VOLUME 4:

SUPPLY-SIDE RESOURCE ANALYSIS

KCP&L

INTEGRATED RESOURCE PLAN

4 CSR 240-22.040

** PUBLIC **

TABLE OF CONTENTS

TABLE OF FIGURES

TABLE OF TABLES

TABLE OF APPENDICES

TABLE OF APPENDICES (CONTINUED)

TABLE OF APPENDICES (CONTINUED)

Appendix 4.H

TABLE OF RULES COMPLIANCE

VOLUME 4: SUPPLY-SIDE RESOURCE ANALYSIS

SECTION 1: INTRODUCTION

The evaluation of supply-side resource alternatives began with identification of potential generating technologies, which can reasonably be implemented. After identifying these technologies, KCP&L conducted pre-screening evaluations to eliminate resources that have significant disadvantages in terms of utility costs, environmental costs, operational efficiency, risk or limited planning flexibility as compared to other available supply-side resource options.

In addition to evaluating new supply-side resources , KCP&L compared alternative sources of capacity and energy including potential refurbishment of existing generating assets, enhancements of emission controls at existing generation assets, efficiency improvements to reduce KCP&L's own energy use, upgrading transmission & distribution systems to reduce power and energy losses, Demand-Side resources and purchased power agreements (PPA).

Volume 4 of KCP&L's Integrated Resource Plan (IRP) provides the requirements of 4 CSR 240-22.040 in the order shown below:

1. Introduction
2. Executive Summary
3. Technology Pre-screening
4. Environmental Costs Included in "Utility Cost"
5. Probable Environmental Cost
6. Fuel Price Forecasts
7. Emission Allowance Price Forecasts

8. Existing Plant refurbishments & Environmental Enhancements

9. Transmission & Distribution Upgrades

10. Power Purchase Opportunities

11. Reporting Requirements

SECTION 2: EXECUTIVE SUMMARY

2.1 FOREWORD

Two future uncertainties have the potential to drive significant change within the utility industry and to strongly influence the selection of resource alternatives to be included in a preferred resource plan:

1. Potential greenhouse gas restrictions, and
2. Potential shortages of natural gas.

Together, these uncertainties have the potential to limit the addition of traditional and proven generating technologies, with the possible exception of nuclear and wind generation. In the near term, there are limited proven supply-side technologies, which can economically provide low or zero emissions of green house gas without reliance on natural gas. Nuclear is perhaps the only mature carbon-free supply-side technology that meets the full range of system reliability requirements for base load generation; however, there are significant uncertainties as to how the nuclear industry will evolve to meet the challenge of constructing a large number of nuclear plants over the next several decades. These uncertainties include:

- Construction cost range
- Adequate number of manufacturing, engineering and construction firms
- Dual construction and operating permitting process
- Certification of standard designs
- Waste disposal requirements and options

Wind is a viable and potentially competitive supply-side resource within certain limitations around the intermittency of the wind resource. The Production Tax Credit (PTC) for wind is currently a necessary component for keeping wind competitive. An additional consideration, even in the absence of the PTC, is the risk mitigation to future carbon reforms provided from the deployment of wind resources. It is also likely that with additional reforms that reduce the use of fossil fuels to reduce carbon emissions, there will be additional incentives and/or mandates legislated for the use of renewable resources in the near term.

Natural gas fired generation may play a role in the preferred plan; however, large scale reliance on this option carries exposure to fuel supply availability and cost risks, particularly if carbon restrictions drive significant fuel switching. Biomass is another currently available technology that reduces exposure to these two uncertainties. Like natural gas resources, the role of biomass may be limited by the availability of adequate and economic fuel supplies. Biomass may also serve a role when co-fired with coal on existing units to reduce the cost of emissions under a CO_2 cap-and-trade program or similar regulation.

Based on the wide range of impacts provided by the above uncertainties, it is important to select a preferred plan that offers reduced exposure to these two risks. The preferred resource plan must strongly consider roles for end use energy efficiency, demand side management, renewables and nuclear generation.

Integrated and Risk Analysis will quantify the economic impacts of these uncertainties based on the forecasted price of greenhouse gas allowances and natural gas pricing (See Volumes 6 and 7). The results of Integrated and Risk Analysis will provide a preferred resource plan to meet the objectives of the IRP rules including consideration of these two key uncertainties. In addition, contingency plans will address measures to further reduce exposure to future uncertainty risks.

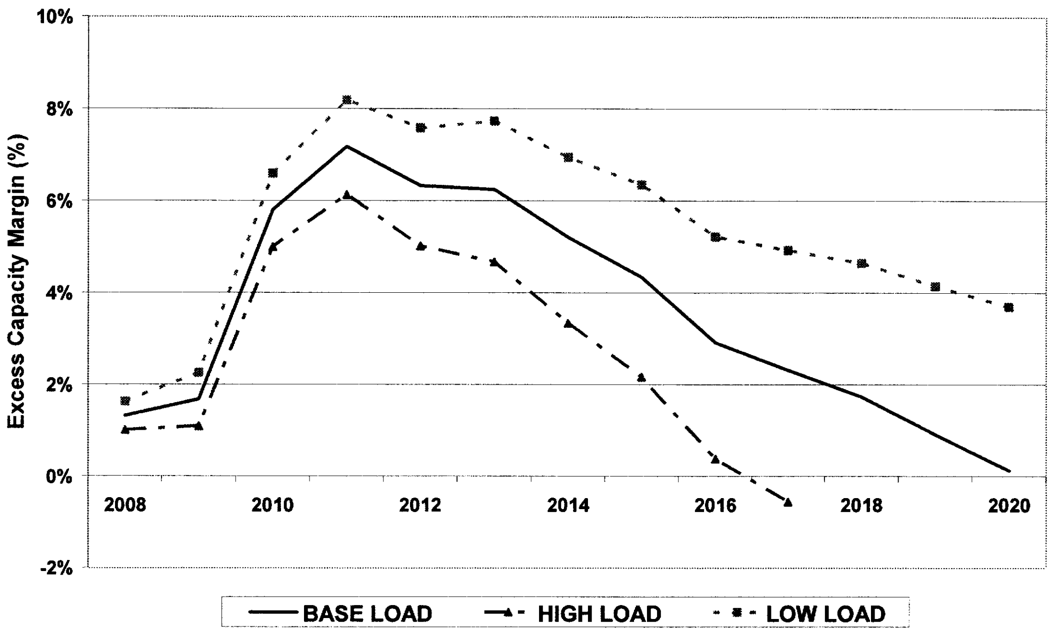
2.2 ROLE OF CAPACITY MARGIN IN RESOURCE PLANNING

Utilities are required to maintain at least a minimum level of generating capacity to provide for overall system reliability. For the Southwest Power Pool (SPP), the primary measure of adequate capacity is the capacity margin, or the percent of capacity in excess of projected peak loads. The minimum SPP capacity margin requirement is currently 12% and serves as one of the primary drivers requiring the installation of new supply-side and/or demand-side resources. KCP&L's capacity margin forecast for base, low and high forecasted load growth compared to capacity margin requirements is shown in Figure 1 below. The Y-axis, "Excess Capacity Margin", represents the capacity margin percentage with respect to the required minimum of 12%. For example, 4% represents a 16% capacity margin (4% higher than the 12% minimum). At 0%, KCP&L would just meet the 12% capacity margin requirement.

Based on the base load forecast, KCP&L's capacity margin is not expected to require new supply-side and/or demand-side additions until the 2020 timeframe. The base forecast can be impacted by numerous uncertainties including future economic growth, improved end-use efficiency and potential technology developments. One such technological development with the potential to increase load projections is the introduction and public acceptance of Plug-in Hybrid Electric Vehicles (PHEV). For this IRP filing, KCP&L did not evaluate the potential impacts of this uncertainty. This scenario will be evaluated in future planning efforts and will a consideration in the on-going contingency planning pursuant to this filing.

Figure 1: Capacity Margin Requirements

Projected KCP&L Capacity Margins Above Required



2.3 PURPOSE OF SUPPLY-SIDE ANALYSIS

The purpose of Supply-Side Analysis is to rank supply-side resource alternatives to select those technologies meriting further consideration as future alternatives to meet customer energy needs. Technologies that pass the pre-screening analysis are moved into Integrated Analysis and included in alternative resource plans. Those alternative plans are then compared to identify the mix of future resources that best meet the objectives of the IRP rules.

Supply-Side Analysis includes several distinct processes:

1. Technology pre-screening

    a. Identify viable alternative resource technologies

    b. Develop the cost and performance measures to fully evaluate each identified technology

c. Rank technologies on the basis of current cost expectations ("Utility Cost") and on the basis of potential future cost expectations ("Probable Environmental Cost")

d. Identification of technologies to pass on to Integrated and Risk Analysis.

2. Evaluation of alternatives to supply-side additions

   a. Transmission and Distribution (T&D) system upgrades

   b. Enhancements and life assessment for existing generating resources

   c. Emission control enhancements

   d. Purchase power agreements (PPAs) from outside sources

3. Forecasts of key cost uncertainties, primarily fuel and emissions allowance prices as well as the range of costs associated with installing new supply-side resources.

2.4 PRE-SCREENING

IRP rules require evaluation and ranking of technologies under two cost categories:

- Utility Cost, or expected costs under current regulations; and
- Probable Environmental Cost (PEC), or the expected Utility Cost plus the anticipated cost of potential future environmental regulations.

For pre-screening, KCP&L focused on the Probable Environmental Cost rankings. These rankings are more indicative of long-term expected mandates that may be required under future carbon reduction scenarios. Rankings under both required measures, Utility Cost and Probable Environmental Cost, did not produce significant surprises. Coal, nuclear and wind routinely ranked above other alternatives. Under the Utility Cost measure, coal-fired generation was ranked above wind and nuclear respectively. Integrated Gasification Combined Cycle (IGCC), combined-cycle and biomass alternatives were ranked next, followed by fuel cells, small scale generation, energy storage, "other renewables" and solar. Gas fired peakers still appear to be the preferred choice for peak load needs.

Under Probable Environmental Cost, the more indicative cost comparison, wind moved to the top of the rankings followed by nuclear and coal-fired generation, respectively. The remaining technologies ranked in essentially their same position as under Utility Cost. See Tables 3-6 for detailed rankings.

The supply-side technologies passed-on to Integrated and Risk Analysis are listed below and shown again in Table 9 in Section 3.2.5:

- Supercritical Pulverized Coal
- Carbon capture and sequestration (CCS) retrofits (existing units)
- Nuclear
- Wind
- Integrated Gasification-Combined Cycle (IGCC),
- Combustion Turbines (CT)
- Combined Cycle (CC)
- Biomass co-firing for existing coal-fired units
- Solar to meet potential Missouri renewable ballot initiatives

Energy efficiency and Demand Side Management programs were also evaluated in Integrated Analysis.

