	4	$20	4	$20
Site Preparation	$10	acre	0	$0	10	$100	4	$40	4	$40	4	$40
TOTAL SITE DIFFERENTIAL DEVELOPMENT COSTS				$3,790		$3,890		$4,430		$6,335		$6,250
LOWEST SITE DIFFERENTIAL DEVELOPMENT COSTS				Base		$100		$640		$2,545		$2,460
SITE DIFFERENTIAL DEVELOPMENT COST SCORE				10		8		6		2		4

NOTES:
1. Transmission interconnection costs are assumed to be equal at each site.
2. Fuel oil tank assumed for 3 days storage at substation sites and existing fuel oil tanks are sufficient at power plant sites except Kaw.
3. Assume installation of a demineralizer system for the substation sites. A rental demineralizer system can also be used for substation sites. Assumes existing demineralizer systems will
4. Demineralized water tank same size as fuel oil tank for substation sites and existing demineralized tanks are sufficient at power plant sites.
5. Assumes land acquisition at substation sites is available and current owner is willing to sell.

Table 17-3 and the associated scoring were performed based on the installation of a combined cycle unit. Table 17-4 and the associated scoring were performed based on the installation of a single simple cycle unit. It should be noted that it is not considered practical to explore the effect of varying the weightings assigned to each individual siting factor because of the virtually infinite number of possible combinations.

17.2 Scoring Results

Black & Veatch personnel evaluated each site against the siting criteria and assigned a score (1 to 10) to each siting factor, with 1 representing a worst-case scenario and 10 representing the best case scenario. The scores assigned to each site are presented in Tables 17-3 and 17-4.

The top two sites for both cases were Nearman and Quindaro. The Kaw site ranked third. An explanation of the scoring and ranking for each site is provided in Section 17.3.

17.3 Candidate Site Scoring

An explanation of the scoring of each candidate site is provided in the following subsections.

17.3.1 Nearman Power Plant Site

The Nearman site is an existing BPU power plant located in Wyandotte County, Kansas. This site scored first in both cases.

17.3.1.1 Socioeconomics. The Nearman site scored lower than other candidate sites for noise and sensitive areas. There is a moderate density residential area south of the plant, and several municipal parks in the area. Parkville, Missouri, is located across the Missouri River, north-northeast from the plant. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.1.2 Land Use. The Nearman site is currently owned by BPU, contains a 161 kV substation, and is approved, zoned, and used for power generation and was scored the highest in these areas. The areas immediately adjacent to the site are agricultural. Residential areas are located within approximately one mile south and north of the property boundary.

Table 17-3
Evaluation Scores of Candidate Sites – Combined Cycle Unit

			Sites				
			Power Plant Sites			Substation Sites	
Evaluation Criteria	Weighting Factor, %		Nearman	Quindaro	Kaw	Wolcott	GM
1.0 Socioeconomic							
1.1 Noise	5		1	1	6	1	6
1.2 Traffic	5		10	10	10	10	10
1.3 Sensitive Area	5		4	2	6	2	6
Weighted Group Total	15		0.75	0.65	1.10	0.65	1.10
2.0 Land Use							
2.1 Land Ownership	5		10	10	10	10	10
2.2 Site Location	5		10	10	10	5	5
2.3 Zoning/Land Use Compatibility	5		10	10	10	5	10
Weighted Group Total	15		1.50	1.50	1.50	1.00	1.25
3.0 Air Quality							
3.1 Air Permit Required (Major/Minor)	25		5	5	5	5	5
Weighted Group Total	25		1.25	1.25	1.25	1.25	1.25
4.0 Site Development							
4.1 Ease of Development	8		10	5	5	1	10
4.2 Availability of Common Facilities	8		10	10	10	1	1
4.3 Differential Site Development Costs*	9		10	8	6	2	4
Weighted Group Total	25		2.50	1.92	1.74	0.34	1.24
5.0 Availability of Personnel (O&M) & Security							
5.1 Availability of Personnel	10		10	10	5	1	1
5.2 Security	10		10	10	10	1	10
Weighted Group Total	20		2.00	2.00	1.50	0.20	1.10
Weighted Total	100		8.00	7.32	7.09	3.44	5.94

*Refer to Table 17-1.

Table 17-4
Evaluation Scores of Candidate Sites – Simple Cycle Unit

		Sites				
		Power Plant Sites			Substation Sites	
Evaluation Criteria	Weighting Factor, %	Nearman	Quindaro	Kaw	Wolcott	GM
1.0 Socioeconomic						
1.1 Noise	5	1	1	6	1	6
1.2 Traffic	5	10	10	10	10	10
1.3 Sensitive Area	5	4	2	6	2	6
Weighted Group Total	15	0.75	0.65	1.10	0.65	1.10
2.0 Land Use						
2.1 Land Ownership	5	10	10	10	10	10
2.2 Site Location	5	10	10	10	5	5
2.3 Zoning/Land Use Compatibility	5	10	10	10	5	10
Weighted Group Total	15	1.50	1.50	1.50	1.00	1.25
3.0 Air Quality						
3.1 Air Permit Required (Major/Minor)	25	5	5	5	10	10
Weighted Group Total	25	1.25	1.25	1.25	2.50	2.50
4.0 Site Development						
4.1 Ease of Development	8	10	10	10	1	10
4.2 Availability of Common Facilities	8	10	10	10	1	1
4.3 Differential Site Development Costs*	9	10	8	6	2	4
Weighted Group Total	25	2.50	2.32	2.14	0.34	1.24
5.0 Availability of Personnel (O&M) & Security						
5.1 Availability of Personnel	10	10	10	5	1	1
5.2 Security	10	10	10	10	1	10
Weighted Group Total	20	2.00	2.00	1.50	0.20	1.10
Weighted Total	100	8.00	7.72	7.49	4.69	7.19

*Refer to Table 17-2.

17.3.1.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the Nearman site scored lower than the substation ("Greenfield") sites as a major air construction permit would still be required on a site which already has operating generating units.

17.3.1.4 Site Development. The Nearman site scored the highest in all site development areas. The site is already developed for addition of a second simple cycle or combined cycle unit, has available common facilities, and had the lowest site development costs.

17.3.1.5 Availability of Personnel and Security. The Nearman site is currently an operating power generating site with personnel on site 24 hours a day, 365 days per year. Personnel to support the operation and maintenance of a new natural gas generating unit are available, or would be available with only minor staffing increases. The site is currently secure with boundary fencing and 24-hour security personnel on site.

17.3.2 Quindaro Power Plant Site

The Quindaro site is an existing BPU power plant located in Wyandotte County, Kansas. This site scored second in both cases.

17.3.2.1 Socioeconomics. The Quindaro site scored lower than other candidate sites for noise and sensitive areas. Although located in a primarily industrial area, there is moderate density residential areas near the plant, the Missouri River is adjacent to the site, and there are cultural resources (Quindaro ruins) located near the site. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.2.2 Land Use. The Quindaro site is currently owned by BPU, contains a 161 kV substation, and is approved, zoned, and used for power generation and was scored the highest in these areas. The areas immediately adjacent to the site to the north and east are all industrial. Residential areas are located just south of the property boundary.

17.3.2.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the Quindaro site scored lower than the substation ("Greenfield") sites as a major air construction permit would still be required on a site which already has operating generating units.

17.3.2.4 Site Development. The Quindaro site scored the second highest of all sites in site development areas. The site would require some development for installation of a new simple cycle unit or combined cycle unit, has available common facilities, and had the second lowest site development costs.

17.3.2.5 Availability of Personnel and Security. The Quindaro site is currently an operating power generating site with personnel on site 24 hours a day, 365 days per year. Personnel to support the operation and maintenance of a new natural gas generating unit are available, or would be available with only minor staffing increases. The site is currently secure with boundary fencing and 24-hour security personnel on site.

17.3.3 Kaw Power Plant Site

The Kaw site is an existing BPU power plant located in Wyandotte County, Kansas. This site scored third in both cases.

17.3.3.1 Socioeconomics. The Kaw site scored higher than the other power plant sites and substation sites for noise and sensitive areas. Located in a primarily industrial area, without residential areas near the plant, but the Kansas River is adjacent to the site. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.3.2 Land Use. The Kaw site is currently owned by BPU, contains a 69 kV substation, and is approved, zoned, and used for power generation and was scored the highest in these areas. There are plans by BPU to convert the substation to 161 kV in the future.

17.3.3.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the Kaw site scored lower than the substation (“Greenfield”) sites as a major air construction permit would still be required on a site which already has potential to operate existing generating units.

17.3.3.4 Site Development. The Kaw site scored the third highest of all sites in site development areas. The site would require some development for installation of a new simple cycle unit or combined cycle unit, has some available common facilities, and had the third lowest site development costs.

17.3.3.5 Availability of Personnel and Security. The Kaw site is currently a standby (formerly operating) power generating site with limited personnel (one full time and one part time person) onsite for limited periods. Personnel to support the operation and maintenance of a new natural gas generating unit would need to be added or supplemented from existing staff from the other power plants. The site is currently secure with boundary fencing and 24-hour security personnel on site.

17.3.4 Wolcott Substation Site

The Wolcott substation site is a future planned BPU substation site located in Wyandotte County, Kansas. This site scored the lowest in both cases.

17.3.4.1 Socioeconomics. The Wolcott site scored lower than other candidate sites for noise and sensitive areas. Although currently located in a primarily agricultural area, there are residential developments planned nearby, the Missouri river is near the site, and the Wyandotte County Lake and park areas are nearby. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.4.2 Land Use. The Wolcott site is currently owned by BPU and is planned to be zoned for use as a substation. Zoning for use for power generation would need to be pursued. In addition, BPU has been approached by a developer requesting the substation be moved to the west side of Interstate 435 to allow for further development on the east side of the highway. The areas immediately around the site are currently undeveloped, but future residential areas are reportedly planned to be located adjacent to or near the property boundary.

17.3.4.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the Wolcott site scored higher as a greenfield site that the power plant sites as only a minor air construction permit would be required.

17.3.4.4 Site Development. The Wolcott site scored the lowest of all sites in site development areas. The site would require significant development for installation of a new simple cycle unit or combined cycle unit, has no available common facilities, and had the highest site development costs.

17.3.4.5 Availability of Personnel and Security. The Wolcott site is currently an undeveloped site which would need the addition of operating and maintenance personnel. If a combined cycle unit were installed, personnel to support 24 hours a day, 365 days per year would be required. If a simple cycle unit was installed, remote operation could be possible with personnel support for monitoring and maintenance supplied from the existing power plants on a traveling basis. The site would need to be secured with boundary fencing and full time security personnel would need to be added or remote monitored security systems would need to be installed.

17.3.5 General Motors Substation

The General Motors substation site is an existing BPU substation site located in Wyandotte County, Kansas. This site scored fourth in both cases.

17.3.4.1 Socioeconomics. The General Motors site scored higher than other power plant sites and substation sites for noise and sensitive areas. Located in a primarily industrial area, without residential areas near the plant, but the Missouri River is near the site. All sites scored high for traffic without any significant traffic impacts other than for short durations during construction activities.

17.3.4.2 Land Use. The General Motors site is currently owned by General Motors/BPU and is zoned for use as heavy industrial. Purchase of land from General Motors and zoning for use for power generation would need to be pursued. The areas immediately adjacent to the site in all directions are industrial with the Missouri River nearby to the north.

17.3.4.3 Air Quality. The base case was for installation of a combined cycle unit. In all cases, installation of a combined cycle unit will require a major air construction permit. All sites were scored the same. For the alternate case, with installation of a simple cycle unit, the General Motors site scored higher as a greenfield site than the power plant sites as only a minor air construction permit would be required.

17.3.4.4 Site Development. The General Motors site scored next to lowest of all sites in site development areas. The site would require significant development for installation of a new simple cycle unit or combined cycle unit, has no available common facilities, and had the next to highest site development costs.

17.3.4.5 Availability of Personnel and Security. The General Motors site is currently a non-generating site which would need the addition of operating and maintenance personnel. If a combined cycle unit were installed, personnel to support 24 hours a day, 365 days per year would be required. If a simple cycle unit was installed, remote operation could be possible with personnel support for monitoring and maintenance supplied from the existing power plants on a traveling basis. The site is highly secured by General Motors with boundary fencing and full time security personnel.

17.4 Preferred and Alternate Sites

On the basis of the analyses conducted, the Nearman site is the preferred site for the development of additional natural gas fired generation in the siting area. The Nearman site has had the highest weighted score and has the infrastructure in place to support additional natural gas fired generation. It scored better or equal to other sites in almost all criteria and scored better than the other power plant sites in site development.

The alternate site selected is the Quindaro site. The site had the second highest score on both the base case and the alternate case. The site development will be slightly more involved and costly than the Nearman site. Otherwise, it scored similar to the Nearman site in most criteria.

18.0 Site Selection Study
Summary and Conclusions

Black & Veatch, on behalf of BPU, conducted a site selection study to identify potential sites for installation of natural gas fired generating units. Existing power plant sites and substation sites in Wyandotte County were identified as the potential siting areas for study.

Evaluation criteria were developed to provide adequate information to assess site and resource requirements. The criteria were based on an installation of a simple cycle combustion turbine or installation of a combined cycle unit. Potential natural gas fuel sources, water sources, and wastewater discharge facilities were identified. A minimum 161 kV transmission connection was required. A site of at least 4 acres was required for the simple cycle installation and of at least 10 acres for a combined cycle unit. The siting region was screened to determine potential sites, and ultimately candidate sites. The requirements included socioeconomic factors (noise, traffic, and sensitive areas), land use, air permit requirements, site development issues and costs, and availability of personnel and security.