2.5 ALTERNATIVES TO SUPPLY-SIDE ADDITIONS

In response to Rule 22.040 (7), potential upgrades to KCP&L's T&D systems were evaluated as an alternative to supply-side additions. Details of the T&D evaluations are included in Section 9.1.1 of this report. The T&D results indicated that upgrading line-size is not an economic alternative without other drivers supporting the upgrades. Similarly, evaluations of transformer upgrades indicated that a system-wide program of replacements was not an economic choice. Regarding transformer efficiency, KCP&L has standardized on the purchase of DOE 2010 compliant transformers for future installations and replacements. These transformers provide improved efficiency over current DOE standards and meet the DOE's Standard Level of efficiency for transformers installed after January 1, 2010. The internal standard was established based on an analysis by KCP&L Engineering which indicated that the DOE 2010 standard provided the lowest cost of ownership. This analysis is attached as Appendix 4.H.

In response to Rule 22.040 (4), the evaluation of enhancements for existing generating resources was accomplished through a Black & Veatch (B&V) study commissioned by KCP&L. The study identified a wide variety of efficiency improvement projects. The study included benefit-cost evaluations of more than 100 potential projects. The projects passing the benefit-cost analysis are expected to be implemented through inclusion in KCP&L's annual capital and O&M budgeting processes. The B&V study is attached as Appendix 4.D.6.

Unit life analysis of existing generating resources was provided by an internal KCP&L review process called Life Assessment and Management Planning (LAMP). This process identifies future risks to unit performance and the anticipated replacements or maintenance efforts that will be required to maintain reliable performance over the 20-year planning period. Results of the LAMP process are shown in Table 15 through Table 21 in the body of this report.

Enhancement of emissions controls is presently included in KCP&L budget forecasts for LaCygne Units 1 and 2 and the Montrose Station units. These units are subject to emission regulation under the Clean Air Mercury Rule (CAMR). Although CAMR was recently vacated by the court, it is anticipated that future rulemaking will require mercury controls on these units. LaCygne Units 1 and 2 and Montrose Unit 3 are also subject to Regional Haze regulations, also known as the Best Available Retrofit Technology Rule (BART). The Montrose units are also subject to the Clean Air Interstate Rule (CAIR). Like CAMR, CAIR was recently vacated by the court and future rulemaking is expected to replace CAIR regulation. Under these or future regulations and/or potential future rulemaking, the units are anticipated to require the addition of scrubbers for SO_2 removal, Selective Catalytic Reduction (SCR) or other equipment additions for NO_x removal and baghouses for particulate and mercury removal. The projected cost of these additions is included in the 20-year budgets utilized for the IRP. After including the environmental retrofits underway on Iatan Unit 1, all KCP&L generating units are anticipated to meet these regulations with their current configurations.

In response to Rule 22.040 (5), Power Purchase Agreements (PPAs) were evaluated through a Request for Proposal (RFP) issued in August of 2007. Evaluation of the proposals received indicated that long-term PPAs were more costly than ownership alternatives. Additionally, the proposals will not remain valid for the 2020 timeline when KCP&L projects the potential need for new resources. The primary value of the RFP is to provide data points for the market value of PPAs. A discussion of the RFP evaluations is included in Section 10: of this report.

2.6 FUEL AND EMISSION FORECAST UNCERTAINTY

Forecasts of fuel prices are included in Section 6: and emission allowance prices are included in Section 7:. It should be noted that these forecasts were "locked-down" fairly early in the IRP process to allow for model building and testing prior to Integrated Analysis. The required early lock-down resulted in a natural gas forecast that is likely lower than a forecast developed from today's market data. A higher natural gas price forecast would change the economics of natural gas-fired technologies and tend to limit the viability of natural gas as an economic technology alternative.

SECTION 3: TECHNOLOGY PRE-SCREENING

3.1 PRE-SCREENING INTRODUCTION

The purpose of technology pre-screening is to provide an analysis and economic ranking of technologies available for meeting long-term energy supply requirements. Results of the pre-screening provide the basis for selecting those technologies which merit further evaluation under integrated analysis.

For pre-screening, KCP&L employed two levels of pre-screening prior to selection of technologies to pass to Integrated and Risk Analysis. The first level was to eliminate those technologies demonstrating excessive costs, high risk or other disadvantages pursuant to the evaluations specified in Rule 4 CSR 22.040, Supply-Side Analysis. The second level of pre-screening involved optimization modeling performed by Ventyx. Optimization modeling utilizes the Capacity Expansion Module© (CEM) of MIDAS™ to select combinations of supply-side and demand-side programs to provide preferred resource plans under varying scenarios addressing future uncertainties.

Technology cost and performance data were provided to Ventyx by KCP&L and are attached in Appendix 4.A.7, Technology Templates for Second Level Pre-screening – Ventyx CEM Modeling. It should be noted that for the Ventyx optimization modeling, cost data for three technologies were updated from the cost based on EPRI TAG® used in the first level pre-screening process. The combined cycle cost was based on a current estimate received from a combined cycle provider. Combustion turbine costs were based on results of a combustion turbine cost study commissioned by KCP&L. Wind technology costs were based on project proposals received by KCP&L for current projects KCP&L is assessing. The basis and development of these updated cost estimates are attached in Appendix 4.A.8, Second Level Pre-screening Technology Cost Development Background Data. A complete discussion of Ventyx optimization modeling is included under "Volume 6: Integrated Analysis", Section 2.

Results from the optimization modeling were used as an additional level of screening to eliminate some technologies from further consideration.

3.1.1 INITIAL TECHNOLOGY EXCLUSIONS

Pursuant to 22.040 (9) (A) 3, some technologies are excluded from the first level of pre-screening evaluation. For example, central station geothermal resources require specific geologic characteristics that are not adequately available in the Midwest U.S. Technologies excluded from pre-screening evaluations are shown in Table 1 below:

Table 1: Technology Exclusions

Technology	Reason for Exclusion
Central Station Geothermal	Region lacks adequate geologic resources
Hydro	Region lacks adequate resources, high developmental costs and environmental opposition
Pumped Storage	Region lacks adequate geographic features, high developmental cost
Developmental Technologies	See discussion below

For hydro, KCP&L has formally indicated interest in the proposed conversion of existing locks on the Mississippi river to add generation capability. No indication of further development has been received regarding this potential project. For energy storage, KCP&L evaluated Compressed Air Energy Storage (CAES). A comparison to pumped storage indicated CAES was a lower cost alternative.

Developmental Technologies

KCP&L continues to monitor the development of emerging and advanced technologies that could provide economic contingencies for increasingly stringent environmental restrictions, fuel supply disruptions or other future uncertainties. These developing technologies include Partial and Full Oxygen Enhanced Combustion, Plasma Arc Gasifier systems and Pebble Bed Modular Reactors for nuclear generation. Although not considered as viable supply side alternatives for Integrated Analysis due to their experimental nature, these are technologies KCP&L will monitor for future considerations.

Partial Oxy-combustion

Partial Oxy-combustion involves replacement of 5 to 10% of the combustion air with pure oxygen. Test show that NO_x reductions in the range of 30 to 40% may be obtained by using this method. Additional equipment requirements are Cryogenic Air Separation Units (ASU) or the use of Oxygen Transport Membranes and ceramic membranes using the properties of Perovskites to separate oxygen from air. Demonstration tests have been completed over the past decade at several utilities.

Full Oxy-combustion

Oxy-fuel firing replaces ambient combustion air with an Oxygen and CO_2 rich combustion air mix. This process significantly reduces NO_x levels and concentrates the CO_2 in the flue gas stream allowing for CO_2 capture and sequestration. Several demonstration projects have been performed and a full scale project to demonstrate Oxy-fuel coal firing and capture/storage of CO_2 has been announced at the Callide Plant in Queensland, Australia. The boiler retrofit is scheduled for completion by the end of 2008. Sequestration is scheduled to go on-line in 2010. Additional demonstration projects are in progress to utilize the BOC Groups CAR (Ceramic Auto-thermal Recovery) system to strip oxygen from air and use recycled flue gas to sweep the oxygen into the combustion air system.

Plasma Arc Gasifiers

Plasma Arc Gasifiers utilize very high temperature (5000 to 15000° C) plasma arc furnaces to create a synthetic gas (Syngas) that is then burned in combustion turbines to produce electricity. The process can utilize many fuels such as coal, biomass and waste products. The process results in minimal emissions through gas cleaning. Emissions (by-products) from this application would primarily consist of an inert slag.

Thermoselect Gasifier Systems

The Plasma Arc Gasifiers differ somewhat from the Interstate Waste Technologies Thermoselect ® system that converts all types of waste into Syngas. The Thermoselect ® systems utilize conversion chambers that operate at lower temperatures (1200 – 2000° C) in a pure oxygen atmosphere to accomplish gasification.

Pebble Bed Modular Reactors

The Pebble Bed Modular Reactor (PBMR) is a graphite moderated, helium cooled reactor utilizing an inherently safe pebble design that allows the unit to run at higher temperatures (900° C). The pebbles are constructed of fissile kernels inside a multiple layered coating which do not deteriorate to temperatures above 2000° C. The heated helium is sent to a Gas Turbine for electricity production. The reactors can also provide thermal energy for a variety of other processes such as petroleum refineries, oil sand separation and desalination. Eskom in South Africa is presently in the process of building a PBMR rated at 500MWth. Initial criticality is planned for 2013. The very safe design, containment of fission products within the pebble, small waste volumes, small footprint and variety of applications make this an attractive alternative. This nuclear alternative is developmental and not currently an approved design with the U.S. Nuclear Regulatory Agency.

3.1.2 SUMMARY OF TECHNOLOGIES PRE-SCREENED

A total of thirty-nine technologies were identified and evaluated under a first level of pre-screening. These technologies were subdivided into the following categories (See Table 2 below):

1) Base Load – Pulverized Coal (PC), Fluidized Bed Combustion (FBC), Integrated Gasification Combined Cycle (IGCC) and Nuclear Power

2) Intermediate Load - Combined Cycle (CC), Energy Storage and Fuel Cells

3) Peaking Load – Combustion Turbines (CT) and Small Scale Alternatives

4) Renewables –Solar, Wind, Biomass, and Waste to Energy

Table 2: Generating Technology Categories

Base Load		
Pulverized Coal & FBC	**Integrated Gasification Combined Cycle**	**Nuclear**
SCPC Pittsburg Bit WFGD	IGCC ILL #6 CoP	Nuclear - U.S. EPR
SCPC ILL #6 WFGD	IGCC ILL #6 CoP CO2 Capture	Nuclear - G.E. ABWR
SCPC ILL #6 WFGD CO2 Capture	IGCC ILL #6 Shell	Nuclear - G.E. ESBWR
SCPC PRB SDA	IGCC ILL #6 Shell CO2 Capture	Nuclear - Westinghouse AP1000
USCPC PRB WFGD	IGCC ILL #6 GE Radiant	
USCPC PRB WFGD CO2 Capture	IGCC ILL #6 GE Radiant CO2 Capture	
Fluidized Bed Combustion (FBC)		
Intermediate Load		
Combined Cycle	**Energy Storage and Fuel Cells**	
CT/Combined Cycle (PG7001H)	Compressed Air Energy Storage System	
CT/CC	Fuel Cells (Phosphoric Acid Fuel Cells)	
	Molten Carbonate Fuel Cells	
	Solid Oxide Fuel Cells - Ambient Pressure	
	Proton Exchange Membrane	
	NaS Batteries	
Peaking Load		
Combustion Turbines	**Small Scale Alternatives**	
GE PG7121 Heavy Duty	Internal Combustion Engines - Oil	
CT Conventional	Internal Combustion Engines - Natural Gas-Spark Ignition	
	Small Scale CT Dual-Fuel Capable: Natural Gas Fired	
	Small Scale CT Dual-Fuel Capable: Oil Fired	
Renewables		
Solar	**Wind & Biomass**	**Waste to Energy**
Solar Parabolic Trough w/Thermal Storage	Wind	Landfill Gas
Dish/Stirling Engine 100% Solar	Biomass Stoker-Fired Stoker	Animal-Waste
Photovoltaic Flat Plate Thin Film	Biomass Fluidized Bed	

Each of the thirty-nine technologies were initially ranked using an "average annual utility cost" pursuant to 22.040 (2) (A). This initial ranking utilized the long-term average cost of fuel and other cost components to provide a typical, or average, one-year cost of production for each technology. Utility cost, expressed in dollars per megawatt-hour ($/MWh), provides the expected annualized cost of production from each technology including the levelized annual cost to finance the technology installation. The utility cost for each technology was derived by summing the levelized annual carrying cost of installation, transmission, fixed O&M, variable O&M, existing environmental cost and fuel cost.