Twenty-nine sites were identified for evaluation based on current or future planned BPU power plant and substation sites. The twenty-nine sites were reduced to ten sites based on available transmission voltages and available natural gas. Evaluation of the ten potential sites, which included reconnaissance of most sites, eliminated five additional sites from further consideration. The remaining five sites were considered the candidate sites.

The candidate sites were evaluated in greater detail using the established evaluation criteria and scoring system. The scores were weighted to assign a relative level of importance. The sites were then ranked based on the scoring results of each scenario.

The preferred site is Nearman for either a simple cycle or combined cycle unit. The Quindaro site was selected as the first alternate site.

Appendix A
PROSYM Electric System Simulation Model

Appendix A
PROSYM Electric System Simulation Model

PROSYM is a general-purpose simulation model capable of representing most electric load and resource situations. PROSYM is a complete electric utility/regional pool analysis and accounting system. It is designed for performing planning and operational studies, and as a result of its chronological structure, accommodates detailed hour-by-hour (or by half hour increments, if desired) investigation of the operations of electric utilities and pools. Because of its ability to handle detailed information in a chronological fashion, planning studies performed with PROSYM closely reflect actual operations. PROSYM was the first second-generation chronological model, with new technology that vastly sped up the simulation process that used open standards for both input and reporting to link up with the latest software tools. Now, it is the first third-generation model, capable of analysis not only in the traditional cost-based world, but also in the rapidly evolving pools and free markets for power worldwide.

The model uses a Microsoft Windows-compatible user interface and file system, which it shares with several other Ventyx models. The interface provides an environment in which data sets are easily created and edited, and simulations run. PROSYM is fully integrated with a database system, which works natively with Microsoft Access 2.0 (and later), but can be tailored to work with any PC or Unix-based database system that is ODBC-compliant (most are).

PROSYM uses a powerful data input method capable of handling the large volume of information required to perform highly detailed studies of electric generation and pool operation. This data input method gives maximum control with a minimum of effort. The grammar enables you to modify key variables as frequently as hourly, and results in a data set which is easy to review and virtually self-documenting. PROSYM is the flagship of a family of related models and add-on modules that use common input-output methods and procedures to solve a host of problems associated with the generation and sale of electricity.

The MULTISYM module converts PROSYM into a true multi-area model with power transport limitations honored. While PROSYM operates in Star mode, with all transmission-limited areas connected to the main system and all power paths predetermined, MULTISYM can additionally operate in Delta mode, in which the system consists of independent, connected transmission areas with various power routes possible, depending on system topology. In Delta mode, transmission areas can be grouped into control areas for additional spinning reserve control. MULTISYM is a superset of PROSYM; it can process any PROSYM data set (in Star mode) in addition to its own.

Another module, ECOSYM, allows the model to perform system dispatch with both economic and environmental factors considered. This helps in emissions studies and expansion planning under the Clean Air Act.

To perform simulations, the PROSYM system requires: at least one basic set of annual hourly loads; projections of peak loads and energies on a weekly, monthly, seasonal or annual basis for the study of any future period; and data representing the physical and economic operating characteristics (the resource mix) of the electric utility or pool, and any relevant pool or ISO rules.

Electric utilities and generation pools operate generation resources, energy storage devices, and load control systems to match generation and load on an instantaneous basis. This real-time operation entails using highly sophisticated control systems which match generation levels with load virtually instantaneously. It is not analytically necessary to represent this level of time detail in performing planning studies which have a time horizon of weeks to years. What is necessary is a level of time detail that allows the planning study to obtain a reasonable approximation of actual system operation. Hourly time steps can accommodate the modeling of virtually any utility or pool situation, so the basic time unit used in PROSYM is one hour (a half-hour version is available for use in certain pools). In each hour of a study period, PROSYM considers a complex set of operating constraints to simulate the least-cost operation of the utility, or least-bid operation of the pool. This hour-by hour simulation, respecting chronological, operational, and other constraints in the case of cost based dispatch, and relevant pool or independent system operator (ISO) rules in the case of bid based dispatch, is the essence of the model.

Appendix B
Comparison of Phase I Revenue Requirements

Q0-A: Q1 Retires in 2011, Add GE 7EA in 2011 and convert the new GE 7EA to Combined Cycle in 2012

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cos ($1,000)	Constructio Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	48,850	9	01/01/2011	59,775	5,595
Convert 7EA to 1x1 CC	87,650	24	01/01/2012	109,293	10,230

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs*[4] *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$75,194	$3,597	$32,969	$4,702	-$2,743	$18,441	-$15,771	$0	$116,390	$5,595	$5,802	$11,396	$127,786	$395,709
2012	2,644	$79,262	$4,958	$34,874	$11,618	-$4,898	$19,134	-$14,707	$0	$130,241	$15,825	$5,802	$21,626	$151,868	$519,468
2013	2,669	$79,979	$5,084	$36,108	$12,351	-$4,256	$24,311	-$14,818	$0	$138,760	$15,825	$5,802	$21,626	$160,386	$643,649
2014	2,697	$88,740	$7,916	$39,612	$11,952	-$5,312	$16,033	-$16,415	$0	$142,526	$15,825	$25,336	$41,161	$183,687	$778,777
2015	2,721	$93,954	$8,290	$40,211	$13,250	-$5,877	$16,913	-$16,717	$0	$150,025	$15,825	$25,336	$41,161	$191,186	$912,406
2016	2,733	$96,782	$8,386	$40,972	$14,779	-$6,117	$18,077	-$17,072	$0	$155,808	$15,825	$25,336	$41,161	$196,969	$1,043,210
2017	2,744	$100,101	$8,547	$41,662	$16,437	-$6,627	$19,500	-$17,325	$0	$162,296	$15,825	$25,336	$41,161	$203,456	$1,171,582
Levelized Cost($1000):		$78,561	$5,439	$36,415	$9,506	-$5,202	$16,596	-$15,546	$0	$125,770	$9,109	$11,033	$20,143	$145,912	
NPV:		$630,795	$43,674	$292,392	$76,325	-$41,766	$133,257	-$124,828	$0	$1,009,849	$73,143	$88,590	$161,733	$1,171,582	
Levelized Cost($/MWh):		$23.75	$1.64	$11.01	$2.87	-$1.57	$5.02	-$4.70	$0.00	$38.02	$2.75	$3.34	$6.09	$44.11	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-B: Q1 Retires in 2011, Convert CT4 to Combined Cycle in 2011 and add LM6000s in 2011 and 2015

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Convert 7EA to 1x1 CC	93,190	24	01/01/2011	119,841	11,217
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461
LM6000 SCCT	42,270	10	01/01/2015	46,660	4,909

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	2011

Year	Served Load (GWh)	Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	Capital Cost: AQC Capital Cost ($1,000)	Capital Cost: *Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$77,107	$4,535	$34,002	$4,683	-$4,292	$12,447	-$15,771	$0	$112,710	$16,678	$5,802	$22,479	$135,190	$402,059
2012	2,644	$80,703	$5,044	$34,939	$11,656	-$5,074	$16,653	-$14,707	$0	$129,215	$16,678	$5,802	$22,479	$151,694	$525,677
2013	2,669	$80,376	$5,114	$36,209	$12,332	-$4,274	$23,145	-$14,818	$0	$138,085	$16,678	$5,802	$22,479	$160,564	$649,996
2014	2,697	$90,002	$7,972	$39,715	$11,945	-$5,671	$14,330	-$16,415	$0	$141,878	$16,678	$25,336	$42,014	$183,892	$785,275
2015	2,721	$94,766	$8,310	$41,017	$13,366	-$7,077	$14,356	-$16,719	$0	$148,019	$21,587	$25,336	$46,922	$194,942	$921,529
2016	2,733	$98,326	$8,448	$41,790	$14,907	-$7,199	$14,935	-$17,071	$0	$154,137	$21,587	$25,336	$46,922	$201,059	$1,055,049
2017	2,744	$101,429	$8,620	$42,496	$16,514	-$7,536	$16,896	-$17,325	$0	$161,095	$21,587	$25,336	$46,922	$208,017	$1,186,299
Levelized Cost($1000):		$79,368	$5,569	$36,755	$9,532	-$5,685	$14,749	-$15,547	$0	$124,741	$11,971	$11,033	$23,005	$147,745	
NPV:		$637,276	$44,715	$295,118	$76,533	-$45,647	$118,421	-$124,829	$0	$1,001,588	$96,121	$88,590	$184,712	$1,186,299	
Levelized Cost($/MWh):		$23.99	$1.68	$11.11	$2.88	-$1.72	$4.46	-$4.70	$0.00	$37.71	$3.62	$3.34	$6.95	$44.66	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-C: Q1 Retires in 2011, Add 2LM6000s in 2011. Convert the LM6000s to combined cycle in 2012.

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	42,270	10	01/01/2011	51,909	4,859
LM6000 SCCT	42,270	10	01/01/2011	51,909	4,859
LM6000 2x1 CC Phased Construction	65,180	14	01/01/2012	78,428	7,341

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs*[4] *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$76,616	$3,606	$33,594	$4,704	-$3,268	$13,733	-$15,771	$0	$113,214	$9,717	$5,802	$15,519	$128,732	$396,521
2012	2,644	$81,119	$4,767	$35,406	$11,686	-$5,648	$16,096	-$14,707	$0	$128,718	$17,058	$5,802	$22,860	$151,578	$520,044
2013	2,669	$84,656	$5,179	$36,650	$12,490	-$5,624	$18,482	-$14,818	$0	$137,015	$17,058	$5,802	$22,860	$159,875	$643,829
2014	2,697	$91,180	$7,699	$40,164	$12,026	-$6,494	$12,890	-$16,416	$0	$141,048	$17,058	$25,336	$42,394	$183,442	$778,777
2015	2,721	$94,365	$7,885	$40,772	$13,307	-$6,464	$15,266	-$16,717	$0	$148,414	$17,058	$25,336	$42,394	$190,808	$912,142
2016	2,733	$97,546	$8,062	$41,543	$14,831	-$7,128	$16,521	-$17,071	$0	$154,305	$17,058	$25,336	$42,394	$196,699	$1,042,767
2017	2,744	$100,982	$8,241	$42,243	$16,499	-$7,628	$17,695	-$17,326	$0	$160,705	$17,058	$25,336	$42,394	$203,099	$1,170,914
Levelized Cost($1000):		$79,744	$5,324	$36,781	$9,547	-$5,788	$14,521	-$15,547	$0	$124,583	$10,213	$11,033	$21,247	$145,829	
NPV:		$640,294	$42,748	$295,325	$76,657	-$46,471	$116,594	-$124,829	$0	$1,000,318	$82,005	$88,590	$170,596	$1,170,914	
Levelized Cost($/MWh):		$24.11	$1.61	$11.12	$2.89	-$1.75	$4.39	-$4.70	$0.00	$37.66	$3.09	$3.34	$6.42	$44.08	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-D: Q1 Retires in 2011, Add GE 7EA in 2011 and LM6000 in 2013

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	48,850	9	01/01/2011	59,775	6,288
LM6000 SCCT	42,270	10	01/01/2013	48,431	5,095

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs 4* (*$1,000*)	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* (*$1,000*)	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$75,194	$3,597	$32,969	$4,702	-$2,743	$18,441	-$15,771	$0	$116,390	$6,288	$5,802	$12,090	$128,480	$396,304
2012	2,644	$76,176	$3,796	$33,887	$11,518	-$2,787	$26,896	-$14,707	$0	$134,779	$6,288	$5,802	$12,090	$146,869	$515,989
2013	2,669	$78,867	$4,132	$35,776	$12,363	-$3,361	$27,927	-$14,818	$0	$140,886	$11,383	$5,802	$17,185	$158,071	$638,378
2014	2,697	$88,666	$6,800	$39,274	$12,005	-$3,956	$18,265	-$16,415	$0	$144,639	$11,383	$25,336	$36,719	$181,358	$771,793
2015	2,721	$93,288	$6,996	$39,867	$13,322	-$4,493	$19,668	-$16,717	$0	$151,932	$11,383	$25,336	$36,719	$188,651	$903,650
2016	2,733	$95,162	$7,127	$40,623	$14,801	-$4,300	$22,296	-$17,071	$0	$158,639	$11,383	$25,336	$36,719	$195,358	$1,033,384
2017	2,744	$97,931	$7,266	$41,306	$16,430	-$4,667	$24,289	-$17,326	$0	$165,229	$11,383	$25,336	$36,719	$201,948	$1,160,805
Levelized Cost($1000):		$77,771	$4,810	$36,165	$9,509	-$4,352	$18,902	-$15,546	$0	$127,259	$6,277	$11,033	$17,311	$144,570	
NPV:		$624,453	$38,621	$290,385	$76,351	-$34,945	$151,773	-$124,828	$0	$1,021,811	$50,404	$88,590	$138,994	$1,160,805	
Levelized Cost($/MWh):		$23.51	$1.45	$10.93	$2.87	-$1.32	$5.71	-$4.70	$0.00	$38.47	$1.90	$3.34	$5.23	$43.70	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-E: Q1 Retires in 2011, Add two LM6000 in 2011 and one LM6000 in 2013

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461
LM6000 SCCT	42,270	10	01/01/2013	48,431	5,095

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M: Variable[2] ($1,000)	O&M: Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$76,616	$3,606	$33,594	$4,704	-$3,268	$13,733	-$15,771	$0	$113,214	$10,922	$5,802	$16,723	$129,937	$397,554
2012	2,644	$80,957	$3,980	$34,522	$11,699	-$3,878	$18,434	-$14,707	$0	$131,006	$10,922	$5,802	$16,723	$147,729	$517,940
2013	2,669	$82,241	$4,261	$36,424	$12,496	-$4,453	$22,429	-$14,818	$0	$138,580	$16,016	$5,802	$21,818	$160,398	$642,130
2014	2,697	$91,029	$6,955	$39,934	$12,116	-$5,332	$13,796	-$16,415	$0	$142,083	$16,016	$25,336	$41,352	$183,435	$777,073
2015	2,721	$96,058	$7,132	$40,539	$13,466	-$5,820	$14,418	-$16,717	$0	$149,077	$16,016	$25,336	$41,352	$190,430	$910,174
2016	2,733	$97,688	$7,188	$41,305	$14,943	-$5,485	$16,832	-$17,072	$0	$155,400	$16,016	$25,336	$41,352	$196,752	$1,040,834
2017	2,744	$101,779	$7,375	$42,001	$16,642	-$6,383	$17,955	-$17,326	$0	$162,044	$16,016	$25,336	$41,352	$203,396	$1,169,169
Levelized Cost($1000):		$79,703	$4,881	$36,589	$9,592	-$5,099	$15,194	-$15,547	$0	$125,314	$9,264	$11,033	$20,298	$145,612	
NPV:		$639,961	$39,195	$293,787	$77,015	-$40,939	$122,000	-$124,829	$0	$1,006,190	$74,388	$88,590	$162,978	$1,169,169	
Levelized Cost($/MWh):		$24.09	$1.48	$11.06	$2.90	-$1.54	$4.59	-$4.70	$0.00	$37.88	$2.80	$3.34	$6.14	$44.02	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q0-F: Q1 Retires in 2011, Add LM6000 in 2011 and GE 7EA in 2012

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	48,850	9	01/01/2012	57,738	6,074
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$76,392	$3,543	$32,943	$4,705	-$2,687	$15,942	-$15,771	$0	$115,067	$5,461	$5,802	$11,262	$126,329	$394,460
2012	2,644	$78,740	$3,915	$34,551	$11,668	-$3,674	$21,832	-$14,707	$0	$132,324	$11,535	$5,802	$17,336	$149,660	$516,420
2013	2,669	$78,867	$4,132	$35,776	$12,363	-$3,361	$27,927	-$14,818	$0	$140,886	$11,535	$5,802	$17,336	$158,222	$638,926
2014	2,697	$88,666	$6,800	$39,274	$12,005	-$3,956	$18,265	-$16,415	$0	$144,639	$11,535	$25,336	$36,871	$181,510	$772,452
2015	2,721	$93,288	$6,996	$39,867	$13,322	-$4,493	$19,668	-$16,717	$0	$151,932	$11,535	$25,336	$36,871	$188,802	$904,415
2016	2,733	$95,162	$7,127	$40,623	$14,801	-$4,300	$22,296	-$17,071	$0	$158,639	$11,535	$25,336	$36,871	$195,509	$1,034,250
2017	2,744	$97,931	$7,266	$41,306	$16,430	-$4,667	$24,289	-$17,326	$0	$165,229	$11,535	$25,336	$36,871	$202,100	$1,161,766
Levelized Cost($1000):		$78,160	$4,816	$36,230	$9,525	-$4,436	$18,122	-$15,546	$0	$126,869	$6,788	$11,033	$17,821	$144,690	
NPV:		$627,570	$38,670	$290,903	$76,476	-$35,620	$145,504	-$124,828	$0	$1,018,676	$54,500	$88,590	$143,091	$1,161,766	
Levelized Cost($/MWh):		$23.63	$1.46	$10.95	$2.88	-$1.34	$5.48	-$4.70	$0.00	$38.35	$2.05	$3.34	$5.39	$43.74	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 and Carbon allowance costs. Carbon regulations begins in 2012.

Q1-A: Add GE 7EA in 2011

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	48,850	9	01/01/2011	59,775	6,288

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015		

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$77,304	$3,817	$36,575	$5,500	-$5,854	$9,223	-$15,771	$0	$110,794	$6,288	$5,802	$12,090	$122,884	$391,504
2012	2,644	$79,170	$4,496	$38,586	$13,555	-$6,262	$14,030	-$14,707	$0	$128,866	$6,288	$12,238	$18,527	$147,393	$511,617
2013	2,669	$82,292	$4,869	$40,114	$14,484	-$6,137	$16,285	-$14,818	$0	$137,089	$6,288	$12,238	$18,527	$155,616	$632,105
2014	2,697	$87,681	$7,279	$43,690	$14,030	-$6,235	$11,811	-$16,414	$0	$141,843	$6,288	$31,773	$38,061	$179,904	$764,450
2015	2,721	$93,175	$7,554	$44,363	$15,580	-$7,766	$12,080	-$16,714	$0	$148,272	$6,288	$31,773	$38,061	$186,333	$894,687
2016	2,733	$94,909	$7,672	$45,200	$17,154	-$7,515	$14,413	-$17,071	$0	$154,762	$6,288	$31,773	$38,061	$192,823	$1,022,738
2017	2,744	$96,943	$7,766	$45,960	$18,932	-$7,696	$15,966	-$17,327	$0	$160,543	$6,288	$31,773	$38,061	$198,604	$1,148,049
Levelized Cost($1000):		$78,432	$5,152	$38,986	$10,779	-$6,303	$12,931	-$15,546	$0	$124,432	$4,054	$14,496	$18,550	$142,981	
NPV:		$629,759	$41,369	$313,033	$86,548	-$50,605	$103,830	-$124,826	$0	$999,107	$32,551	$116,390	$148,942	$1,148,049	
Levelized Cost($/MWh):		$23.71	$1.56	$11.79	$3.26	-$1.91	$3.91	-$4.70	$0.00	$37.61	$1.23	$4.38	$5.61	$43.22	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

Q1-B: Add LM6000 in 2011

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	42,270	10	01/01/2011	51,909	5,461

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015		

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$78,411	$3,781	$36,548	$5,504	-$6,079	$7,279	-$15,771	$0	$109,674	$5,461	$5,802	$11,262	$120,936	$389,834
2012	2,644	$81,739	$4,565	$38,557	$13,608	-$6,483	$10,280	-$14,707	$0	$127,558	$5,461	$12,238	$17,699	$145,258	$508,206
2013	2,669	$83,390	$4,873	$40,087	$14,507	-$6,221	$13,743	-$14,818	$0	$135,561	$5,461	$12,238	$17,699	$153,261	$626,871
2014	2,697	$90,054	$7,362	$43,662	$14,123	-$7,236	$8,653	-$16,415	$0	$140,203	$5,461	$31,773	$37,234	$177,437	$757,401
2015	2,721	$95,059	$7,611	$44,334	$15,628	-$8,033	$8,878	-$16,717	$0	$146,761	$5,461	$31,773	$37,234	$183,994	$886,003
2016	2,733	$96,684	$7,691	$45,169	$17,202	-$7,651	$10,835	-$17,072	$0	$152,858	$5,461	$31,773	$37,234	$190,091	$1,012,240
2017	2,744	$99,404	$7,823	$45,931	$19,006	-$8,460	$12,145	-$17,326	$0	$158,522	$5,461	$31,773	$37,234	$195,756	$1,135,754
Levelized Cost($1000):		$79,639	$5,174	$38,968	$10,809	-$6,543	$10,934	-$15,547	$0	$123,434	$3,521	$14,496	$18,016	$141,450	
NPV:		$639,447	$41,548	$312,886	$86,792	-$52,538	$87,790	-$124,829	$0	$991,096	$28,268	$116,390	$144,658	$1,135,754	
Levelized Cost($/MWh):		$24.07	$1.56	$11.78	$3.27	-$1.98	$3.31	-$4.70	$0.00	$37.31	$1.06	$4.38	$5.45	$42.76	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

Q1-C: Add LM2500s in 2011 and 2015

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM2500 SCCT	28,000	10	01/01/2011	34,385	3,617
LM2500 SCCT	28,000	10	01/01/2015	30,908	3,252

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015		

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$76,635	$3,662	$36,525	$5,505	-$5,265	$9,444	-$15,771	$0	$110,735	$3,617	$5,802	$9,419	$120,154	$389,163
2012	2,644	$78,645	$4,361	$38,533	$13,489	-$5,516	$14,052	-$14,707	$0	$128,857	$3,617	$12,238	$15,856	$144,713	$507,091
2013	2,669	$81,175	$4,734	$40,062	$14,403	-$5,331	$16,538	-$14,818	$0	$136,763	$3,617	$12,238	$15,856	$152,619	$625,259
2014	2,697	$88,047	$7,233	$43,637	$14,005	-$6,164	$11,432	-$16,415	$0	$141,777	$3,617	$31,773	$35,390	$177,167	$755,590
2015	2,721	$91,647	$7,426	$44,984	$15,508	-$6,806	$12,095	-$16,717	$0	$148,137	$6,869	$31,773	$38,642	$186,779	$886,139
2016	2,733	$93,024	$7,483	$45,830	$17,055	-$6,651	$14,599	-$17,071	$0	$154,269	$6,869	$31,773	$38,642	$192,911	$1,014,248
2017	2,744	$95,963	$7,635	$46,603	$18,861	-$7,080	$15,557	-$17,326	$0	$160,213	$6,869	$31,773	$38,642	$198,855	$1,139,717
Levelized Cost($1000):		$77,867	$5,068	$39,122	$10,743	-$5,876	$12,931	-$15,546	$0	$124,309	$3,140	$14,496	$17,635	$141,944	
NPV:		$625,225	$40,691	$314,126	$86,256	-$47,181	$103,831	-$124,828	$0	$998,119	$25,208	$116,390	$141,599	$1,139,717	
Levelized Cost($/MWh):		$23.54	$1.53	$11.83	$3.25	-$1.78	$3.91	-$4.70	$0.00	$37.58	$0.95	$4.38	$5.33	$42.91	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

Q1-D: CT4 Conversion to Combined Cycle in 2011

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Convert 7EA to 1x1 CC	93,190	24	01/01/2011	119,841	11,217

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	38,894	6,437
Q2 LNB and OFA	10,701	2	01/01/2010	11,990	1,984
N1 LNB and OFA	20,586	2	01/01/2010	23,065	3,817
N1 Spray Dry Scrubber & Fabric Filter	110,189	25	01/01/2014	118,032	19,534

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015		

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	O&M Variable[2] ($1,000)	O&M Fixed ($1,000)	*Emission Costs[4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[3] ($1000)	Nearman Participant Sales ($1,000)	Bridge Power Purchase ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,127	$3,375	$33,590	$5,338	-$6,147	$10,780	-$14,943	$0	$95,121	$0	$0	$0	$95,121	$95,121
2009	2,570	$62,234	$3,490	$33,713	$5,150	-$5,453	$14,100	-$13,915	$0	$99,318	$0	$0	$0	$99,318	$189,486
2010	2,594	$65,518	$3,701	$34,756	$5,307	-$5,029	$12,100	-$15,122	$0	$101,232	$0	$5,802	$5,802	$107,033	$286,107
2011	2,635	$78,580	$4,623	$36,956	$5,470	-$6,929	$6,741	-$15,771	$0	$109,670	$11,217	$5,802	$17,019	$126,689	$394,768
2012	2,644	$81,749	$5,481	$38,974	$13,553	-$7,378	$9,052	-$14,707	$0	$126,725	$11,217	$12,238	$23,456	$150,180	$517,152
2013	2,669	$83,223	$5,620	$40,548	$14,441	-$6,763	$12,871	-$14,818	$0	$135,122	$11,217	$12,238	$23,456	$158,578	$639,933
2014	2,697	$89,796	$8,257	$44,132	$14,010	-$7,842	$7,843	-$16,415	$0	$139,780	$11,217	$31,773	$42,990	$182,770	$774,387
2015	2,721	$94,523	$8,559	$44,812	$15,502	-$8,547	$8,013	-$16,717	$0	$146,145	$11,217	$31,773	$42,990	$189,135	$906,583
2016	2,733	$97,173	$8,683	$45,654	$17,151	-$8,378	$8,647	-$17,071	$0	$151,860	$11,217	$31,773	$42,990	$194,850	$1,035,979
2017	2,744	$100,276	$8,863	$46,425	$18,952	-$9,476	$10,617	-$17,326	$0	$158,332	$11,217	$31,773	$42,990	$201,322	$1,163,005
Levelized Cost($1000):		$79,680	$5,758	$39,262	$10,764	-$7,017	$10,217	-$15,546	$0	$123,117	$7,232	$14,496	$21,727	$144,844	
NPV:		$639,781	$46,230	$315,246	$86,428	-$56,345	$82,036	-$124,828	$0	$988,549	$58,066	$116,390	$174,456	$1,163,005	
Levelized Cost($/MWh):		$24.09	$1.74	$11.87	$3.25	-$2.12	$3.09	-$4.70	$0.00	$37.22	$2.19	$4.38	$6.57	$43.79	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008).
(2) VOM column includes unit start-up cost including start-up fuel costs and includes additional variable costs associated with AQC retrofits.
(3) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(4) Emissions cost is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.