Pursuant to Rule 22.040 (6) a determination was made that new sources of generation would require new transmission facilities. The cost of new transmission facilities was based on the waiver described in "Staff Recommendation To Grant Variances With Conditions", Case No. EE-2008-0034, dated March 7, 2008, Item 6, transmission cost was derived utilizing recent transmission-related cost data from KCP&L's Osawatomie and Iatan-2 construction projects The details of the transmission cost calculation is attached in Appendix 4.F.2. Also included in Appendix 4.F as required by the above sited Staff Recommendation, is documentation of the Southwest Power Pool (SPP) process for derivation of transmission interconnection and long-term firm transmission service costs. The costing process, Large Generator Interconnect Procedure (LGIP) guidelines and Long Term Firm Transmission Service Guidelines are attached in Appendices 4.F.1 as 4.F.1.1 and 4.F.1.2, respectively. The exception to using the transmission cost calculation was for wind generation. Due to the remote location of some of premium sites for wind installations, the transmission cost was increased by an additional 50%.

Although KCP&L requested a variance in the February 5, 2008 "Application for Waivers Concerning Kansas City Power & Light Company's August 2008 Integrated Resource Plan Submission" to use only the initial ranking based on "average annual utility cost", a second ranking was performed to demonstrate utility cost in nominal dollars over the expected life of the generating unit for each technology. This second ranking provides the nominal utility cost as specifically required by Rule 22.040 (2). To calculate nominal utility cost over a technology's life cycle, long-term average costs were replaced by escalated costs and forecasted annual fuel and emission allowance pricing, all expressed in nominal dollars for each year of the technology's life cycle. The resulting nominal cost is expressed as $/MWh in 2008 dollars.

Comparing the results of the two rankings demonstrates small differences between the two approaches. The relative position of technologies did not change significantly. For example, solar, biomass, small scale technologies, fuel cells and energy storage remain ranked below the more traditional generating technologies in both cases.

In the Staff's Non-Unanimous Stipulation and Agreement for Case No. EO-2007-008 dated February 13, 2007, the staff could not determine if KCP&L used busbar costs in the analysis of supply-side resources. The utility costs discussed above are calculated as the busbar cost for each technology. It should be further noted that the cost rankings discussed above only serve as a pre-screen to eliminate those technologies with significant cost or other disadvantages. Integrated and Risk Analysis are required to adequately evaluate alternative technologies within a generating portfolio.

3.2 PRE-SCREENING RESULTS

The pre-screening evaluation is in response to Rule 22.040 (2). Two levels of pre-screening were performed by KCP&L. The purpose for performing two levels of pre-screening are discussed in Section 3.2.3. In order to ensure cost and performance data are based on similar assumptions, the data for each technology was primarily based on Electric Power Research Institute (EPRI) TAG®, Report 1014115, December, 2007 data. EPRI is widely considered the industry standard and authoritative source for costs and performance of electric generating technologies. It should be noted that EPRI TAG® includes the specific environmental costs required by Rules 22.040 (1) (K) 2 through 22.040 (1) (K) 4., which refer to waste generation, water usage and siting impacts. The calculations of the annual average utility cost and the life-cycle nominal utility cost for each of the thirty-nine technologies are attached in Appendix 4.A.1 and 4.A.2, respectively. The base cost and performance assumptions utilized in calculating life-cycle nominal utility cost are attached in Appendix 4.A.3. References for the source documents utilized to evaluate each technology are shown at the end of Appendix 4.A.6.

Exceptions to using EPRI TAG® for cost and performance data for the first pre-screening evaluation were for technologies that include carbon capture and sequestration (CCS) – Super Critical Pulverized Coal (SCPC), Ultra Super Critical Pulverized Coal (USCPC), and Integrated Gasification Combined Cycle (IGCC). Cost and performance data for technologies that include CCS were derived from EPRI Report 1013355, March, 2007. It should be noted that the cost adder for CCS does include cost of CO_2 transportation, storage, and monitoring. Other technologies where cost and performance data were derived from a reference source other than EPRI TAG® were Animal Waste and NaS Batteries. The data sources for these two technologies are also listed in the reference list attached in Appendix 4.A.6.

As required by the IRP rules, pre-screening evaluations include two views of technology costs:

1. Utility Cost, or the expected cost of the technology under current regulation, and

2. Probable Environmental Cost or the expected cost of the technology under anticipated future environmental regulations.

For determining Utility Cost, KCP&L includes the projected cost of compliance with the Clean Air Mercury Rule (CAMR) and the Clean Air Interstate Rule (CAIR). These costs are projected based on forecasted pricing of emission allowances for SO_2, NO_x and mercury. Note that the installed capital costs shown in the prescreening evaluations include the cost of Best Available Control Technology (BACT) for these emissions. Therefore, the capital and operating cost impacts of meeting control requirements for these pollutants is captured for each technology. Additionally, the current environmental cost will utilize the forecasted allowance prices for SO_2, NO_x and mercury applied to the appropriate emission rate of each technology. CAMR and CAIR were recently vacated by Federal court decisions and returned to the EPA for further rulemaking. For evaluations included in this IRP, KCP&L assumes that the current allowance price forecast for mercury emissions is representative of the cost that will be incurred through any potential future rulemaking.

For determining Probable Environmental Costs, KCP&L included the following additional regulations that may be imposed over the 20-year planning horizon:

1. Greenhouse gas restrictions in the form of a cap and trade market
2. Requirements to landfill all coal combustion by-products
3. The addition of cooling towers and fish impingement protection
4. Potential need to add control for zebra mussels
5. Various future potential air emissions requirements.

Probable environmental costs are discussed in greater detail in Section 5: of this report. Appendix 4.B contains additional background information and a narrative discussion of existing and potential future environmental regulation. Under Appendix 4.B, Appendix 4.B.1 shows the calculation of probable environmental cost for the thirty-nine technologies reviewed in the first level of pre-screening. Appendix 4.B.2 is a detailed narrative review of general environmental regulations facing utilities. Appendix 4.B.3 provides the cost calculations for the specific Probable Environmental Costs applied to technologies under pre-screening including (1) landfill all coal combustion by-products, (2) various future potential air emissions requirements and (3) zebra mussel control. The cost impacts of adding cooling towers and fish protection are already included in the base cost of technologies pre-screened. The cost impacts of potential greenhouse gas restrictions are calculated based on forecasted allowance prices and the CO_2 emission rates of each technology.

3.2.1 PRE-SCREENING RANKING BASED ON UTILITY COST

The uncertainty analysis required by 22.040 (8) was completed for each technology included in the second level pre-screening evaluations. The uncertainties evaluated included:

- Fuel price forecasts pursuant to 22.040 (8) (A) (see Section 6:)
- Estimated capital costs pursuant to 22.040 (8) (B) (see Table 3 below) Note that these capital costs include **[redacted]** for transmission additions where required. The exception to the **[redacted]** cost was for wind, a cost of **[redacted]** was used due to the remote location of wind generation.
- Estimated annual fixed and variable operating and maintenance costs pursuant to 22.040 (8) (C) (see Table 3 below)
- Emission allowance costs pursuant to 22.040 (8) (D) (see Section 7:)
- Regarding rule 22.040 (8) (E), no leased or rented facilities are included in any alternative resource plans and do not apply to the IRP evaluations

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Table 3: Capital, Fixed and Variable Cost Estimates
**** Highly Confidential ****

	SCPC	SCPC w/CCS	Circulating Fluid Bed	IGCC	IGCC w/CCS	Combined Cycle
[redacted]						
	CT	Nuclear	Wind	CAES	Molton Carbon Fuel Cells	Solar Parabolic Trough
[redacted]						
	Photovoltaic Flat Plate	Micro-turbines	10% Biomass	50%/100% Biomass	Biomass Fluidized Bed	
[redacted]						

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Pursuant to Rule 22.040 (2) (C), the economic ranking of technologies by Utility Cost are shown in Table 4 and Table 5. Table 4 is the "average annual Utility Cost" ranking. Table 5 is the nominal Utility Cost ranking over the expected life of the generating unit.

Table 4: Ranking By Utility Cost ** Highly Confidential **

RANK	Technology	Installed Net Cost ($/kW)	Capacity (MW)	Capacity Factor	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Fuel Price ($/MBtu)	Utility Cost ($/MWh)
1	USCPC PRB WFGD	[redacted]							
2	Nuclear - G.E. ESBWR								
3	SCPC PRB SDA								
4	Nuclear - G.E. ABWR								
5	Nuclear - Westinghouse AP1000								
6	Nuclear - U.S. EPR								
7	SCPC ILL #6 WFGD								
8	SCPC Pittsburg Bit WFGD								
9	Fluidized Bed Combustion (FBC)								
10	Wind								
11	IGCC ILL #6 CoP								
12	IGCC ILL #6 GE Radiant								
13	IGCC ILL #6 Shell								
14	Landfill Gas								
15	USCPC PRB WFGD CO2 Capture								
16	Biomass Fluidized Bed								
17	IGCC ILL #6 CoP CO2 Capture								
18	IGCC ILL #6 GE Radiant CO2 Capture								
19	SCPC ILL #6 WFGD CO2 Capture								
20	Biomass Stoker-Fire Stoker								
21	CT/Combined Cycle (PG7001H)								
22	IGCC ILL #6 Shell CO2 Capture								
23	Animal Waste								
24	CT/CC								
25	Molten Carbonate Fuel Cells								
26	Solar Parabolic Trough w/Thermal Storage								
27	Solid Oxide Fuel Cells - Ambient Pressure								
28	NaS Batteries								
29	Proton Exchange Membrane								
30	Combustion Turbine GE PG7121 Heavy Duty								
31	Compressed Air Energy Storage System								
32	Combustion Turbine Conventional								
33	Internal Combustion Engines - Natural Gas-Spark ignition								
34	Small Scale CT Dual-Fuel Capable: Natural Gas Fired								
35	Internal Combustion Engines - Oil								
36	Photovoltaic Flat Plate Thin Film								
37	Small Scale CT Dual-Fuel Capable: Oil Fired								
38	Fuel Cells (Phosphoric Acid Fuel Cells)								
39	Dish/Stirling Engine 100% Solar								