Appendix C
Phase I Sensitivity Case Revenue Requirements

Scenarios

	Q1 Retires 2011					Q1 No Change			
	Q0-A	**Q0-B**	**Q0-C ***	**Q0-D**	**Q0-E**	**Q1-A**	**Q1-B**	**Q1-C**	**Q1-D**
7EA CT	2011			2011		2011			
LM6000		2011 & 2015	2 in 2011	2013	2 in 2011, 2013		2011		
LM2500								2011 & 2015	
1x1 7EA CC	2012	2011							2011
2x1 LM6000 CC			2012						

Sensativities: **High & Low Load**: Loss or gain of a large (28 MW) customer, at a load factor similar to system load factor. Buy capacity in the gain case. (SPP allows short term (4 mo.) capacity purchase up to 25% of peak.)
High & Low Fuel and Market: Use Ventyx high and low NG and electric market forecast.
High Carbon Tax: Use Ventyx base and high CO_2 price forecast.
No Economy Purchases

Base Case

Base Plans	Levelized Annual Production Cost: Fuel Cost[1]	O&M Variable	O&M Fixed	*Emission Costs*	Economy Sales	Economy Purchase	Nearman Participant Sales	Net Production Cost	Levelized Annual Capital Cost: Unit Additions Capital Cost	AQC Capital Cost	*Total Capital Cost*	Levelized Total System Cost	Cumulative Present Worth Cost	Rank within Cat-egory	Rank within All Plans	% Difference From Least Cost Plan: Category	All Plans
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)				
Q1 Retires in 2011																	
Q0-A	$ 78,561	$ 5,439	$ 36,415	$ 9,506	$ (5,202)	$ 16,596	$ (15,546)	$ 125,770	$ 9,109	$ 11,033	$ 20,143	$ 145,912	$ 1,171,582	5	9	0.93%	3.15%
Q0-B	$ 79,368	$ 5,569	$ 36,755	$ 9,532	$ (5,685)	$ 14,749	$ (15,547)	$ 124,741	$ 11,971	$ 11,033	$ 23,005	$ 147,745	$ 1,186,299	6	10	2.20%	4.45%
Q0-C	$ 79,744	$ 5,324	$ 36,781	$ 9,547	$ (5,788)	$ 14,521	$ (15,547)	$ 124,583	$ 10,213	$ 11,033	$ 21,247	$ 145,829	$ 1,170,914	4	8	0.87%	3.10%
Q0-D	$ 77,771	$ 4,810	$ 36,165	$ 9,509	$ (4,352)	$ 18,902	$ (15,546)	$ 127,259	$ 6,277	$ 11,033	$ 17,311	$ 144,570	$ 1,160,805	1	4	**0.00%**	2.21%
Q0-E	$ 79,703	$ 4,881	$ 36,589	$ 9,592	$ (5,099)	$ 15,194	$ (15,547)	$ 125,314	$ 9,264	$ 11,033	$ 20,298	$ 145,612	$ 1,169,169	3	7	0.72%	2.94%
Q0-F	$ 78,160	$ 4,816	$ 36,230	$ 9,525	$ (4,436)	$ 18,122	$ (15,546)	$ 126,869	$ 6,788	$ 11,033	$ 17,821	$ 144,690	$ 1,161,766	2	5	**0.08%**	2.29%
Q1 Retires after 2017																	
Q1-A	$ 78,432	$ 5,152	$ 38,986	$ 10,779	$ (6,303)	$ 12,931	$ (15,546)	$ 124,432	$ 4,054	$ 14,496	$ 18,550	$ 142,981	$ 1,148,049	3	3	1.08%	1.08%
Q1-B	$ 79,639	$ 5,174	$ 38,968	$ 10,809	$ (6,543)	$ 10,934	$ (15,547)	$ 123,434	$ 3,521	$ 14,496	$ 18,016	$ 141,450	$ 1,135,754	1	1	**0.00%**	**0.00%**
Q1-C	$ 77,867	$ 5,068	$ 39,122	$ 10,743	$ (5,876)	$ 12,931	$ (15,546)	$ 124,309	$ 3,140	$ 14,496	$ 17,635	$ 141,944	$ 1,139,717	2	2	0.35%	0.35%
Q1-D	$ 79,680	$ 5,758	$ 39,262	$ 10,764	$ (7,017)	$ 10,217	$ (15,546)	$ 123,117	$ 7,232	$ 14,496	$ 21,727	$ 144,844	$ 1,163,005	4	6	2.40%	2.40%

Lose Large Customer

Base Plans	Levelized Annual Production Cost: Fuel Cost[1]	O&M Variable	O&M Fixed	*Emission Costs*	Economy Sales	Economy Purchase	Nearman Participant Sales	Net Production Cost	Levelized Annual Capital Cost: Unit Additions Capital Cost	AQC Capital Cost	*Total Capital Cost*	Levelized Total System Cost	Cumulative Present Worth Cost	Rank within Cat-egory	Rank within All Plans	% Difference From Least Cost Plan: Category	All Plans
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)				
Q1 Retires in 2011																	
Q0-A	$ 75,456	$ 5,276	$ 36,415	$ 9,333	$ (6,085)	$ 13,298	$ (15,546)	$ 118,147	$ 9,109	$ 11,033	$ 20,143	$ 138,290	$ 1,110,380	4	8	1.14%	2.96%
Q0-B	$ 75,917	$ 5,396	$ 36,755	$ 9,355	$ (6,396)	$ 11,728	$ (15,547)	$ 117,209	$ 11,971	$ 11,033	$ 23,005	$ 140,213	$ 1,125,822	6	10	2.55%	4.39%
Q0-C	$ 76,077	$ 5,102	$ 36,781	$ 9,361	$ (6,546)	$ 11,887	$ (15,546)	$ 117,116	$ 10,213	$ 11,033	$ 21,247	$ 138,362	$ 1,110,960	5	9	1.19%	3.01%
Q0-D	$ 74,298	$ 4,641	$ 36,165	$ 9,334	$ (5,191)	$ 15,722	$ (15,547)	$ 119,422	$ 6,277	$ 11,033	$ 17,311	$ 136,733	$ 1,097,878	1	4	**0.00%**	1.80%
Q0-E	$ 75,876	$ 4,680	$ 36,589	$ 9,404	$ (5,854)	$ 12,462	$ (15,547)	$ 117,611	$ 9,264	$ 11,033	$ 20,298	$ 137,909	$ 1,107,318	2	6	0.86%	2.68%
Q0-F	$ 75,876	$ 4,680	$ 36,589	$ 9,404	$ (5,854)	$ 12,462	$ (15,547)	$ 117,611	$ 9,264	$ 11,033	$ 20,298	$ 137,909	$ 1,107,318	2	6	0.86%	2.68%
Q1 Retires after 2017																	
Q1-A	$ 74,906	$ 4,962	$ 38,986	$ 10,506	$ (7,049)	$ 10,458	$ (15,547)	$ 117,222	$ 4,054	$ 14,496	$ 18,550	$ 135,771	$ 1,090,157	3	3	1.09%	1.09%
Q1-B	$ 75,716	$ 4,969	$ 38,968	$ 10,523	$ (7,233)	$ 8,901	$ (15,547)	$ 116,297	$ 3,521	$ 14,496	$ 18,016	$ 134,314	$ 1,078,452	1	1	**0.00%**	**0.00%**
Q1-C	$ 74,255	$ 4,882	$ 39,122	$ 10,471	$ (6,645)	$ 10,504	$ (15,547)	$ 117,044	$ 3,140	$ 14,496	$ 17,635	$ 134,679	$ 1,081,384	2	2	0.27%	0.27%
Q1-D	$ 76,170	$ 5,524	$ 39,262	$ 10,496	$ (7,769)	$ 7,943	$ (15,546)	$ 116,079	$ 7,232	$ 14,496	$ 21,727	$ 137,806	$ 1,106,497	4	5	2.60%	2.60%

Gain Large Customer

	Levelized Annual Production Cost								Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost[1]	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q1 Retires in 2011																	
Q0-A	$ 82,648	$ 5,677	$ 36,522	$ 9,638	$ (4,338)	$ 19,940	$ (15,546)	$ 134,541	$ 9,109	$ 11,033	$ 20,143	$ 154,684	$ 1,242,011	5	9	0.62%	3.28%
Q0-B	$ 83,419	$ 5,814	$ 36,861	$ 9,674	$ (4,847)	$ 17,832	$ (15,546)	$ 133,205	$ 11,971	$ 11,033	$ 23,005	$ 156,210	$ 1,254,264	6	10	1.61%	4.30%
Q0-C	$ 83,609	$ 5,544	$ 36,887	$ 9,670	$ (4,856)	$ 17,906	$ (15,546)	$ 133,214	$ 10,213	$ 11,033	$ 21,247	$ 154,461	$ 1,240,218	4	8	0.48%	3.13%
Q0-D	$ 81,652	$ 5,020	$ 36,272	$ 9,628	$ (3,437)	$ 22,832	$ (15,546)	$ 136,419	$ 6,277	$ 11,033	$ 17,311	$ 153,730	$ 1,234,354	1	5	**0.00%**	2.64%
Q0-E	$ 83,869	$ 5,087	$ 36,696	$ 9,726	$ (4,229)	$ 18,524	$ (15,547)	$ 134,127	$ 9,264	$ 11,033	$ 20,298	$ 154,424	$ 1,239,928	3	7	0.45%	3.11%
Q0-F	$ 82,186	$ 5,044	$ 36,230	$ 9,647	$ (3,557)	$ 21,932	$ (15,546)	$ 135,935	$ 6,788	$ 11,033	$ 17,821	$ 153,756	$ 1,234,561	2	6	**0.02%**	2.66%
Q1 Retires after 2017																	
Q1-A	$ 82,084	$ 5,338	$ 39,093	$ 10,985	$ (5,220)	$ 16,175	$ (15,547)	$ 132,907	$ 4,054	$ 14,496	$ 18,550	$ 151,457	$ 1,216,101	3	3	1.13%	1.13%
Q1-B	$ 83,150	$ 5,353	$ 39,074	$ 11,002	$ (5,196)	$ 13,918	$ (15,546)	$ 131,755	$ 3,521	$ 14,496	$ 18,016	$ 149,771	$ 1,202,568	1	1	**0.00%**	**0.00%**
Q1-C	$ 81,475	$ 5,249	$ 39,229	$ 10,933	$ (4,690)	$ 16,202	$ (15,547)	$ 132,850	$ 3,140	$ 14,496	$ 17,635	$ 150,485	$ 1,208,299	2	2	0.48%	0.48%
Q1-D	$ 83,567	$ 5,993	$ 39,368	$ 10,970	$ (5,909)	$ 12,776	$ (15,547)	$ 131,218	$ 7,232	$ 14,496	$ 21,727	$ 152,946	$ 1,228,055	4	4	2.12%	2.12%

High NG and MCP

	Levelized Annual Production Cost								Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost[1]	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q1 Retires in 2011																	
Q0-A	$ 75,592	$ 4,982	$ 36,415	$ 14,355	$ (5,770)	$ 17,120	$ (15,546)	$ 127,148	$ 9,109	$ 11,033	$ 20,143	$ 147,291	$ 1,182,653	5	9	0.98%	3.49%
Q0-B	$ 75,296	$ 5,055	$ 36,755	$ 14,361	$ (6,036)	$ 16,127	$ (15,547)	$ 126,012	$ 11,971	$ 11,033	$ 23,005	$ 149,017	$ 1,196,507	6	10	2.17%	4.71%
Q0-C	$ 76,418	$ 4,863	$ 36,781	$ 14,397	$ (6,319)	$ 15,430	$ (15,546)	$ 126,024	$ 10,213	$ 11,033	$ 21,247	$ 147,270	$ 1,182,486	4	8	0.97%	3.48%
Q0-D	$ 74,659	$ 4,443	$ 36,165	$ 14,386	$ (4,873)	$ 19,311	$ (15,547)	$ 128,545	$ 6,277	$ 11,033	$ 17,311	$ 145,856	$ 1,171,131	1	5	**0.00%**	2.48%
Q0-E	$ 74,658	$ 4,401	$ 36,589	$ 14,406	$ (5,508)	$ 17,599	$ (15,547)	$ 126,597	$ 9,264	$ 11,033	$ 20,298	$ 146,895	$ 1,179,474	3	7	0.71%	3.21%
Q0-F	$ 74,587	$ 4,425	$ 36,230	$ 14,392	$ (4,867)	$ 18,895	$ (15,547)	$ 128,116	$ 6,788	$ 11,033	$ 17,821	$ 145,937	$ 1,171,783	2	6	**0.06%**	2.54%
Q1 Retires after 2017																	
Q1-A	$ 75,335	$ 4,829	$ 38,986	$ 16,751	$ (7,135)	$ 12,315	$ (15,547)	$ 125,534	$ 4,054	$ 14,496	$ 18,550	$ 144,084	$ 1,156,903	3	3	1.24%	1.24%
Q1-B	$ 74,979	$ 4,785	$ 38,968	$ 16,741	$ (7,259)	$ 11,636	$ (15,547)	$ 124,304	$ 3,521	$ 14,496	$ 18,016	$ 142,320	$ 1,142,736	1	1	**0.00%**	**0.00%**
Q1-C	$ 74,525	$ 4,756	$ 39,122	$ 16,731	$ (6,815)	$ 12,194	$ (15,547)	$ 124,966	$ 3,140	$ 14,496	$ 17,635	$ 142,601	$ 1,144,994	2	2	0.20%	0.20%
Q1-D	$ 75,770	$ 5,296	$ 39,262	$ 16,696	$ (7,906)	$ 10,380	$ (15,546)	$ 123,950	$ 7,232	$ 14,496	$ 21,727	$ 145,678	$ 1,169,697	4	4	2.36%	2.36%

Low NG and MCP

	Levelized Annual Production Cost								Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost[1]	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q1 Retires in 2011																	
Q0-A	$ 72,591	$ 5,442	$ 36,415	$ 14,125	$ (6,130)	$ 8,446	$ (15,546)	$ 115,342	$ 9,109	$ 11,033	$ 20,143	$ 135,485	$ 1,087,859	5	5	0.98%	0.98%
Q0-B	$ 73,214	$ 5,611	$ 36,755	$ 14,123	$ (6,674)	$ 7,059	$ (15,547)	$ 114,540	$ 11,971	$ 11,033	$ 23,005	$ 137,545	$ 1,104,394	6	8	2.51%	2.51%
Q0-C	$ 73,591	$ 5,357	$ 36,781	$ 14,010	$ (6,702)	$ 6,548	$ (15,546)	$ 114,039	$ 10,213	$ 11,033	$ 21,247	$ 135,286	$ 1,086,258	3	3	0.83%	0.83%
Q0-D	$ 70,132	$ 4,649	$ 36,165	$ 14,415	$ (4,940)	$ 11,985	$ (15,547)	$ 116,860	$ 6,277	$ 11,033	$ 17,311	$ 134,171	$ 1,077,305	1	1	**0.00%**	**0.00%**
Q0-E	$ 71,471	$ 4,747	$ 36,589	$ 14,452	$ (6,031)	$ 9,496	$ (15,547)	$ 115,177	$ 9,264	$ 11,033	$ 20,298	$ 135,475	$ 1,087,777	4	4	0.97%	0.97%
Q0-F	$ 70,522	$ 4,670	$ 36,230	$ 14,434	$ (5,194)	$ 11,351	$ (15,547)	$ 116,467	$ 6,788	$ 11,033	$ 17,821	$ 134,288	$ 1,078,243	2	2	**0.09%**	**0.09%**
Q1 Retires after 2017																	
Q1-A	$ 71,917	$ 4,891	$ 38,986	$ 16,541	$ (5,936)	$ 8,522	$ (15,547)	$ 119,374	$ 4,054	$ 14,496	$ 18,550	$ 137,923	$ 1,107,435	3	9	1.07%	2.80%
Q1-B	$ 72,690	$ 4,940	$ 38,968	$ 16,512	$ (6,335)	$ 7,222	$ (15,547)	$ 118,451	$ 3,521	$ 14,496	$ 18,016	$ 136,467	$ 1,095,745	1	6	**0.00%**	1.71%
Q1-C	$ 72,512	$ 4,892	$ 39,122	$ 16,587	$ (5,835)	$ 7,582	$ (15,547)	$ 119,313	$ 3,140	$ 14,496	$ 17,635	$ 136,948	$ 1,099,605	2	7	0.35%	2.07%
Q1-D	$ 74,144	$ 5,698	$ 39,262	$ 16,128	$ (7,178)	$ 5,578	$ (15,546)	$ 118,085	$ 7,232	$ 14,496	$ 21,727	$ 139,812	$ 1,122,600	4	10	2.45%	4.20%

High Carbon Tax

	Levelized Annual Production Cost								Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost[1]	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q1 Retires in 2011																	
Q0-A	$ 79,468	$ 5,494	$ 36,415	$ 47,819	$ (6,059)	$ 19,785	$ (15,546)	$ 167,376	$ 9,109	$ 11,033	$ 20,143	$ 187,519	$ 1,505,657	4	7	0.60%	1.10%
Q0-B	$ 80,205	$ 5,624	$ 36,755	$ 47,952	$ (6,605)	$ 17,847	$ (15,547)	$ 166,232	$ 11,971	$ 11,033	$ 23,005	$ 189,236	$ 1,519,444	6	10	1.52%	2.03%
Q0-C	$ 82,710	$ 5,450	$ 36,781	$ 48,063	$ (7,174)	$ 14,877	$ (15,547)	$ 165,160	$ 10,213	$ 11,033	$ 21,247	$ 186,407	$ 1,496,725	1	3	**0.00%**	0.50%
Q0-D	$ 76,954	$ 4,754	$ 36,165	$ 47,660	$ (4,556)	$ 24,256	$ (15,546)	$ 169,687	$ 6,277	$ 11,033	$ 17,311	$ 186,998	$ 1,501,474	2	4	0.32%	0.82%
Q0-E	$ 79,083	$ 4,841	$ 36,589	$ 48,134	$ (5,544)	$ 19,852	$ (15,547)	$ 167,409	$ 9,264	$ 11,033	$ 20,298	$ 187,706	$ 1,507,161	5	8	0.70%	1.21%
Q0-F	$ 77,342	$ 4,760	$ 36,230	$ 47,676	$ (4,640)	$ 23,475	$ (15,546)	$ 169,297	$ 6,788	$ 11,033	$ 17,821	$ 187,118	$ 1,502,435	3	5	0.38%	0.89%
Q1 Retires after 2017																	
Q1-A	$ 77,628	$ 5,095	$ 38,986	$ 52,883	$ (6,877)	$ 16,568	$ (15,546)	$ 168,737	$ 4,054	$ 14,496	$ 18,550	$ 187,286	$ 1,503,788	3	6	0.98%	0.98%
Q1-B	$ 78,825	$ 5,120	$ 38,968	$ 53,070	$ (7,213)	$ 14,232	$ (15,547)	$ 167,454	$ 3,521	$ 14,496	$ 18,016	$ 185,470	$ 1,489,207	1	1	**0.00%**	**0.00%**
Q1-C	$ 77,140	$ 5,015	$ 39,122	$ 52,706	$ (6,392)	$ 16,445	$ (15,546)	$ 168,490	$ 3,140	$ 14,496	$ 17,635	$ 186,125	$ 1,494,463	2	2	0.35%	0.35%
Q1-D	$ 80,283	$ 5,808	$ 39,262	$ 52,823	$ (8,200)	$ 12,197	$ (15,546)	$ 166,627	$ 7,232	$ 14,496	$ 21,727	$ 188,354	$ 1,512,359	4	9	1.55%	1.55%

No Economy Purchases

	Levelized Annual Production Cost								Levelized Annual Capital Cost			Levelized	Cumulative	Rank	Rank	%	
							Nearman	Net	Unit Additions	AQC	*Total*	Total	Present	within	within	Difference	
	Fuel	O&M		*Emission*	Economy	Economy	Participant	Production	Capital	Capital	*Capital*	System	Worth	Cat-	All	From Least	
Base Plans	Cost[1]	Variable	Fixed	*Costs*	Sales	Purchase	Sales	Cost	Cost	Cost	*Cost*	Cost	Cost	egory	Plans	Cost Plan	
	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)			Category	All Plans
Q1 Retires in 2011																	
Q0-A	$ 108,434	$ 6,591	$ 36,415	$ 9,880	$ (7,718)	$ -	$ (15,547)	$ 138,055	$ 9,109	$ 11,033	$ 20,143	$ 158,197	$ 1,270,223	3	7	0.89%	4.14%
Q0-B	$ 105,665	$ 6,635	$ 36,755	$ 9,833	$ (8,065)	$ -	$ (15,548)	$ 135,275	$ 11,971	$ 11,033	$ 23,005	$ 158,280	$ 1,270,884	4	8	0.95%	4.20%
Q0-C	$ 105,609	$ 6,394	$ 36,781	$ 9,916	$ (7,603)	$ -	$ (15,548)	$ 135,548	$ 10,213	$ 11,033	$ 21,247	$ 156,795	$ 1,258,961	1	5	**0.00%**	3.22%
Q0-D	$ 112,143	$ 5,937	$ 36,165	$ 10,134	$ (6,072)	$ -	$ (15,548)	$ 142,759	$ 6,277	$ 11,033	$ 17,311	$ 160,070	$ 1,285,260	6	10	2.09%	5.38%
Q0-E	$ 106,647	$ 6,050	$ 36,589	$ 10,038	$ (6,271)	$ -	$ (15,548)	$ 137,504	$ 9,264	$ 11,033	$ 20,298	$ 157,802	$ 1,267,049	2	6	0.64%	3.88%
Q0-F	$ 110,784	$ 5,934	$ 36,230	$ 10,142	$ (5,945)	$ -	$ (15,548)	$ 141,598	$ 6,788	$ 11,033	$ 17,821	$ 159,418	$ 1,280,028	5	9	1.67%	4.95%
Q1 Retires after 2017																	
Q1-A	$ 103,498	$ 5,915	$ 38,986	$ 11,185	$ (7,986)	$ -	$ (15,548)	$ 136,051	$ 4,054	$ 14,496	$ 18,550	$ 154,600	$ 1,241,340	4	4	1.77%	1.77%
Q1-B	$ 100,875	$ 6,056	$ 38,968	$ 11,065	$ (7,527)	$ -	$ (15,548)	$ 133,889	$ 3,521	$ 14,496	$ 18,016	$ 151,905	$ 1,219,698	1	1	**0.00%**	**0.00%**
Q1-C	$ 101,440	$ 6,046	$ 39,122	$ 11,053	$ (6,711)	$ -	$ (15,548)	$ 135,403	$ 3,140	$ 14,496	$ 17,635	$ 153,038	$ 1,228,795	2	2	0.75%	0.75%
Q1-D	$ 99,203	$ 6,593	$ 39,262	$ 10,889	$ (8,768)	$ -	$ (15,548)	$ 131,631	$ 7,232	$ 14,496	$ 21,727	$ 153,358	$ 1,231,366	3	3	0.96%	0.96%

Appendix D
Site Selection Scoring Criteria

Appendix D
Site Selection Scoring Criteria

This appendix defines the environmental and technical evaluation criteria assigned to the various scores. Best professional judgment was used to select the relative desirability of the criteria. All scoring was based on current conditions at the time of this study.

Socioeconomics

Noise Impacts

Definition: The impacts of increased noise levels resulting from the operation of the proposed plant on nearby residences, sensitive facilities, and population centers (receptors).

Score	Criteria
10	No receptors within 2 miles of the site.
8	One or two receptors within 2 miles of the site.
6	Three to five receptors within 2 miles of the site.
4	One to five receptors within 1 mile of the site.
1	More than five receptors within 1 mile of the site.

Impact of Project Traffic

Definition: The impact of increased traffic related to project construction and operation on existing roads and traffic patterns in site area.

Score	Criteria
10	Minimal increase in total traffic.
7	Moderate increase in total traffic.
4	Major increase in total traffic.

Impact on Sensitive Areas

Definition: Parks; state or federal forests; monuments; and recreational, wildlife, or wilderness areas are considered sensitive areas.

Scoring: Sites will be scored by assessing the potential visibility/aesthetic, noise, and air quality impacts of project operation on sensitive areas in the professional judgment of the evaluator. Sites with no anticipated impact or minimum impact will be assigned the score of 10, with the other sites given relative scores.

Land Use

Land Ownership

Definition:	Private or public property.
Score	**Criteria**
10	Private or BPU ownership.
7	Municipal or Wyandotte County ownership.
5	State ownership.
3	Federal ownership.
1	Multiple owners.

Site Location

Definition:	Location relative to BPU electric facility.
Score	**Criteria**
10	Site at existing power plant.
5	Site at existing or new substation.

Land Use Compatibility

Definition:	Site compatibility with current zoning and local land use.
Score	**Criteria**
10	Compatible with current zoning and land use.
7	Compatible with future zoning and land use.
3	Rezoning required.

Air Quality

Definition:	Probability of air construction permitting requirements.
Score	**Permit required**
10	Minor permit required.
5	Major permit required.

Site Development

Ease of Development

Definition:	Based upon site reconnaissance and aerial photographs, the ease of development was evaluated. Considerations included current site area, topography, and access.
Score	**Ease of Development**
10	Existing site with adequate area, relatively flat topography, and good access.

Score	Ease of Development
5	Existing site with adequate area that requires some demolition or relocation, relatively flat topography, and good access.
1	New site with adequate area that will require complete development, or has un-level topography, and requires new access means to be installed.

Availability of Common Facilities

Definition: If existing common facilities are available, site development is greatly reduced. Conversely if all new facilities are required to be developed as part of the unit installation, site development is greatly increased. Common facilities include water supply systems, water treatment (demineralizer) systems, wastewater collection and treatment systems, and transmission substation and interconnection facilities.

Score	Availability of Common Facilities
10	Existing site with adequate existing common facilities for water, wastewater, transmission, and access.
5	Existing site with some existing common facilities.
1	New site where all facilities will need to be developed.

Differential Site Development Costs

Some of the principal site comparisons during the site selection process are on the basis of estimated costs, such as capital costs to prepare the site (cut/fill), install facilities, transmission facilities, and utilities pipelines. The method used to score each cost-based comparison will be to assign the point value of 10 to the lowest costs, the value of 1 to the highest cost site, and award intermediate scores on the basis of site costs.

Project costs can be separated into two categories: the power block capital costs and site development costs. The total power block capital cost for each site was assumed to be the same at each candidate site. However, each site has specific characteristics that can influence the total site development costs for the proposed power generation facilities at that particular site location. The following paragraphs explain the portions of the site development costs that are not included in the power block capital costs.

Natural Gas Pipeline

Natural gas is required as the main fuel for the new power generating unit. Between 20 and 50 mcf per hour of natural gas is required for a simple cycle unit and between 40 and 100 mcf per hour of natural gas is required for a combined cycle unit.

This quantity of natural gas is available currently on an interruptible basis from the main pipeline systems described in Section 16.1. A 4 inch to 12 inch line, depending on supply pressure, is required for the natural gas supply to a simple cycle unit and 6 inch to 16 inch line would be required for the natural gas supply to a combined cycle unit. In addition, gas compression may be required depending on the natural gas supply pressure and the type of combustion turbine selected. The cost of the natural gas supply line to each site is highly dependent on numerous factors. The length and route of the line would be two of the primary factors in the cost. The estimated cost of a 12 inch natural gas line is $1,600,000 per mile. The capital cost is highly dependent on the length of pipeline required, local terrain and surface conditions, subsurface conditions, proximity to structures, roads and railroad crossings, and numerous other factors.