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Table 5: Ranking By Nominal Utility Cost ** Highly Confidential **

RANK	Technology	Capacity Factor (%)	Nominal Utility Cost ($/MWh)
1	USCPC PRB WFGD	85%	[redacted]
2	SCPC PRB SDA	85%	[redacted]
3	SCPC ILL #6 WFGD	85%	[redacted]
4	SCPC Pitt Bit WFGD	85%	[redacted]
5	Fluidized Bed Combustion	85%	[redacted]
6	Wind	38%	[redacted]
7	Nuclear GE ESBWR	90%	[redacted]
8	IGCC ILL #6 Cop	85%	[redacted]
9	Nuclear GE ABWR	90%	[redacted]
10	Nuclear Westinghouse AP1000	90%	[redacted]
11	Nuclear US EPR	90%	[redacted]
12	IGCC Ill#6 Shell	85%	[redacted]
13	IGCC ILL #6 GE Radiant	85%	[redacted]
14	USCPC PRB WFGD CO2 Cap	85%	[redacted]
15	IGCC ILL #6 Cop CO2 Cap	85%	[redacted]
16	CT Combined cycle (PG7001H)	30%	[redacted]
17	IGCC ILL #6 GE Radiant CO2 Cap	85%	[redacted]
18	CT/CC	30%	[redacted]
19	IGCC ILL #6 Shell CO2 Cap	85%	[redacted]
20	Molten Carbonate Fuel Cell	95%	[redacted]
21	SCPC ILL #6 WFGD CO2 CAP	85%	[redacted]
22	Biomass Fluid Bed	90%	[redacted]
23	Landfill Gas	85%	[redacted]
24	NaS Batteries	30%	[redacted]
25	Animal Waste	85%	[redacted]
26	Solid Oxide Fuel Cells	30%	[redacted]
27	Biomass Stoker	80%	[redacted]
28	Solar Parabolic Trough	40%	[redacted]
29	Proton Exchange Membrane	30%	[redacted]
30	Compressed Air Energy Storage	30%	[redacted]
31	Combustion Turbine GE PG7121 HD	10%	[redacted]
32	Small Scale CT Dual- Fuel Capable - Natural Gas	10%	[redacted]
33	Internal Combustion Engine - Natural Gas - Spark Ignition	10%	[redacted]
34	CT Conventional	10%	[redacted]
35	Fuel Cell Phos. Acid	30%	[redacted]
36	Small Scale CT Dual-Fuel Capable - Oil	10%	[redacted]
37	Photovoltaic Flat Plate Thin Film	24%	[redacted]
38	Internal Combustion Engine - Oil	10%	[redacted]
39	Dish Stirling Engine Solar	20%	[redacted]

3.2.2 PRE-SCREEN RANKING BASED ON PROBABLE ENVIRONMENTAL COST (PEC)

Pursuant to Rule 22.040 (2) (C), the economic ranking of technologies by Probable Environmental Cost (PEC) are shown in Table 6 and Table 7. Table 6 shows the economic ranking based on annual average Probable Environmental Cost. Table 7 shows the rankings in nominal Probable Environmental Cost over the expected life of each technology. Nominal probable environmental cost calculations for each of the thirty-nine technologies are attached in Appendix 4.A.4. The assumptions utilized in calculation of nominal probable environmental cost for each technology are attached in Appendix 4.A.5. The difference between nominal utility cost and nominal probable environmental cost is the inclusion of CO_2 emission rates and the added cost impacts to landfill all coal combustion by-products, control zebra mussels and meet various future potential air emissions requirements. The cost differences for each technology can be viewed by comparing results from Table 5: Ranking By Nominal Utility Cost to Table 7: Ranking By Nominal Probable Environmental Cost.

Table 6: Ranking By PEC ** Highly Confidential **

RANK	Technology	Installed Costs ($/kW)	Capacity (MW)	Capacity Factor	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Heat Rate (Btu/kWh)	Fuel Price ($/Mbtu)	Probable Environmental Cost ($/MWh)
1	Nuclear - G.E. ESBWR	[redacted]							
2	Nuclear - G.E. ABWR	[redacted]							
3	Nuclear - Westinghouse AP1000	[redacted]							
4	Nuclear - U.S. EPR	[redacted]							
5	Wind	[redacted]							
6	USCPC PRB WFGD	[redacted]							
7	Landfill Gas	[redacted]							
8	Biomass Fluidized Bed	[redacted]							
9	SCPC PRB SDA	[redacted]							
10	USCPC PRB WFGD CO2 Capture	[redacted]							
11	Biomass Stoker-Fired Stoker	[redacted]							
12	IGCC ILL #6 CoP CO2 Capture	[redacted]							
13	Animal-Waste	[redacted]							
14	SCPC ILL #6 WFGD	[redacted]							
15	IGCC ILL #6 GE Radiant CO2 Capture	[redacted]							
16	SCPC Pittsburg Bit WFGD	[redacted]							
17	Molten Carbonate Fuel Cells	[redacted]							
18	SCPC ILL #6 WFGD CO2 Capture	[redacted]							
19	IGCC ILL #6 CoP	[redacted]							
20	IGCC ILL #6 Shell CO2 Capture	[redacted]							
21	Fluidized Bed Combustion (FBC)	[redacted]							
22	CT/Combined Cycle (PG7001H)	[redacted]							
23	Solar Parabolic Trough w/Thermal Storage	[redacted]							
24	IGCC ILL #6 Shell	[redacted]							
25	IGCC ILL #6 GE Radiant	[redacted]							
26	CT/CC	[redacted]							
27	Solid Oxide Fuel Cells - Ambient Pressure	[redacted]							
28	NaS Batteries	[redacted]							
29	Proton Exchange Membrane	[redacted]							
30	Compressed Air Energy Storage System	[redacted]							
31	GE PG7121 Heavy Duty	[redacted]							
32	CT Conventional	[redacted]							
33	Internal Combustion Engines - Natural Gas-Spark Ignition	[redacted]							
34	Small Scale CT Dual-Fuel Capable: Natural Gas Fired	[redacted]							
35	Photovoltaic Flat Plate Thin Film	[redacted]							
36	Internal Combustion Engines - Oil	[redacted]							
37	Small Scale CT Dual-Fuel Capable: Oil Fired	[redacted]							
38	Fuel Cells (Phosphoric Acid Fuel Cells)	[redacted]							
39	Dish/Stirling Engine 100% Solar	[redacted]							

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Table 7: Ranking By Nominal Probable Environmental Cost

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RANK	Technology	Capacity Factor (%)	Nominal Probable Environmental Cost $/MWh
1	Wind	38%	[redacted]
2	Nuclear GE ESBWR	90%	
3	Nuclear GE ABWR	90%	
4	Nuclear Westinghouse AP1000	90%	
5	Nuclear US EPR	90%	
6	USCPC PRB WFGD	85%	
7	SCPC PRB SDA	85%	
8	USCPC PRB WFGD CO2 Cap	85%	
9	Molten Carbonate Fuel Cell	95%	
10	IGCC ILL #6 Cop CO2 Cap	85%	
11	SCPC ILL #6 WFGD	85%	
12	SCPC Pitt Bit WFGD	85%	
13	CT Combined cycle (PG7001H)	30%	
14	Biomass Fluid Bed	90%	
15	Fluidized Bed Combustion	85%	
16	IGCC ILL #6 GE Radiant CO2 Cap	85%	
17	Landfill Gas	85%	
18	NaS Batteries	30%	
19	SCPC ILL #6 WFGD CO2 CAP	85%	
20	CT/CC	30%	
21	IGCC ILL #6 Shell CO2 Cap	85%	
22	IGCC ILL #6 Cop	85%	
23	Animal Waste	85%	
24	Solid Oxide Fuel Cells	30%	
25	IGCC Ill#6 Shell	85%	
26	Biomass Stoker	80%	
27	IGCC ILL #6 GE Radiant	85%	
28	Solar Parabolic Trough	40%	
29	Proton Exchange Membrane	30%	
30	Compressed Air Energy Storage	30%	
31	Combustion Turbine GE PG7121 HD	10%	
32	Small Scale CT Dual- Fuel Capable - Natu	10%	
33	Internal Combustion Engine - Natural Gas	10%	
34	CT Conventional	10%	
35	Fuel Cell Phos. Acid	30%	
36	PV Flat Plate Thin Film	24%	
37	Small Scale CT Dual-Fuel Capable - Oil	10%	
38	Internal Combustion Engine - Oil	10%	
39	Dish Stirling Engine Solar	20%	

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Note that Table 4, Table 5, Table 6, and Table 7 satisfy requirement 22.040 (9) (A) 1. as specified in 4 CSR 22.040, Supply-Side Analysis.

3.2.3 TECHNOLOGIES ELIMINATED AFTER FIRST LEVEL PRE-SCREENING

Pursuant to Rule 22.040 (2) (C) technologies that were eliminated from further analysis are discussed below with a brief explanation of the reason for exclusion. In some cases, technologies with relatively low pre-screen rankings were passed on to the second level of pre-screening, which was performed by Ventyx. In general, the low ranking technologies passed on to the second level of pre-screening were determined to offer benefits for contingency planning under potential greenhouse gas restrictions.

Fluidized Bed Combustion (FBC). Coal-fired Fluidized Bed Combustion (FBC) was eliminated from second level pre-screening based on pre-screening rankings, which demonstrated a lack of substantial benefits over pulverized coal (PC) technologies. Additionally, KCP&L has several decades of operating knowledge and expertise with PC generation technologies. Migrating to FBC technology would require significant training costs and limit KCP&L's flexibility to rotate operations personnel between plants.

Biomass Stoker. This technology was eliminated from second level pre-screening based on high cost and lack of benefits over biomass Fluidized Bed technology.

Ultra Super Critical Pulverized Coal (USCPC) Technologies. For Integrated Analysis, KCP&L utilized the Supercritical Pulverized Coal technology using Powder River Basin (PRB) coal. Because USCPC technology is currently listed as "demonstration" by EPRI, it was excluded from the second level pre-screening by Ventyx. If Pulverized Coal (PC) resources are considered in the future, KCP&L will include USCPC as a potential supply-side alternative resource.

Small Scale Generation. These technologies were eliminated from second level pre-screening due to high cost and potential siting and permitting limitations.

Landfill Gas (LFG). KCP&L research indicates a maximum of approximately 30 MW of landfill gas generation is available regionally including east to Columbia, Missouri—west to Topeka, Kansas and north to St. Joe, Missouri—south to Springfield, Missouri. This limitation indicates that LFG cannot be a significant resource for meeting future energy needs. Based on the first level pre-screening ranking of LFG, this technology was eliminated from second level pre-screening. However, adoption of the limited LFG resources will be included as a consideration in on-going budgeting evaluations and as a contingency under potential greenhouse gas regulation. It should be noted that some of the landfills included in the 30 MW potential are currently flaring their landfill gas. These landfills offer minimal opportunities to offset CO_2 emissions.