Water Supply System and Pipeline

Water is required for potable, cooling, and service applications. Approximately 60 to 110 gpm (0.09 to 0.16 mgd) is needed for a simple cycle unit installation and 630 to 1,700 gpm (0.9 to 2.5 mgd) for a combined cycle unit installation. For the purpose of this study, it has been assumed this quantity of water can be furnished from existing BPU municipal water supplies. A minimum 6 inch line could be used for the water supply to a simple cycle unit installation and 12 inch line could be used for the water supply for a combined cycle unit installation. The cost for the water supply pipeline is highly dependent on numerous factors. The length and route of the line would be two of the primary factors in the cost. According to BPU the estimated cost of a 12 inch water supply line is $500,000 per mile and for a 6 inch water line is $400,000 per mile. The capital cost is highly dependent on the length of pipeline required, local terrain and surface conditions, subsurface conditions, proximity to structures, roads and railroad crossings, and numerous other factors.

Sewer Pipeline (Wastewater Discharge System)

A wastewater discharge system is required for the installations. Approximately 16 to 27 gpm (0.009 to .004 mgd) will be discharged from a simple cycle unit installation and 160 to 420 gpm (0.2 to 0.6 mgd) for a combined cycle unit installation. For the purpose of this study, it has been assumed the wastewater can be discharged to existing power plant wastewater facilities or to the municipal sewer system. A minimum 3 or 4 inch line is required for the wastewater discharge from a simple cycle unit installation and 8 or 10 inch line is required for a combined cycle unit installation. The cost for the sewer pipeline is highly dependent on numerous factors. The length and route of the line would be two of the primary factors in the cost. The estimated cost for a 4 inch wastewater line is $450,000 per mile. The capital cost is highly dependent on the length of pipeline required, local terrain and surface conditions, subsurface conditions, proximity to structures, roads and railroad crossings, and numerous other factors.

Access Road

It is assumed that the access road to the site would be asphalt surfaced. The unit cost of new roadway or significant road improvements is $170,000 per mile, based on a 24 foot wide access road with a 10 inch aggregate base and 3 inches of asphalt.

Transmission Interconnection

It has been assumed, since all sites are at existing power generating stations or at existing or new substations, that the costs of the actual transmission interconnection would be similar. Therefore, no differential site development costs were included for transmission interconnections. Also, since the actual site location has not been selected, BPU has not determined if any transmission system upgrades would be necessary with installation of the new generating unit at any particular site. After the site selection is completed and the unit type and size selected, BPU may want to determine if substantial costs are involved with the preferred site.

Substation Improvements

The incremental site substation costs have been estimated to include normal substation upgrades typically associated with installation of a new simple cycle or combined cycle unit. For the purpose of comparisons, the cost of the upgrades has been estimated at $2,000,000 for sites with existing substations and $1,000,000 for new planned substations where the modifications required could be part of the original substation design.

Land Acquisition

The sites were assumed to cost the same per acre for this analysis, due to limits in available estimated land values ($5,000 per acre). For the purposes of this comparison, it will be assumed that 10 acres of land will be required for a combined cycle unit and 4 acres of land will be required for a simple cycle unit. Additional land will only be required at substation sites as there is adequate land available at the existing power generation sites. The actual cost of land will vary at each site in reality.

Site Preparation

Site preparation which includes the work necessary to prepare the site for construction activities is necessary. Existing power generation sites will have little to no site preparation costs. Future planned or existing substation sites will require site clearing, grubbing, and leveling to prepare the site for construction. Site preparation has been estimated to be $10,000 per acre. For the purposes of this comparison, it will be assumed that 10 acres of land will be required for a combined cycle unit and 4 acres of land will be required for a simple cycle unit.

Other Site Development Costs

Costs have been included as required for natural gas compression, demineralizer system, demineralized water storage tank, and fuel oil storage tank.

Availability of Personnel (O&M) and Security

Operation & Maintenance Personnel Considerations

Operations and maintenance of the new unit will be performed by BPU's power plant staff. If the new unit were located at an existing operating power plant site such that operations and maintenance personnel and equipment are available fewer additional staff would be required. Remote operation of simple cycle units is common in the industry and with the proper training, monitoring and control equipment, and routine maintenance, operations should not be a problem. Routine and necessary maintenance could be provided by existing staff on a scheduled basis, but equipment and materials would have to be transported to the site as required. A combined cycle unit installation will need to be staffed with full time operations and maintenance personnel. If the combined cycle unit is installed at an existing operating site, operations and maintenance staff and equipment could be shared and a minimum increase in staff levels would be required. If the combined cycle unit is installed remotely from an existing operating facility, new dedicated operations and maintenance staff and equipment would need to be added to the staff.

Score	Criteria
10	Installation at a currently operating plant.
5	Installation at a partially staffed site.
1	Installation at a remote site not currently staffed.

Security Issues

Security and the ability to provide security for the new installation is an important consideration in the site selection. Safety of the public is of primary importance, with various factors such as vandalism and theft and their impact on BPU costs and ability to run the unit at the most opportune times should all be considered. New units installed on existing plant sites that already have full time security will not require additional and sometimes costly security systems. Remote, normally unattended sites would need to be equipped with state-of-the art security systems which provide both deterrents and remote monitoring to limit public access, vandalism, and theft.

Score	Criteria
10	Installation at currently operating plant.
1	Installation at a remote unattended site.

Appendix E
Comparison of Phase II Revenue Requirements

Q0-D: Q1 Retires in 2011, Add GE 7EA in 2011 and LM6000 in 2013 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	55,650	9	01/01/2011	73,684	7,752
LM6000 SCCT	45,670	10	01/01/2013	68,253	7,180

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	Plant O&M & contract purchs inclding trnsmsn[6]: Variable[2] ($1,000)	Plant O&M & contract purchs inclding trnsmsn[6]: Fixed[3] ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	Capital Cost: AQC retrofit Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,405	$108,852	$0	$0	$0	$108,852	$201,783
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,447	$6,162	$117,390	$0	$5,905	$5,905	$123,295	$313,084
2011	2,635	$76,490	$3,877	$39,361	$6,022	-$2,620	$22,902	-$17,544	$6,985	$135,474	$7,752	$5,905	$13,657	$149,131	$440,993
2012	2,644	$78,340	$4,108	$40,488	$20,870	-$3,081	$32,241	-$16,725	$10,063	$166,304	$7,752	$5,905	$13,657	$179,961	$587,646
2013	2,669	$80,408	$6,492	$44,323	$24,141	-$3,361	$25,384	-$19,057	$11,480	$169,811	$14,932	$33,960	$48,892	$218,703	$756,979
2014	2,697	$86,792	$6,564	$45,520	$29,841	-$3,443	$26,560	-$19,573	$13,738	$186,000	$14,932	$33,960	$48,892	$234,892	$929,776
2015	2,721	$91,205	$6,612	$46,607	$32,879	-$4,366	$28,878	-$20,419	$15,267	$196,662	$14,932	$33,960	$48,892	$245,554	$1,101,406
2016	2,733	$95,445	$6,787	$47,900	$36,185	-$4,341	$29,904	-$21,367	$16,717	$207,230	$14,932	$33,960	$48,892	$256,121	$1,271,492
2017	2,744	$98,913	$6,852	$49,160	$39,494	-$5,259	$32,874	-$22,243	$16,991	$216,782	$14,932	$33,960	$48,892	$265,674	$1,439,121
Levelized Cost($1000):		$78,335	$5,071	$42,192	$18,796	-$4,584	$22,874	-$18,036	$9,739	$154,388	$8,131	$16,714	$24,844	$179,232	
NPV:		$628,982	$40,719	$338,772	$150,922	-$36,806	$183,667	-$144,820	$78,200	$1,239,636	$65,285	$134,199	$199,484	$1,439,121	
Levelized Cost($/MWh):		$23.68	$1.53	$12.75	$5.68	-$1.39	$6.91	-$5.45	$2.94	$46.67	$2.46	$5.05	$7.51	$54.18	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Q0-F: Q1 Retires in 2011, Add LM6000 in 2011 and GE 7EA in 2012 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)	AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	55,650	9	01/01/2012	78,842	8,294						
LM6000 SCCT	45,670	10	01/01/2011	60,429	6,357	Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
						N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
						N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	2011

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	Plant O&M & contract purchs inclding trnsmsn[6]: Variable[2] ($1,000)	Plant O&M & contract purchs inclding trnsmsn[6]: Fixed[3] ($1,000)	*Emission Costs [4]* *($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost* *($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,405	$108,852	$0	$0	$0	$108,852	$201,783
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,447	$6,162	$117,390	$0	$5,905	$5,905	$123,295	$313,084
2011	2,635	$76,088	$3,709	$39,334	$6,027	-$2,395	$21,607	-$17,544	$6,985	$133,812	$6,357	$5,905	$12,262	$146,074	$438,371
2012	2,644	$76,920	$4,031	$41,174	$20,947	-$3,183	$30,605	-$16,725	$10,063	$163,833	$14,651	$5,905	$20,556	$184,389	$588,632
2013	2,669	$80,408	$6,492	$44,323	$24,141	-$3,361	$25,384	-$19,057	$11,480	$169,811	$14,651	$33,960	$48,611	$218,422	$757,749
2014	2,697	$86,792	$6,564	$45,520	$29,841	-$3,443	$26,560	-$19,573	$13,738	$186,000	$14,651	$33,960	$48,611	$234,611	$930,339
2015	2,721	$91,205	$6,612	$46,607	$32,879	-$4,366	$28,878	-$20,419	$15,267	$196,662	$14,651	$33,960	$48,611	$245,274	$1,101,773
2016	2,733	$95,445	$6,787	$47,900	$36,185	-$4,341	$29,904	-$21,367	$16,717	$207,230	$14,651	$33,960	$48,611	$255,841	$1,271,673
2017	2,744	$98,913	$6,852	$49,160	$39,494	-$5,259	$32,874	-$22,243	$16,991	$216,782	$14,651	$33,960	$48,611	$265,393	$1,439,125
Levelized Cost($1000):		$78,148	$5,046	$42,258	$18,805	-$4,570	$22,570	-$18,036	$9,739	$153,960	$8,560	$16,714	$25,273	$179,233	
NPV:		$627,480	$40,512	$339,308	$150,988	-$36,696	$181,223	-$144,820	$78,200	$1,236,197	$68,729	$134,199	$202,928	$1,439,125	
Levelized Cost($/MWh):		$23.62	$1.53	$12.77	$5.68	-$1.38	$6.82	-$5.45	$2.94	$46.54	$2.59	$5.05	$7.64	$54.18	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Q1-A: Add GE 7EA in 2011 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)	AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
7EA SCCT	55,650	9	01/01/2011	73,684	7,752	Q1 SCR	33,877	25	01/01/2012	43,534	7,205
						Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
						N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
						N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	

		Production Cost									Capital Cost				
			Plant O&M & contract purchs inclding trnsmsn[6]												
Year	Served Load (GWh)	Fuel Cost[1] ($1,000)	Variable[2] ($1,000)	Fixed[3] ($1,000)	*Emission Costs [4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,600	$109,047	$0	$0	$0	$109,047	$201,968
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,942	$6,884	$117,617	$0	$5,905	$5,905	$123,522	$313,475
2011	2,635	$77,955	$4,101	$43,367	$7,066	-$6,329	$11,765	-$18,039	$10,285	$130,170	$7,752	$5,905	$13,657	$143,826	$436,834
2012	2,644	$80,070	$4,826	$45,212	$24,466	-$6,936	$16,850	-$17,220	$13,428	$160,695	$7,752	$13,110	$20,861	$181,557	$584,787
2013	2,669	$83,627	$7,222	$48,667	$28,215	-$8,067	$13,317	-$23,128	$14,974	$164,827	$7,752	$41,165	$48,916	$213,743	$750,281
2014	2,697	$88,427	$7,173	$49,984	$34,620	-$7,423	$15,093	-$23,643	$17,288	$181,518	$7,752	$41,165	$48,916	$230,434	$919,798
2015	2,721	$94,836	$7,402	$51,194	$38,286	-$9,264	$14,610	-$24,487	$18,928	$191,505	$7,752	$41,165	$48,916	$240,421	$1,087,840
2016	2,733	$97,039	$7,400	$52,611	$41,659	-$9,364	$17,086	-$25,438	$20,470	$201,462	$7,752	$41,165	$48,916	$250,379	$1,254,113
2017	2,744	$99,918	$7,418	$54,002	$45,296	-$10,354	$18,963	-$26,316	$21,838	$210,767	$7,752	$41,165	$48,916	$259,683	$1,417,962
Levelized Cost($1000):		$79,655	$5,458	$45,096	$21,483	-$7,432	$14,513	-$19,971	$12,210	$151,011	$4,997	$20,589	$25,586	$176,597	
NPV:		$639,575	$43,825	$362,093	$172,493	-$59,674	$116,530	-$160,357	$98,036	$1,212,520	$40,126	$165,316	$205,442	$1,417,962	
Levelized Cost($/MWh):		$24.08	$1.65	$13.63	$6.49	-$2.25	$4.39	-$6.04	$3.69	$45.65	$1.51	$6.22	$7.73	$53.38	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Q1-B: Add LM6000 in 2011 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM6000 SCCT	45,670	10	01/01/2011	60,429	6,357

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	43,534	7,205
Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055
	36,986	12	01/01/2011	44,836	7,420

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	Plant O&M & contract purchs inclding trnsmsn[6]: Variable[2] ($1,000)	Plant O&M & contract purchs inclding trnsmsn[6]: Fixed[3] ($1,000)	*Emission Costs*[4] *($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,600	$109,047	$0	$0	$0	$109,047	$201,968
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,942	$6,884	$117,617	$0	$5,905	$5,905	$123,522	$313,475
2011	2,635	$77,772	$3,986	$43,990	$7,073	-$6,398	$10,787	-$18,984	$10,285	$128,510	$6,357	$13,325	$19,683	$148,192	$440,579
2012	2,644	$79,915	$4,732	$45,847	$24,419	-$7,080	$15,884	-$18,166	$13,428	$158,980	$6,357	$20,530	$26,887	$185,867	$592,044
2013	2,669	$83,366	$7,164	$49,315	$28,190	-$7,942	$12,014	-$24,074	$14,974	$163,008	$6,357	$48,585	$54,942	$217,950	$760,796
2014	2,697	$89,570	$7,202	$50,643	$34,732	-$8,384	$12,981	-$24,589	$17,288	$179,444	$6,357	$48,585	$54,942	$234,386	$933,220
2015	2,721	$94,409	$7,339	$51,864	$38,206	-$9,029	$13,407	-$25,436	$18,928	$189,688	$6,357	$48,585	$54,942	$244,630	$1,104,204
2016	2,733	$97,279	$7,386	$53,293	$41,620	-$9,290	$14,865	-$26,386	$20,470	$199,238	$6,357	$48,585	$54,942	$254,180	$1,273,001
2017	2,744	$100,783	$7,445	$54,695	$45,323	-$10,889	$16,402	-$27,259	$21,838	$208,338	$6,357	$48,585	$54,942	$263,281	$1,439,121
Levelized Cost($1000):		$79,750	$5,429	$45,519	$21,479	-$7,545	$13,502	-$20,581	$12,210	$149,761	$4,098	$25,373	$29,471	$179,232	
NPV:		$640,337	$43,591	$365,491	$172,459	-$60,585	$108,411	-$165,255	$98,036	$1,202,485	$32,908	$203,728	$236,636	$1,439,121	
Levelized Cost($/MWh):		$24.11	$1.64	$13.76	$6.49	-$2.28	$4.08	-$6.22	$3.69	$45.27	$1.24	$7.67	$8.91	$54.18	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Q1-C: Add LM2500s in 2011 and 2015 with SCR

Financing Parameters	
Bond Interest Rate:	5.25%
Bond Issue Fee:	2.00%
Working Capital:	60 Days
Insurance	1.0%
Annual Insurance escalation	1.5%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate	variable
Base Year for $	2008

Financial Parameters	
Owner's Cost (% of EPC)	9%
Interest During Construction:	5.25%
Combustion Turbine Fixed Charge Rate:	10.52%
Combined Cycle Fixed Charge Rate:	9.36%
Existing Plant O&M Capital FCR:	16.55%
AQC Retrofit Fixed Charge Rate:	16.55%

Generation Additions

Unit	2008 EPC Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
LM2500 SCCT	30,600	10	01/01/2011	40,489	4,259
LM2500 SCCT	30,600	10	01/01/2015	49,012	5,156

AQC Upgrade	2008 Capital Cost ($1,000)	Construction Period (months)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
Q1 SCR	33,877	25	01/01/2012	43,534	7,205
Q2 LNB and OFA	10,701	2	01/01/2010	12,203	2,020
N1 LNB and OFA	20,586	2	01/01/2010	23,476	3,885
N1 FGD, Fabric Filter, & Landfill	123,283	25	01/01/2013	169,516	28,055

Unit	Retirement Year	Unit	Retirement Year
CT#1	2015	Quindaro #1	

Year	Served Load (GWh)	Production Cost: Fuel Cost[1] ($1,000)	Plant O&M & contract purchs inclding trnsmsn[6]: Variable[2] ($1,000)	Plant O&M & contract purchs inclding trnsmsn[6]: Fixed[3] ($1,000)	*Emission Costs[4] ($1,000)*	Economy Sales ($1000)	Economy Purchase[5] ($1000)	Nearman Participant Sales ($1,000)	Existing Plant O&M Capital Cost ($1,000)	Net Production Cost ($1,000)	Capital Cost: Unit Additions Capital Cost ($1,000)	AQC retrofit Capital Cost ($1,000)	*Total Capital Cost ($1,000)*	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2008	2,555	$63,797	$3,565	$34,478	$4,894	-$6,945	$11,374	-$15,575	$2,773	$98,361	$0	$0	$0	$98,361	$98,361
2009	2,570	$63,118	$3,807	$37,754	$5,624	-$6,492	$15,445	-$14,810	$4,600	$109,047	$0	$0	$0	$109,047	$201,968
2010	2,594	$66,603	$3,940	$42,605	$6,578	-$5,037	$12,987	-$16,942	$6,884	$117,617	$0	$5,905	$5,905	$123,522	$313,475
2011	2,635	$77,724	$3,963	$43,938	$7,072	-$5,837	$11,497	-$18,039	$10,285	$130,604	$4,259	$5,905	$10,164	$140,769	$434,212
2012	2,644	$79,914	$4,685	$45,794	$24,345	-$6,374	$16,715	-$17,220	$13,428	$161,286	$4,259	$13,110	$17,369	$178,655	$579,800
2013	2,669	$83,248	$7,118	$49,260	$28,118	-$7,516	$13,065	-$23,128	$14,974	$165,140	$4,259	$41,165	$45,424	$210,564	$742,833
2014	2,697	$88,477	$7,102	$50,587	$34,514	-$7,243	$14,832	-$23,643	$17,288	$181,912	$4,259	$41,165	$45,424	$227,336	$910,071
2015	2,721	$94,066	$7,305	$53,193	$38,135	-$8,459	$14,444	-$24,490	$18,928	$193,121	$9,416	$41,165	$50,580	$243,702	$1,080,406
2016	2,733	$95,954	$7,280	$54,654	$41,419	-$8,472	$17,057	-$25,442	$20,470	$202,921	$9,416	$41,165	$50,580	$253,501	$1,248,752
2017	2,744	$98,824	$7,306	$56,085	$45,067	-$9,272	$18,681	-$26,314	$21,838	$212,216	$9,416	$41,165	$50,580	$262,796	$1,414,566
Levelized Cost($1000):		$79,339	$5,385	$45,836	$21,401	-$7,024	$14,384	-$19,972	$12,210	$151,559	$4,027	$20,589	$24,615	$176,174	
NPV:		$637,044	$43,240	$368,030	$171,836	-$56,396	$115,491	-$160,361	$98,036	$1,216,920	$32,330	$165,316	$197,646	$1,414,566	
Levelized Cost($/MWh):		$23.98	$1.63	$13.86	$6.47	-$2.12	$4.35	-$6.04	$3.69	$45.82	$1.22	$6.22	$7.44	$53.26	

Notes:
(1) Fuel Cost column includes fuel costs (excluding start-up fuel costs on steam units and existing Quindaro CTs) and emergency purchases assumed to cost $80/MWh during non-summer months and $186/MWh during summer months ($2008). Also included are SWPA and WAPA hydro energy costs, Empire energy purchase, and Smoky Hill Wind farm energy purchase.
(2) VOM column includes unit start-up cost (including start-up fuel costs on steam units and existing Quindaro CTs) and includes additional variable costs associated with AQC retrofits. Also included are the variable transmission service costs for the Empire purchase, the SWPA and WAPA hydro purchases, and the Smoky Hills Wind Farm.
(3) FOM column includes capacity and fixed transmission costs associated with the Empire purchase, demand charge and fixed transmission cost for hydro purchases, and transmission demand charge associated with Smoky Hills Wind Farm.
(4) Emissions costs is composed of SO2 allowance and Carbon tax costs. Carbon tax begins in 2012.
(5) Discrete scheduled maintenance events on existing units through 2013 causes nonuniformity of economy purchases and sales. Average maintenance rates are assumed beginning in 2014.
(6) Charges associated with purchase power contracts and start-up fuels are included in the ERC.

Appendix F
Combustion Turbine Permit List

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected / Typical Review Time	Required for SCCT	Required for CCCT	Comments/Issues
FEDERAL							
COE	Section 10 Permit	Construction activities in navigable waters of the US.	Construction	3 - 9 months for individual 1 - 2 months for nationwide	MAYBE	MAYBE	Typically required for new construction of intake and outfall structures, barge facilities, or loading/unloading docks. *RE: Intake - No new intake required. Assume raw water will be supplied via BPU city water supply, i.e. from horizontal collector wells. See related Water Rights Extension Permit.* *Re: Outfall - Consider existing discharge structure condition to determine whether modification or repairs are necessary to discharge wastewater from new CT.*
COE	Section 404 Permit / NEPA Review	Discharge of dredge or fill material into waters of the US, including jurisdictional wetlands.	Construction	3 - 9 months for individual 1 - 2 months for nationwide	MAYBE	MAYBE	A nationwide permit may be authorized for utility line activities within COE wetlands. An Individual Permit will likely be required for impacts to wetlands greater than .50 acre. *Recommend confirming with the COE that the portion of the Nearman Creek Power Station enclosed within the flood levee is not within COE jurisdiction. The potential for impacting wetlands outside of the levee should be determined.*
DOE	Alternate Fuels Capability Certification	Baseload facility using natural gas.	Operation	Self-certification upon filing Permanent exemption 3-6 months	NO	YES	*SCCT will be a peaking load facility.*
EPA	Title IV Acid Rain Permit	Release of SO_2 from new units > 25 MW.	Operation	24 months	YES	YES	Application must be submitted 24-months prior to operation. *The new unit must submit a revised Phase II EPA Title IV Acid Rain Permit application. This will become part of the BPU Title V Operating Permit.*
EPA	CEMs Monitoring Plan	Indicate how the CEMs will appropriately measure air emissions.	Operation	6 months	YES	YES	Required by Title IV Acid Rain Permit.
EPA	SPCC Plan	Total onsite storage of oil > 1,320 gallons. Only containers of oil with a capacity of 55 gallons or greater are counted.	Construction / Operation	N/A	YES	YES	See also EPA's proposed changes of 10/01/07. *BPU will need to develop and implement an SPCC plan for construction-specific activities. Updates to existing operational plan will include new site arrangement and oil storage quantities.*
EPA	Risk Management Plan (RMP)	Potential accidental releases of hazardous chemicals that are used or stored onsite in greater than threshold quantities.	Post-Operation	3 - 4 months	NO	MAYBE	An RMP must be submitted no later than the date on which a regulated substance is first present above a threshold quantity in a process. Substances regulated under 40 CFR 68 include aqueous ammonia, 20% solution (20,000 lbs threshold) and hydrazine (15,000 lbs threshold). *BPU currently maintains an RMP for chlorine used in cooling tower. Additional ammonia storage required for CCCT air emissions control equipment may trigger RMP for ammonia.*
EPA	Toxic Release Inventory under EPCRA/KEPCRA	TRI Reporting.	Construction / Operation	N/A	YES	YES	Reporting requirements triggered by storage/ handling of toxic chemicals (EPCRA Section 313) above threshold limits; applicable to entire facility.
FAA	Notice of Proposed Construction or Alteration	Construction of tall objects, such as exhaust stacks and construction cranes, that may affect navigable airspace. Objects exceeding 200' or are within 20,000' of an airport typically require notice to FAA.	Construction	3 months	MAYBE	MAYBE	FAA may recommend lighting or marking of tall objects. Even if height or distance threshold is not triggered, Black & Veatch recommends courtesy notice. *Stack height for SCCT is estimated at 100', for CCCT at 170'. A preliminary check of the surrounding airfields indicates that the nearest public-use / military-use airports to the Nearman Creek Power Station is the Charles B. Wheeler Downtown Airport (KMKC), approximately 6 miles east.*
USFWS	Endangered Species Act Section 7 Consultation	Confirmation of no impacts to threatened or endangered species.	Construction	1 - 2 months, initial consultation letter	YES	YES	*USFWS will review project to determine whether activities will impact bald eagle and its habitat, or any listed species or critical habitat.*