NaS Batteries. This technology was eliminated from second level pre-screening based on high cost and the development status of the technology.

Solar. Dish/Sterling Engine technology was excluded based on cost.

Animal Waste. Animal waste generation technologies were eliminated from second level pre-screening based on high capital and operating costs. Therefore, no additional evaluation of this technology class was pursued. However, this technology remains an on-going consideration for contingency planning due to the equivalent CO_2 offsets provided by converting animal waste into a syngas for either flaring or electric generation.

Based on the above discussions, Table 8 below indicates the technologies passed to Ventyx for optimization modeling. In addition to these new resource alternatives, Ventyx was provided options for coal retirements and for conversion of Montrose Station to utilize biomass.

Table 8: Technologies Modeled In Second Level Of Pre-Screening

Combined Cycle	Supercritical Pulverized Coal with and without Carbon Capture and Sequestration (CCS)	Circulating Fluidized Bed Combustion
Integrated Gasification Combined Cycle (IGCC) with and without Carbon Capture and Sequestration (CCS)	Combustion Turbines (CT's)	Nuclear
Wind	Compressed Air Energy Storage (CAES)	Molten Carbonate Fuel Cells
Solar Parabolic Trough	Photovoltaic Flat Plate	Microturbines
Biomass Alternatives	DSM Programs	Energy Efficiency Programs

As noted above, additional discussion of the Ventyx optimization modeling is included in Volume 6, Integrated Analysis and the complete Ventyx report is attached in Appendix 4.G.

3.2.4 TECHNOLOGIES ELIMINATED AFTER SECOND LEVEL PRE-SCREENING

Pursuant to Rule 22.040 (2) (C) technologies that were eliminated from Integrated Analysis after the second level of pre-screening are discussed below with a brief explanation of the reason for exclusion:

Circulating Fluidized Bed Combustion

Circulating Fluidized Bed Combustion was included in the second level of pre-screening but this technology was not selected in the Ventyx optimization modeling. Therefore, no additional evaluation of this technology class was pursued.

Compressed Air Energy Storage (CAES). CAES was included in the Ventyx modeling, but was not selected by the optimization modeling. Therefore, no additional evaluation of this class of technology was pursued. Energy storage would normally have been excluded from the second level of pre-screening based on the first level pre-screen rankings. Even though pre-screening results showed high capital and operating costs for this technology, it was included in the Ventyx modeling due to the possibility for high renewable generation requirements under potential Renewable Portfolio Standards (RPS). Under such requirements, the portfolio value of energy storage is expected to increase. The Ventyx results did not demonstrate adequate value for energy storage.

Molten Carbonate Fuel Cells. Molten Carbonate Fuel Cells were included in the second level of pre-screening but were not selected by the optimization model. Therefore, no additional evaluation of this technology class was pursued.

Microturbines. Microturbines were included in the second level of pre-screening but were not selected by the optimization model. Therefore, no additional evaluation of this technology class was pursued.

Solar. Solar Parabolic Trough and Photovoltaic Flat Plate generation technologies were included in the second level of pre-screening but were not selected by the optimization model. However, under a proposed ballot initiative in Missouri, solar generation is included as a required resource. Therefore, due to the low level of solar generation required in the Missouri ballot initiative, Photovoltaic Flat Plate generation was moved to Integrated Analysis. Solar Parabolic Trough was not further evaluated.

Biomass Alternatives. Biomass technologies were included in second level pre-screening. Four alternatives were considered based on potential retrofits of the Montrose units and the use of new biomass Fluidized Bed installations at the Montrose site. The alternatives included:

1. The installation of new fuel handling equipment to allow co-firing up to a 10% blend of biomass/coal. A higher blend level in existing boilers require substantial retrofit costs, limit unit capacity and performance and have an adverse effect on the overall cost of production.

2. Boiler modifications to allow 50% co-firing. This alternative is generally preferred to a retrofit to burn 100% biomass due to the issues discussed above. In addition, the availability of biomass feed stock is expected to limit the quantity of reliable supplies of biomass.

3. Boiler modifications to allow 100% firing with biomass. Although this alternative was included in the second level of pre-screening, the availability of biomass feed stock may prohibit this alternative from consideration.

4. The installation of a new biomass Fluidized Bed generating unit to accommodate 100% firing of biomass. This alternative eliminates many of the operating concerns associated with burning high levels of biomass in boilers not specifically designed for biomass fuel. An adequate supply of fuel is assumed to be available for this alternative based on the unit size of 75 MW's as provided by EPRI Tag ®.

The second level of pre-screening did select the Montrose retrofit for 100% biomass co-firing under the scenario that included high CO_2 pricing, high load growth, high coal prices and high natural gas pricing. In this scenario, the optimization model selected the Montrose retrofit in 2032, the last year of the planning horizon. Due to the late installation date and the unlikely combination of high costs for multiple uncertainties (e.g., we would not expect high CO_2 to coincide with high coal pricing), this alternative was not carried over to Integrated Analysis. The alternative of biomass generation will, however, be a consideration for contingency plans under highly restrictive CO_2 regulation. Sections 3.2.3 and 3.2.4 above satisfy Rule 22.040 (9) (A) 3. as specified in 4 CSR 22.040, Supply-Side Analysis.

3.2.5 TECHNOLOGIES MOVED TO INTEGRATED ANALYSIS

Based on the findings of both pre-screening evaluations, Table 9 below indicates the technologies moved to Integrated Analysis.

Table 9: Integrated Analysis Candidate Technologies

Combined Cycle	Supercritical Pulverized Coal with and without Carbon Capture and Sequestration (CCS)	Nuclear
Integrated Gasification Combined Cycle (IGCC) with and without Carbon Capture and Sequestration (CCS)	Combustion Turbines (CT's)	Energy Efficiency Programs
Wind	Photovoltaic Flat Plate	Biomass Alternatives
CCS on Existing Coal Units	DSM Programs	

In addition, a generic coal retirement was included in Integrated Analysis. Additional details are found in Section 8.4.

Note that Table 9 satisfies requirement 22.040 (9) (A) 2. as specified in 4 CSR 22.040, Supply-Side Analysis.

SECTION 4: ENVIRONMENTAL COSTS INCLUDED IN UTILITY COSTS

As discussed in Section 3.2 above, one component of Utility Cost is the environmental cost associated with current regulations. The cost of compliance for existing environmental regulations are already included in EPRI Tag ® estimates for the installed capital cost and fixed and variable O&M. These estimates do not include emission allowance pricing related to CAMR and CAIR. Therefore, KCP&L includes the estimated emission allowance costs for CAMR and CAIR as part of the Utility Cost for each technology.

4.1 CAMR UTILITY AND PROBABLE ENVIRONMENTAL COST

A recent court ruling vacated the EPA's CAMR rule and returned the rule to the EPA for further rulemaking. Rather than the original cap and trade program, a revised CAMR could potentially require all coal fired generating units to achieve Maximum Achievable Control Technology (MACT) for mercury removal. The capital and operating costs of technologies evaluated in pre-screening include the cost of controls for mercury. For mercury, the known and anticipated technologies for mercury reduction include injection of a sorbent in conjunction with a collection device such as a baghouse and/or SO_2 scrubber. This removal technology is anticipated to meet MACT standards. New technologies included in the pre-screening already include the costs associated with this equipment and the sorbent usage, therefore, potential future rulemaking for mercury control is not expected to increase the cost of new technologies evaluated in this IRP.

The requirement to include two levels of mitigation above current regulation, as specified in IRP Rule 22.040 (2) (B) 2 is assumed to be covered by the range of forecasted allowance prices. Although a cap and trade market may not be in place under potential future rulemaking for mercury control, KCP&L believes the range of allowance price forecasts adequately captures the potential cost of future potential rulemaking.

Because CAMR is assumed under "utility cost", the application of subjective probabilities as required under the IRP rules for Probable Environmental Costs are not applicable.

4.2 CAIR (SO_2 & NO_x) UTILITY AND PROBABLE ENVIRONMENTAL COST

As noted above, new technologies are already priced with BACT emission controls, which are anticipated to account for any foreseeable changes in this regulation. The range of allowance price forecasts is assumed to cover the potential cost of potential future rulemaking for SO2 and NOx emissions. Therefore, no additional Probable Environmental Costs are assumed to apply for control of SO_2 and NO_x because these potential future costs are already captured in the Utility Cost evaluations.

Because CAMR is assumed under "utility cost", the application of subjective probabilities as required under the IRP rules for Probable Environmental Costs are not applicable.

SECTION 5: PROBABLE ENVIRONMENTAL COSTS

Rule 22.040 (2) (B) defines Probable Environmental Costs as the cost to comply with additional environmental laws or regulations that, in the judgment of utility decision-makers, may be imposed at some point in the planning horizon. A detailed narrative review of environmental regulations and future potential changes in regulations is included in the attached Appendix 4.B.2. Based on this review, five (5) potential new environmental laws, regulations or restrictions have been identified as follows:

1. Greenhouse gas restrictions in the form of a cap and trade market
2. Requirements to landfill all solid combustion by-products
3. The addition of cooling towers and fish impingement protection
4. Potential need to add control for zebra mussels
5. "Other" air emissions

KCP&L also estimated the Probable Environmental Cost impacts for existing generating units. The cost impacts for the five (5) potential new environmental laws, regulations or restrictions for each of KCP&L's existing units are included in the attached Appendix 4.D.5. A description of the five (5) restrictions and the cost of compliance for each is discussed below. Also included in each description pursuant to KCP&L's requested waiver and the granted variance described in "Staff Recommendation To Grant Variances With Conditions", Case No. EE-2008-0034, dated March 7, 2008, Item 7, is an explanation for the rationale used in the level of mitigation applied.

5.1 <u>COMBUSTION BY-PRODUCT RESTRICTIONS</u>

This Probable Environmental Cost covers the potential requirement to landfill all coal combustion by-products. The application of two levels of mitigation does not apply in this case. The requirement will either not occur or will require all coal combustion by-products to be landfilled. The subjective probability of this restriction is estimated at 50% over the 20-year planning horizon.

For new technologies included in the pre-screening, the cost of landfill construction is included in the EPRI technology cost. The cost associated with this potential regulation is therefore based on the estimated operating costs for a landfill of ** [redacted] ** in 2007 $'s (see Appendix 4.B.3 for calculations). Under the assumed 50% probability of implementation, the expected Probable Environmental Cost is ** [redacted] **.

For existing plants, the cost impacts are shown in Appendix 4.D.1. The cost for existing plants includes the cost to construct a new landfill if additional landfill space is required for this potential future change in regulation.

5.2 WATER RELATED RESTRICTIONS (COOLING TOWERS & FISH IMPINGEMENT CONTROL)

This potential regulation is based on the existing Clean Water Act Sections (316 (a) & (b)) and would require cooling tower installations to reduce temperature impacts on sources of circulating cooling water. It also would include installing fish impingement protection. Similar to combustion by-product regulation, two levels of mitigation are not expected. Cooling towers and fish protection will either be required or will not be required. KCP&L assumes 100% probability that this requirement will be implemented within the 20-year planning horizon.