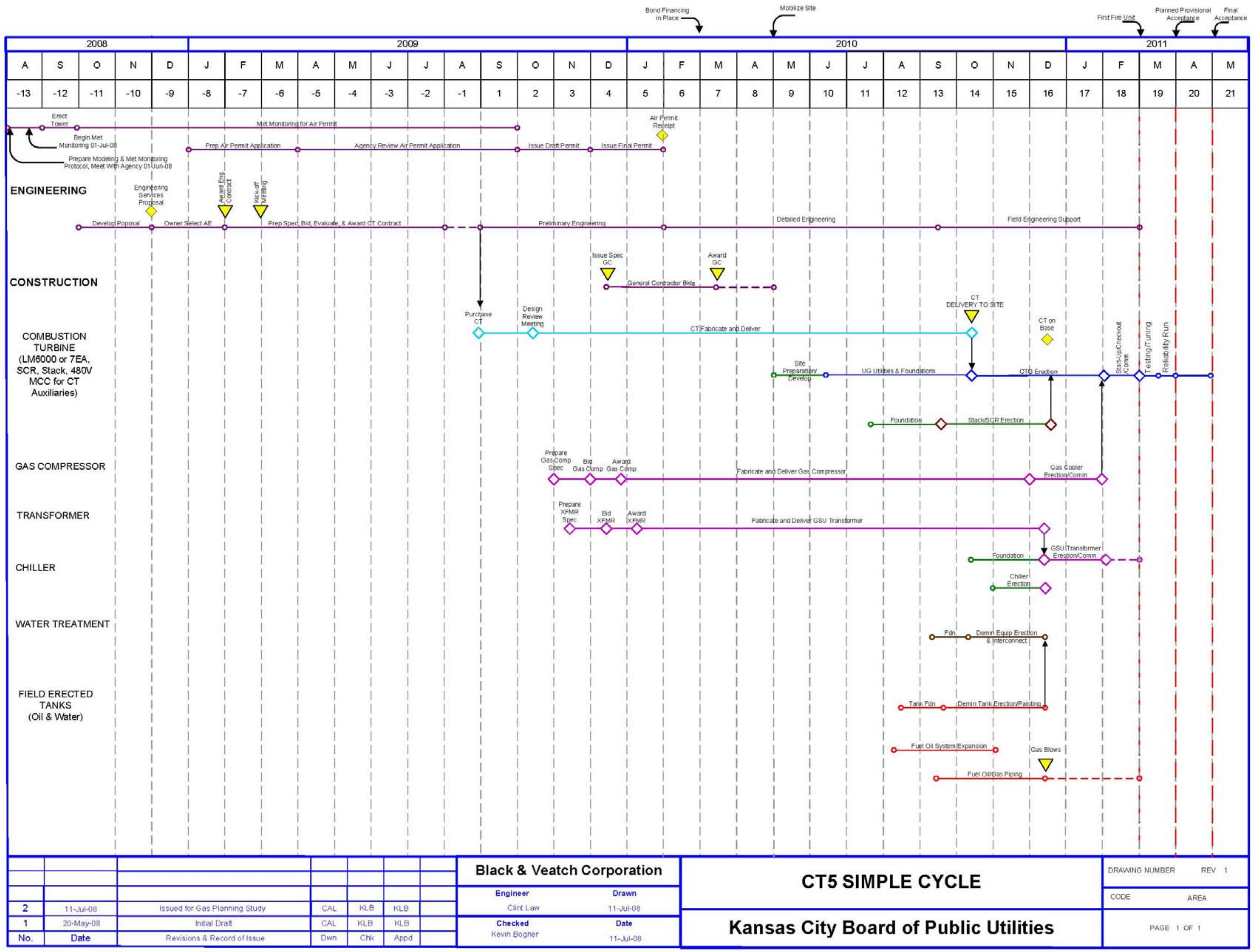
Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected / Typical Review Time	Required for SCCT	Required for CCCT	Comments/Issues
STATE							
KDHE	NPDES General Storm Water Permit for Construction	Discharge of storm water runoff during construction activities affecting ≥1 acres.	Construction	2 months, NOI to be submitted at least 60 days before starting construction	YES	YES	The KDHE prefers that a complete application be submitted during the design phase of the project. A complete application consists of a NOI, a summary of the SWPPP, an area map, a site plan, and the first annual permit fee.
KDHE	Construction Storm Water Pollution Prevention Plan	To design, implement, manage, and maintain Best Management Practices to reduce the amount of pollutants in storm water discharges.	Construction	60 days, see above plan	YES	YES	The plan must be developed and implemented within one year of the effective date of the permit.
KDHE	NPDES Individual Permit Modification	Discharge of industrial wastewater and storm water runoff during operation of facility to surface waters.	Operation	6 - 9 months	MAYBE	YES	*The addition of a CCCT unit will require modification of the existing NPDES permit.* *The addition of an SCCT is not expected to result in a wastewater discharge to surface waters, as wastewaters will be collected and hauled off by a contractor. However; for major plant modifications, KDHE recommends a preliminary meeting with the Bureau of Water and permittee to understand the proposal and determine whether or not a permit revision is necessary.*
KDHE	Operational Storm Water Pollution Prevention Plan Modification	To design, implement, manage, and maintain Best Management Practices to reduce the amount of pollutants in storm water discharges.	Operation	6 - 9 months	YES	YES	*Update existing plan to include new unit information.*
KDHE	CWA 316(b) Review and Approval	The location, design, construction and capacity of cooling water intake structures.	Operation	N/A	NO	NO	*Water for the CT unit will be provided by municipal water supply, no new cooling water intake will be required.*
KDHE	NPDES Hydrostatic Test Water Discharge Permit	Hydrostatic test discharges from new pipelines and storage tanks.	Construction	Submit NOI 60 days prior to activity	LIKELY	LIKELY	A separate permit is required for each diversion point.
KDHE	Section 401 Water Quality Certification	Impacts to state waters resulting from federal actions.	Construction	3 - 4 months	MAYBE	MAYBE	See also Section 404 COE permits.
KDHE	Industrial Waste Landfill Construction Permit	The Construction of a solid waste processing facility or a solid waste disposal area of a solid waste management system.	Construction	Hydrogeologic studies and approval 1.5 to 2.5 years. Permit application 9 months after approvals of hydrogeologic studies	NO	NO	
KDHE	AST System Permitting and Registration	Storage of flammable and combustible liquids.	Construction	2 - 3 months	NO	NO	Tanks < 660 gallons are exempt. KSFM approval required in advance of KDHE approval. *Existing fuel oil tanks at BPU Nearman Creek are sufficient to provide for 3 days storage.*
KSFM	AST System Approval	Storage of flammable and combustible liquids.	Construction	2 - 3 months	NO	NO	KSFM will ensure that tanks meet applicable fire codes.
KDWP	Threatened and Endangered Species Evaluation	Protection of endangered species.	Construction	1 - 2 months, initial consultation letter	YES	YES	An action permit may be required, depending upon activities involving the land fill. An action permit application must be submitted no fewer than 90 days before proposed starting date. *KDWP will review project to determine whether activities will impact bald eagle and its habitat, or any listed species or critical habitat.*
KSDA	Floodplain Fill Approval	Activities affecting floodplains.	Construction	3 - 4 months	LIKELY	LIKELY	*Previous agency discussion indicates a permit will be required, even for activities within the levee. See also local permits, Floodplain Certificate.*
KSDA	Water Rights Extension / Change of Use	The appropriate of the right to lawfully divert and use water.	Construction	3 - 4 months	MAYBE	MAYBE	*Municipal city water will be used for CT unit cooling and service requirements. If source of water is from raw water supply, a change in the use of the water (from potable to industrial) may require a modification to BPU's Water Rights Permit.*

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected / Typical Review Time	Required for SCCT	Required for CCCT	Comments/Issues
KSDA	Dewatering Permit	Ground water intrusion.	Construction	60 days	LIKELY	LIKELY	Required for temporary appropriation of state waters resulting from construction dewatering activities. *Likelihood of dewatering activities will depend on location of construction activities, time of year, water level in the Missouri River, and amount of rainfall received.*
KSDA	Stream Obstruction General Permit	Pipeline crossing of stream.	Construction	3 - 4 months	MAYBE	MAYBE	Typically required for new construction of intake and outfall structures, barge facilities, or loading/unloading docks. *This permit list assumes no activities in the Missouri River will be required for construction or operation of a combustion turbine unit. Construction activities impacting Nearman Creek or small tributaries may require permit.*
KSHS	Historical/Archeological Review	Activities that could potentially affect archeological or historical resources.	Construction	1 - 2 months for initial consultation letter.	YES	YES	A SHPO investigation of a project must begin within 30 days following notification of project.
LOCAL							
UG - DAQ	PSD/State Air Permit to Construct	Construction of air pollution control equipment and emission sources.	Construction	8 - 24 months	YES	YES	***Project may require 12 months of meteorological monitoring.*** *Permit may be issued by KDHE.*
UG - DAQ	Title V Operating Permit, Compliance Assurance Monitoring (CAM) Plan	Operation of air pollutant emission sources.	Post-Operation	9 - 12 months	YES	YES	*BPU will be required to modify its Title V permit to include CT-5 emissions no later than 12 months after the Project commences operation. Permit may be issued by KDHE.*
UG - DUP	Conformance with Comprehensive Plan	Required for construction of public utility.	Construction	2 months	YES	YES	
UG - DUP	Development Review / Zoning Conformance Review	Required for new developments in Kansas City, Kansas and Wyandotte County.	Construction	80 days minimum	YES	YES	*BPU Nearman Creek is zoned R-1, Residential Single Family District. BPU facilities are listed as Permitted Uses within this district, so no special use permit or change in zoning will be required.*
UG - DUP	Building Permits	Construction of foundations, electrical wiring, plumbing, etc.	Construction	1 month, each	YES	YES	
UG - DUP	Certificate of Occupancy	Commercial operation of facility.	Operation	1 - 2 months	YES	YES	
UG - DUP	Land Use Permit	Improvement of open, vacant or unimproved land.	Construction	80 days minimum	NOT LIKELY	NOT LIKELY	
UG - DUP	Landfill Siting Approval	60-90 days	Construction	1 - 2 months	NO	NO	
UG - DUP	Noise Limit Approval	Construction and operation of facility.	Construction / Operation	80 days minimum	YES	YES	
UG - DUP	Floodplain Certificate	Construction in floodplains.	Construction	80 days minimum	MAYBE	MAYBE	See also KSDA Floodplain Fill Approval.
UG - DPW	ROW Permit - Driveway Culvert / Driveway	New entrance road, haul road.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for new access road.*
UG - DPW	ROW Permit - Soil Hauling	Excavation activities.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for construction activities.*
UG - DPW	ROW Permit - Site Excavation	Excavation activities.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for construction activities.*
UG - DPW	ROW Permit - Oversize/Overweight Load	Equipment loads, excavation activities.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for construction activities.*
UG - DPW	ROW Permit - Land Disturbance	Excavation activities.	Construction	1 - 2 months	MAYBE	MAYBE	*May be required for construction activities*
UG - DPW	Traffic Control Plan Approval	Construction affecting more than 500 LF of ROW	Construction	1 - 2 months	NOT LIKELY	NOT LIKELY	The construction of the right-of-way requires the submittal of a traffic control plan and erosion control plan.
UG - DPW	Erosion Control Plan approval	Control of pollutants in storm water runoff.	Construction	1 - 2 months	YES	YES	See also KDHE Construction Storm Water Pollution Prevention Plan (SWPPP)

Agency	Permit/ Approval	Regulated Activity	Required Project Phase	Expected / Typical Review Time	Required for SCCT	Required for CCCT	Comments/Issues
UG - DPW	Fence Permit	The construction of any fence within the city.	Construction / Operation	1 - 2 months	NOT LIKELY	NOT LIKELY	It is unlawful for any person to construct or substantially replace any fence within the city unless a permit to do so is first obtained from the building official. *BPU Nearman Creek is currently surrounded by a security fence.*
UG-HD	Permit and License to Operate Landfill		Operation	1 - 2 months	NO	NO	
UG - FD	Chemical Storage and Fire Inspection	Installation of fire protection system.	Construction	1 - 2 months	YES	YES	
UP	Pipeline and ROW Approval	Activities within the established right-of-way of a railroad track.	Construction	2 - 3 months	MAYBE	MAYBE	*Recommend consultation with UP to determine exact requirements.*
Southern Star Central Gas Pipeline, Inc.	Natural Gas Line Connection Approval	Connection to gas supplier.	Construction	2 - 3 months	YES	YES	*Also consider construction activities affecting existing gas lines.*
BPU Water Division	Water Line Connection	Connection to water supply	Construction	2 - 3 months	YES	YES	

ABBREVIATIONS:
AST - Aboveground Storage Tank
CAIR - Clean Air Interstate Rule
CAM - Compliance Assurance Monitoring
CAMR - Clean Air Mercury Rule
CEMs - Continuous Emissions Monitoring
CERCLA - Comprehensive Environmental Response, Compensation, and Liability Act of 1980
COE - US Army Corps of Engineers
CWA - Clean Water Act
DAQ - UG Department of Air Quality
DPW - UG Department of Public Works
DUP - UG Department of Urban Planning and Land Use
EPA - Environmental Protection Agency
FAA - Federal Aviation Administration
FD - UG Department of Fire
HD - UG Department of Health
KDHE - Kansas Department of Health and Environment
KDWP - Kansas Department of Wildlife and Parks
KSDA - Kansas State Department of Agriculture
KSFM - Kansas State Fire Marshal
LEPC - Local Emergency Planning Committee
NOI - Notice of Intent
NPDES - National Pollutant Discharge Elimination System
PSD - Prevention of Significant Deterioration
ROW - Right of Way
RMP - Risk Management Plan
SARA - Superfund Amendments and Reauthorization Act
SHPO - State Historic Preservation Officer
SPCC -Spill Prevention Control and Countermeasures Plan
SUP - Special Use Permit
SWPPP - Storm Water Pollution Prevention Plan
UP - Union Pacific
UG - Unified Government of Wyandotte County / Kansas City, Kansas
USFWS - United States Fish and Wildlife Service

Appendix G
Combustion Turbine Engineering and Construction Schedule


Bond Financing in Place
Mobilize Site
First Fire Unit
Planned Provisional Acceptance
Final Acceptance
2008
2009
2010
2011
ENGINEERING
CONSTRUCTION
COMBUSTION TURBINE (LM6000 or 7EA, SCR, Stack, 480V MCC for CT Auxiliaries)
GAS COMPRESSOR
TRANSFORMER
CHILLER
WATER TREATMENT
FIELD ERECTED TANKS (Oil & Water)
Met Monitoring for Air Permit
Prep Air Permit Application
Agency Review Air Permit Application
Issue Draft Permit
Issue Final Permit
Air Permit Receipt
Develop Poposal
Owner Select AE
Prep Spec, Bid, Evaluate, & Award CT Contract
Preliminary Engineering
Detailed Engineering
Field Engineering Support
Issue Spec GC
Award GC
General Contractor Bids
Purchase CT
Design Review Meeting
CT Fabricate and Deliver
CT DELIVERY TO SITE
CT on Base
UG Utilities & Foundations
CTG Erection
Foundation
Stack/SGR Erection
Reliability Run
Fabricate and Deliver Gas Compressor
Gas Cooler Erection/Comm
Fabricate and Deliver GSU Transformer
GSU Transformer Erection/Comm
Chiller Erection
Demin Equip Erection & Interconnect
Tank Fdn
Demin Tank Erection/Painting
Fuel Oil System Expansion
Gas Blows
Fuel Oil/Gas Piping
Issued for Gas Planning Study
Initial Draft
Revisions & Record of Issue
Black & Veatch Corporation
Engineer
Drawn
Clint Law
11-Jul-08
Checked
Date
Kevin Bogner
CT5 SIMPLE CYCLE
Kansas City Board of Public Utilities
DRAWING NUMBER
REV 1
CODE
AREA
PAGE 1 OF 1