EPRI's installed cost used to value technologies for pre-screening includes the cost of cooling towers and fish protection. Therefore for pre-screening purposes, the cost of this potential regulation is already included in the base Utility Cost and does not impact the Probable Environmental Cost of new technologies.

For existing plants, the cost impacts are shown in Appendix 4.D.2.

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5.3 POTENTIAL FUTURE AIR EMISSION REGULATIONS

Potential future regulations include possible reductions in emissions of lead, Volatile Organic Compounds (VOCs), Hazardous Air Pollutants (HAPs) and other air emissions. Given the wide range of items included in this category, KCP&L assumed a proxy for the cost of increased regulations. KCP&L applied the cost of cleaning coal prior to combustion as a representative cost associated with controlling these potential additional air emissions. The cost was projected on a dollar per mmbtu basis and is applied to all coal-fired technologies. The projected delivered cost from a previous coal-cleaning pilot project was ** [redacted] ** (current year $). If coal-cleaning becomes a required regulation, it is expected that economies of scale would reduce the cost of cleaning by an estimated 50%. The price estimate was escalated at 2.5% per year over the planning horizon. KCP&L applied the average price of the escalated stream of costs over the 20-year planning horizon to calculate the cost increase associated with this requirement. The cost impact of coal-cleaning was then developed based on $/MWh for the specific heat rate of each impacted technology.

The subjective probability of increased control is estimated at 50% over the 20-year planning horizon. Therefore the expected value of the probable environmental cost is 50% of the total cost impact calculated by the above process. Calculation of this cost adder is shown in Appendix 4.B.3.

For existing plants, the cost impacts are shown in Appendix 4.D.3.

5.4 ZEBRA MUSSELS

Although not an environmental regulation, KCP&L includes the potential cost of controlling zebra mussels in its calculation of probable environmental costs. This cost is added to generating units requiring inlet cooling water. The cost associated with this potential hazard is based on installing and operating a chlorination system and is estimated to be **[redacted]** in 2007 $'s. Under the assumed 50% probability of implementation, the expected Probable Environmental Cost is **[redacted]**. The detailed cost estimate is attached in Appendix 4.B.3.

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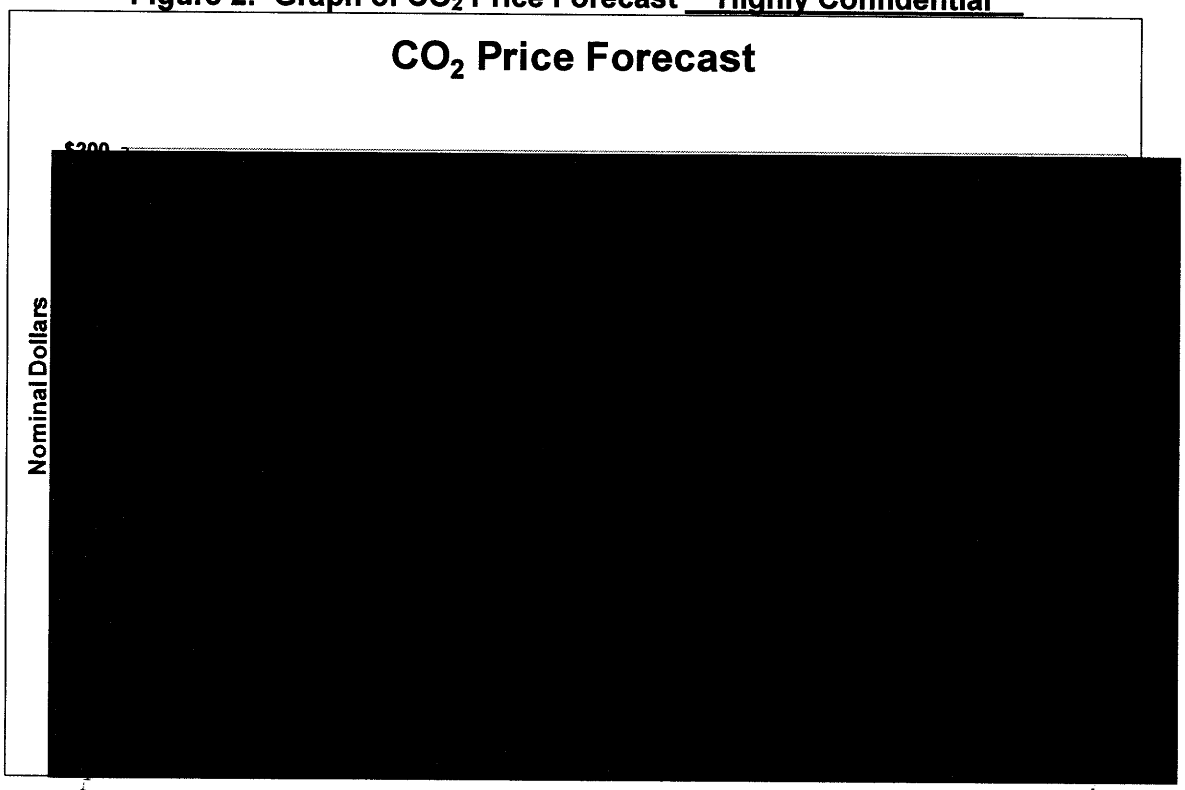
For existing plants, the cost impacts are shown in Appendix 4.D.4.

5.5 GREENHOUSE GAS RESTRICTIONS

For pre-screening purposes, the associated Probable Environmental Cost was based on the assumption of a cap and trade market for greenhouse gas emissions. It was further assumed that allowances would be available as needed.

The mitigation levels can include the timing of restrictions, the level of available allowances, the form of restrictions (e.g., a pure tax Vs cap and trade), the price of emissions allowances and the value of safety-valve pricing (if any). For satisfying the requirements of the IRP, KCP&L assumes that two levels of mitigation include restrictions starting in 2012 under a cap and trade market. The mid-price forecast was used to reflect the expected second mitigation level. It was also assumed that the cost of CO_2 allowances would apply to each metric ton emitted. KCP&L projects a 100% likelihood that greenhouse gas restrictions will be in place during the 20-year planning horizon. A graphical representation of the low, mid, and high forecasts is shown in Figure 2 below. To calculate the probable environmental cost for pre-screening, KCP&L applied the mid-level price forecast. A detailed description of the development of the CO_2 and other key emission allowance price forecasts is included in Appendix 4.C.

Figure 2: Graph of CO_2 Price Forecast **<u>** Highly Confidential **</u>**



[redacted]

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SECTION 6: FUEL PRICE FORECASTS

KCP&L employed a consensus forecasting approach to develop the range of price forecasts for each fuel type. The Commission granted KCP&L a waiver under "Order Granting Kansas City Power and Light Company's Request for Waivers" (Order), Case No. EE-2008-0034, dated October 5, 2007, Attachment B, Item 1, regarding this approach to fuel price forecasting. Details of the consensus forecasting approach and development of the fuel price forecasts are included in Appendix 4.C. Separate discussions are included for each fuel type including the data utilized to develop each price forecast. Additional fuel information required by 22.040 (8) (A) is also included in the appendices. Data for key fuel-types are included as noted below:

1. "Consensus" Forecast Modeling Approach—Appendix 4.C.1
2. Natural Gas—Appendix 4.C.2
3. Coal—Appendix 4.C.3
4. Crude Oil—Appendix 4.C.4
5. Nuclear Fuel—Appendix 4.C.5

Table 10 and Table 11 below summarizes the source forecasts utilized to develop KCP&L's price forecasts for fuels.

Table 10: Data Sources for Coal, Natural Gas and Oil Forecasts

	Fuels		
Forecast Source	**Coal**	**Natural Gas**	**Oil**
EIA	x	x	x
Energy Ventures	x	x	x
Global Insight		x	x
Hill & Assoc	x		
JD Energy	x		
NYMEX		x	x
PIRA		x	x

Table 11: Data Source for Nuclear Fuel Price Forecasts

Forecast Source	Nuclear Fuel			
	Mine	Conversion	Enrichment	Fabrication
	U_3O_8	UF_6	SWU	Fuel Rod
ERI	x	x	x	x

Results of the fuel price forecast analysis for natural gas, fuel oil and coal are shown in Table 12 below. Results of the nuclear price forecast analysis are shown in Table 13.

Table 12: Fuel Price Forecast ** Highly Confidential **

FUEL PRICE FORECAST	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
[redacted]													

FUEL PRICE FORECAST	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
[redacted]													

Table 13: Nuclear Fuel Price Forecast ** Highly Confidential **

FUEL PRICE FORECAST	2007	2008	2009	2010	2011	2012	2013
[redacted]							

FUEL PRICE FORECAST	2014	2015	2016	2017	2018	2019	2020
[redacted]							

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SECTION 7: EMISSIONS ALLOWANCE PRICE FORECAST

Emission allowance price projections were developed using the consensus forecasting approach applied for the fuel price forecasts. The Commission granted KCP&L a waiver under the Order, Appendix B, Item 1, regarding this approach to emissions allowance price forecasting. Forecasts were developed for SO_2, NO_x, Seasonal NO_x, mercury and CO_2. As previously discussed, the cost of SO_2, NO_x, Seasonal NO_x, and mercury emissions are included as part of the "Utility Costs". Costs are applied based on projections of cap and trade markets under the CAIR and CAMR rules as released by the U.S. Environmental Protection Agency (EPA) prior to potential changes resulting from court actions. The potential cost of CO_2 emissions is included as part of the "Probable Environmental Costs" and is based on the mid-level allowance price.

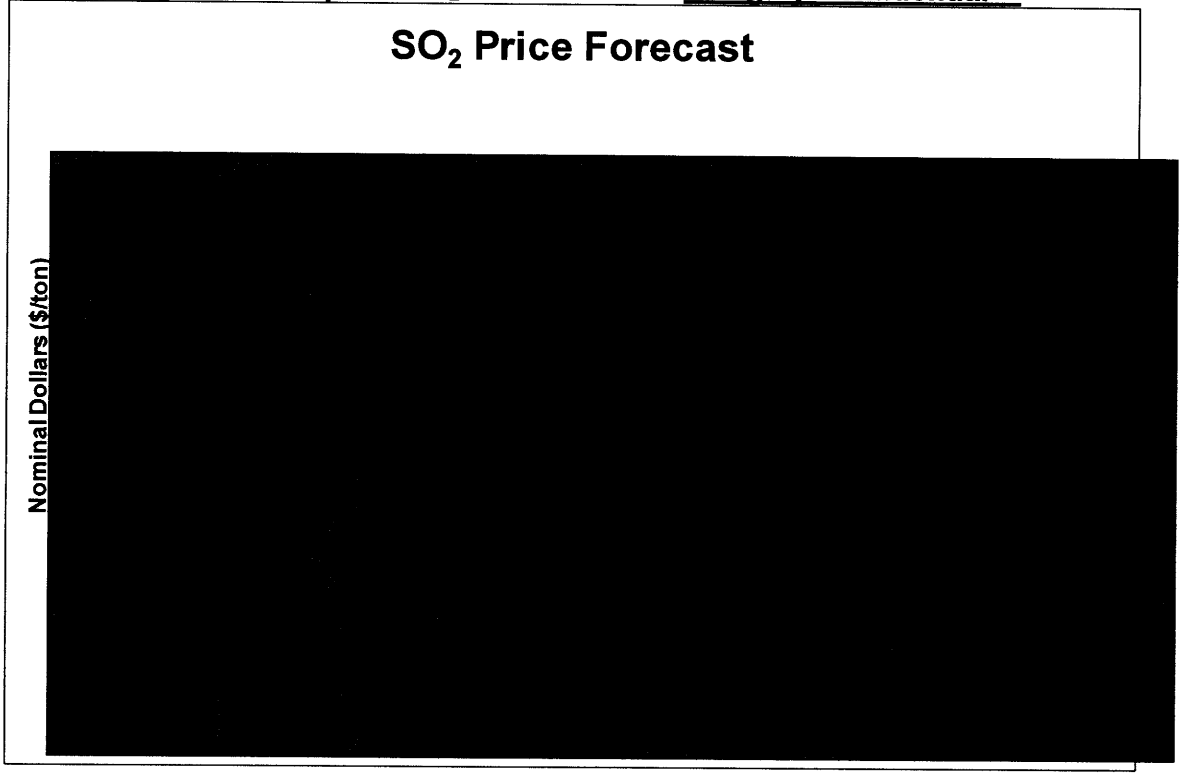
Data sources supporting each emission price forecast varied depending on the particular emission and the available market forecasts for that particular emission. Table 14 below summarizes the source forecasts utilized to develop KCP&L's price forecasts for emissions and fuels. Source references for the specific forecasts applied are included in the list of references shown in Appendix 4.C.

Table 14: Data Sources for Emission Price Forecasts

	Emission				
Forecast Source	**SO_2**	**Annual NO_x**	**Seasonal NO_x**	**Hg**	**CO_2**
[illegible]					x
EIA					x
Energy Ventures	x	x	x	x	
EPA	x	x		x	
EPRI					x
Greenmont	x	x	x	x	
JD Energy	x	x	x		
PIRA	x	x	x	x	x
Synapse					x

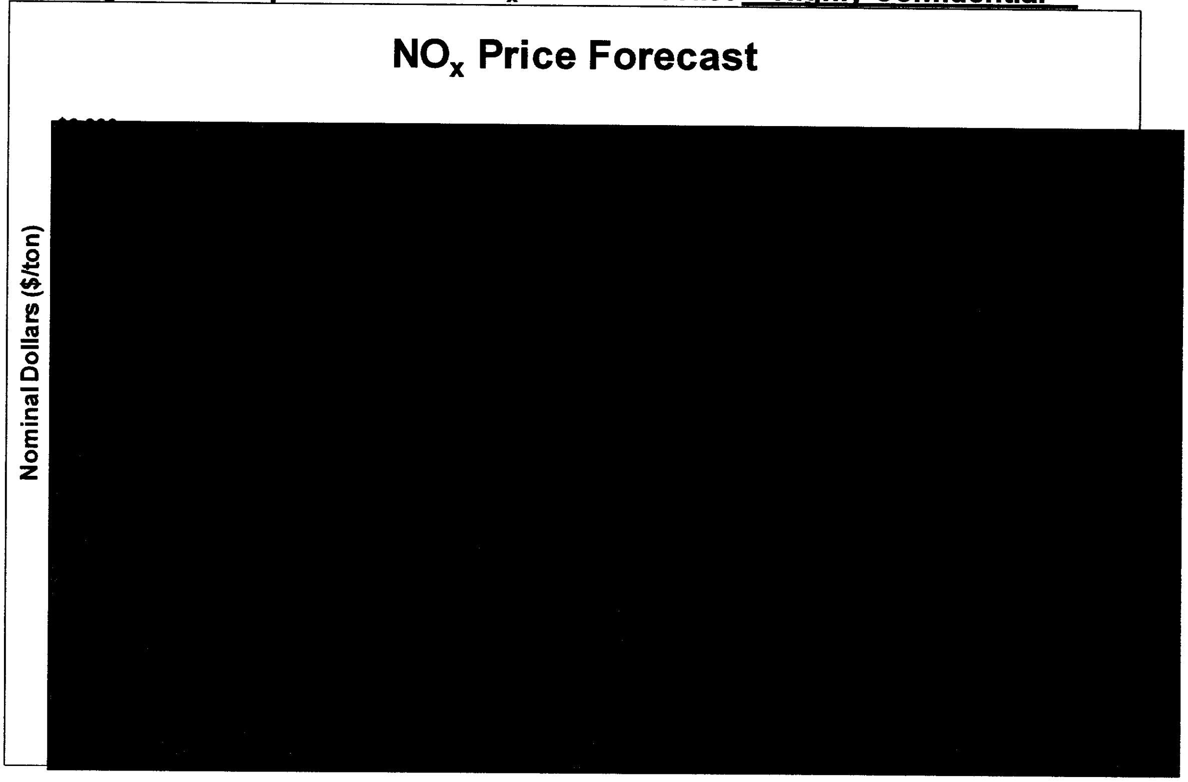
A graphical representation of the low, mid & high forecasts are shown in Figure 3 through Figure 6 below.

Figure 3: Graph of SO_2 Price Forecast __ Highly Confidential **__**



[redacted]

Figure 4: Graph of Annual NO_x Price Forecast <u> Highly Confidential **</u>**



[redacted]

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Figure 5: Graph of Seasonal NO_x Price Forecast **<u>** Highly Confidential **</u>**

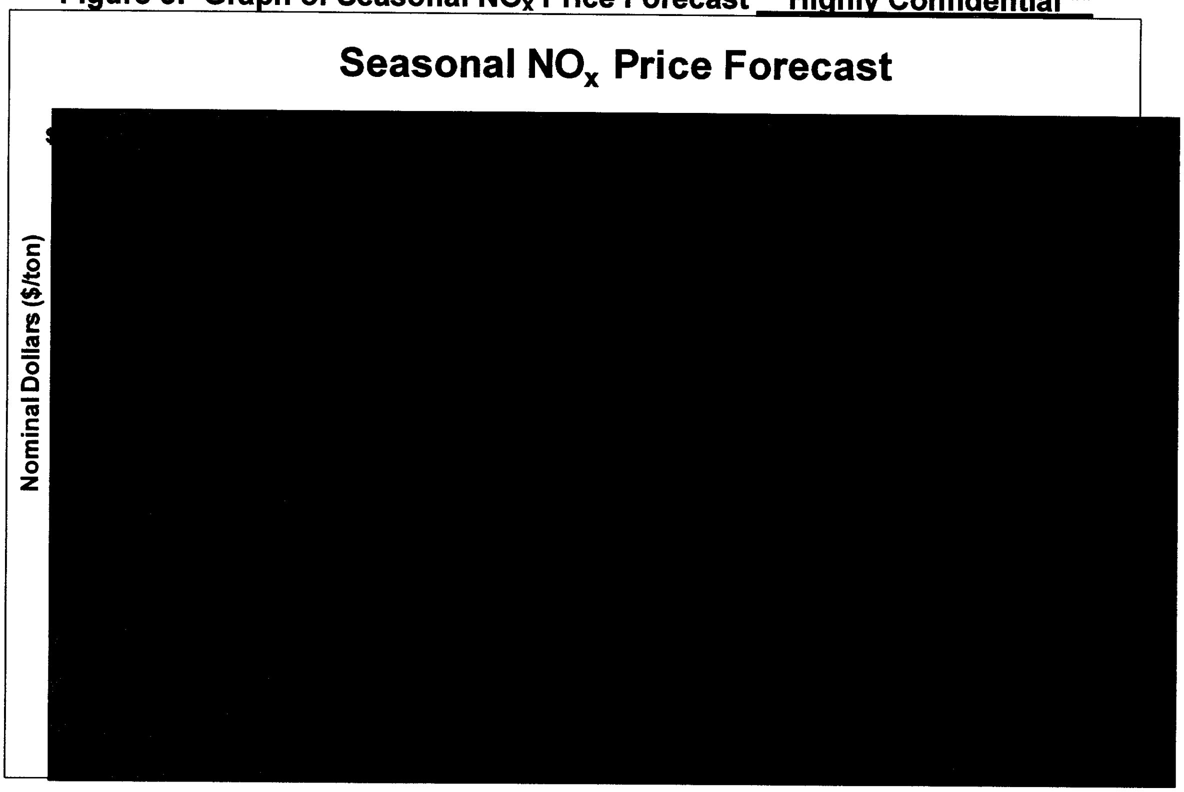

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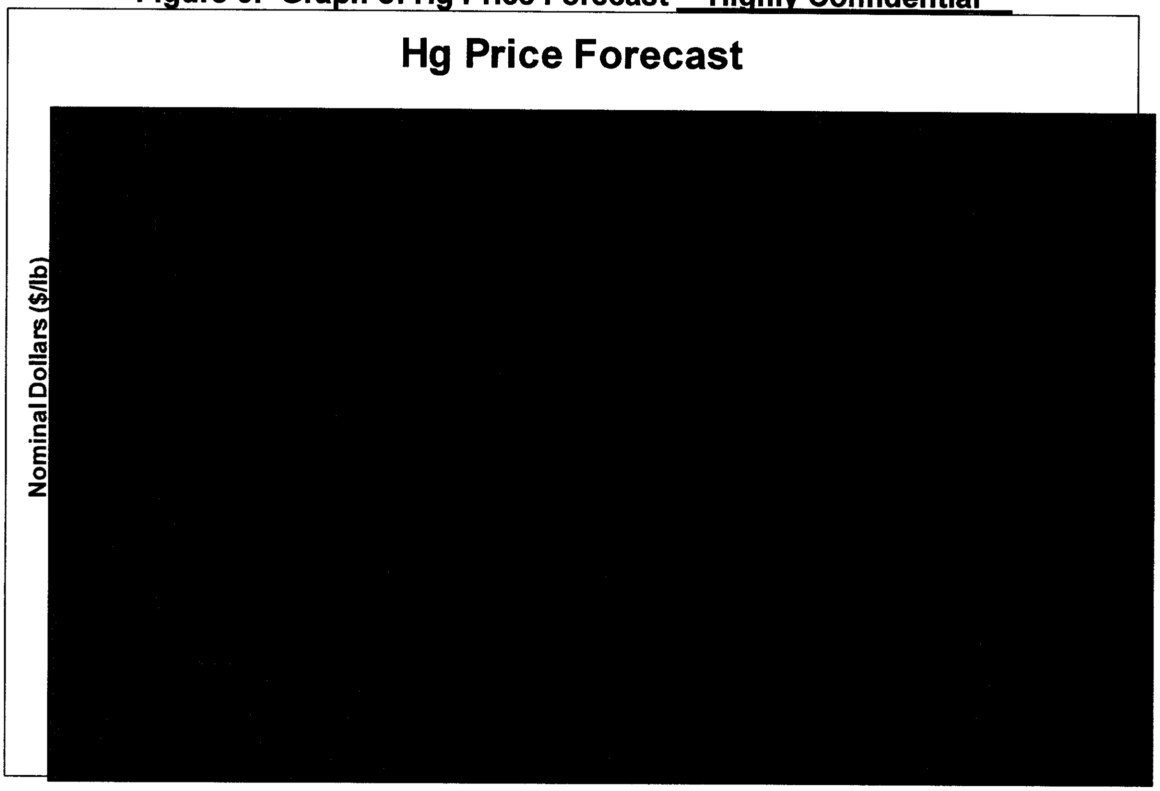
Figure 6: Graph of Hg Price Forecast __ Highly Confidential **__**



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SECTION 8: EVALUATION OF EXISTING GENERATING FACILITIES

To address Rules 22.040 (1) and 22.040 (4), KCP&L pursued four evaluation efforts as described below.

1. Black & Veatch (B&V) was retained to evaluate projects to increase the efficiency of our existing units and therefore reduce KCP&L energy use.

2. Plant and Engineering staff members conducted evaluations to identify anticipated future cost to maintain and potentially enhance the performance of existing generation facilities. These evaluations are referred to as the Life Assessment and Management Program (LAMP).

3. Environmental enhancements of existing facilities.

4. Retirement scenarios (generic coal retirements).

8.1 PLANT EFFICIENCY STUDY

KCP&L retained Black & Veatch (B&V) to study potential efficiency improvement projects on existing generating facilities. Evaluations started with meetings at each facility to identify potential efficiency improvement projects. B&V also provided a list of typically available projects for review, comments and recommendations from plant personnel. This effort resulted in identifying over 162 potential projects.

B&V personnel then developed benefit/cost measures using KCP&L's Economic Value Added (EVA) model. In addition to the EVA values, each project was evaluated based on the amount of CO_2 reduced. The priority of each project was then established based on EVA results, projected CO_2 reductions and the total cost per ton of CO_2 reduced. The B&V final report, "CO_2 – Plant Efficiency Improvement Assessment" is included as Appendix 4.D.6.

Of the original 162 potential projects identified, 59 projects were dropped from further consideration because they were either not feasible, the resulting performance improvements were unclear, or the projects were not expected to provide a defined efficiency improvement and / or the associated defined CO_2 reduction.

For IRP planning purposes, it was assumed that the efficiency projects with positive benefit-cost test results would be completed under routine capital budget processes.

8.2 PLANT LIFE ASSESSMENT AND MANAGEMENT PLAN (LAMP)

In response to Rule 22.040 (1), which requires consideration of existing plant refurbishment, KCP&L performed an internal review of long-term plant equipment needs. The review was based on the LAMP process as described below. The results show the long-term capital and maintenance items and costs required to maintain unit performance over the IRP planning timeline.

8.2.1 HISTORY

In the late 1980's, the Life Assessment and Management Program (LAMP) was developed for the purpose of identifying, evaluating, and recommending improvements and special maintenance requirements necessary for continued reliable operation of KCP&L coal-fired generating units. The LAMP program objectives included the following activities:

1. Identify and recommend unit requirements associated with future operating plans
2. Identify and recommend areas of improvement and special maintenance requirements necessary to extend the operating life of each unit
3. Identify and recommend areas of improvement to achieve any or all of the following goals:
    a. Capacity

b. Performance

c. Reliability/Availability

d. Safety/ Environmental

e. Operational Changes

4. Provide a basis for identification and prevention of major component failure, and costly interruptions associated with continued use of existing equipment

5. Provide the tools for managing and protecting remaining life of critical components/assets.

A list of critical assets was developed and included in the LAMP program document. Critical assets include pieces of equipment that if failure occurred would result in high cost or catastrophic, long-term damage to the capability of the generating unit. In general, critical assets were high cost and long lead time items. The inspections and maintenance required for each asset were indentified from Service Bulletins issued by Original Equipment Manufacturers (OEMs), Technical Information Letters and other OEM supplied documents. In addition, inspections were generated based on industry experience and engineering firm recommendations. Experience gained from internal failure analysis also prompted scheduled critical equipment inspections at all stations.

In 2005, the LAMP program was updated to include the combustion turbines and all of the testing was incorporated into the EMPAC system. EMPAC is the computer-based work management system used by KCP&L's Supply Division to generate and track needed maintenance work orders. The program philosophy remained the same, however program administration was changed to reflect and utilize the generating stations' work order software. By using EMPAC, all of the work orders required for testing and associated craft resources could be identified and planned prior to an outage.

8.2.2 LAMP PROCESS

Because all LAMP tests have been incorporated in EMPAC, the associated work orders are generated automatically that provide data on the status of any given procedure for each asset that qualifies as a LAMP item.

The LAMP tests are coded when they are put in EMPAC with information detailing work to be performed, frequency, station status required for performing the work (running or shutdown), and personnel required to perform the work. When a work order is generated, it goes to the station planner who determines when the work will be completed (for example, during the next scheduled outage, or the next time the asset is shutdown) and coded by the planner to ensure proper placement. A responsible engineer is assigned to each work order. When the work is completed, the engineer places a note in the work order and changes the work order status to complete. The planner will then close the work order.

The work order note contains a brief statement about the LAMP testing results and what is recommended (continue on current inspection schedule or repairs made under work order number). The note may reference a Boiler Outage Workstation worksheet that contains more information. There is also a folder that test documentation may be attached to in the work order.

8.2.3 CURRENT STATUS

Meetings were recently completed to review LAMP tests with appropriate KCP&L engineering groups. The groups reviewed lists of critical assets for each station. Updates were made to the tests, frequencies, responsible groups, next due date and resources required for completion of testing. All of the additions and changes identified are being input into EMPAC. Additionally, LAMP work to be performed during the 2008 – 2010 schedule outages were identified.

The life assessment and maintenance program (LAMP) is a very dynamic program at KCP&L. Staying current with research on advanced methods for assessing equipment condition nondestructively and accurately is an ongoing goal. Networking with other utilities through conferences and papers, staying abreast with applicable technical service bulletins, and KCPL's active involvement with EPRI are examples being employed to strengthen the LAMP program.

An example of the dynamic nature of the LAMP program is a recent technical service bulletin (TSB) issued describing a structural failure at another utility of a spray dryer absorber (SDA) chamber after 22 years of service. The TSB described the incident in detail and made recommendations for identifying similar problems. Because KCPL has a SDA at the Hawthorn plant, a work order was submitted to conduct ultrasonic thickness (UT) measurements to assess wall thickness. SDA assessment has now been incorporated as a routine test procedure in the LAMP program. Additionally, flow accelerated corrosion (FAC) testing is now being performed in areas of high probability in all KCPL plants and this is also new to the LAMP and will be ongoing.

In June, 2008, KCP&L will be utilizing Predictive Maintenance Analysis (PdMA) motor reliability software, available on the KCP&L network. This new software will provide enhanced tracking capability of motor operating history. Prior to utilizing PdMA, each plant had a stand-alone program where the motor data resided, making data analysis and trending cumbersome for the engineering group responsible for maintenance analysis. The use of company-wide networked software allows for optimization of critical motor operation, inspection, and maintenance procedures and intervals. Therefore, critical motors won't be taken out of service unnecessarily, and can continue running which results in maintenance cost reductions.

Standardization of transformer oil analysis with S.D. Myers, Inc., is another LAMP procedure that will be put into place in the very near future. The goal is to expand transformer testing to include furan content, corrosive sulfur, dissolved metals and other tests in order to better diagnose the state of transformers. The goal is to extend the life of transformers to 50+ years of reliable operation. At present, La Cygne Station is utilizing S.D. Myers, Inc. for oil testing and diagnostics. S.D. Myers provides access to their LAB online program, which enables customers to review transformer maintenance test data on a regular basis. This program provides current maintenance information which aids in prolonging the life of transformers.

All other company transformers are routinely checked by oil analysis performed by the company's Central Laboratory. In addition to oil analysis, transformers are being fitted with on line Dissolved Gas Analyzers (DGA), insulation breakdown monitors and bushing monitors. The analyzers and electronic monitors will provide early warning of progressive aging problems so that corrective action can be taken to avoid major failures.

The testing to determine the integrity of the cathodic protection (CP) systems at each of the plants was identified as a LAMP procedure that required additional attention. Because this subject is very complex in nature, Matco Associates Inc. was selected to conduct CP evaluations of the CP systems and protected assets at the KCP&L Montrose, Hawthorn, La Cygne and Iatan plants. It is the intent of these evaluations to assess the present overall efficiency of the CP systems at each facility, provide recommendations as required to facilitate repairs, and to gain enough familiarity with the respective facilities to allow KCP&L to conduct adequate periodic evaluations of CP efficiency on a routine basis. A corrosion group manager who is a certified CP technologist, a CP technician and others from their technical staff, as required for the project, will be conducting the on-site work.

8.2.4 LAMP SUMMARY AND RESULTS

Continued progress is being made to enhance the LAMP program. KCPL is fully committed to make further improvements in data collection and analysis by incorporating new life assessment tools that can be used not only to identify the viability of older plant components, but also to improve the operation, efficiency and performance of existing units.

Current schedules of identified LAMP projects including project costs are shown in Table 15 through Table 23. Note that all costs are total dollars, not KCP&L share. The projects listed are anticipated to be included under routine capital and operating budgets. For resource planning, the LAMP results serve to identify high cost projects that may impact future retirement decisions. For the generic coal retirement modeled in the IRP, the appropriate LAMP costs were included in alternative resource plans showing continued operation of the modeled unit.

Table 15: LAMP Projects for Hawthorn – Total Cost ($ 1000's) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					

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Table 16: LAMP Projects for Iatan 1 – Total Cost ($ 1000's) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					

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Table 17: LAMP Projects for LaCygne-1 – Total Cost (1000 $'s) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					

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Table 18: LAMP Projects for LaCygne-2 – Total Cost (1000 $'s) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					

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Table 19: LAMP Projects for LaCygne Common – Total Cost (1000 $'s) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					

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Table 20: LAMP Projects for Montrose - 1 – Total Cost (1000 $'s) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					

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Table 21: LAMP Projects for Montrose - 2 – Total Cost (1000 $'s) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					
M2 Generator Upgrade	[redacted]																				
[redacted]																					

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Table 22: LAMP Projects for Montrose - 3 – Total Cost (1000 $'s) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					

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Table 23: LAMP Projects for Montrose Common – Total Cost (1000 $'s) ** Highly Confidential **

Project Name	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
[redacted]																					

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8.3 ENVIRONMENTAL ENHANCEMENTS

Pursuant to Rule 22.040 (1), KCP&L has current environmental expectations that LaCygne Station will require installation of a baghouse and FGD on Unit 1, and particulate matter controls, NOx controls and FGD on Unit 2. Montrose Station will eventually be required to install similar emission control equipment. The remainder of KCP&L's coal-fired generation will have BACT controls within the current 2008-2012 planning period. Budgeted costs for these enhancements are included in the Base case for MIDAS modeling for Integrated and Risk Analysis.

Longer term, additional costs for potential environmental enhancements on existing units are assumed to be captured in the Probable Environmental Costs (PEC) developed for existing units as part of the IRP evaluation. The cost impacts for existing units are shown in Appendix 4.D.5.

8.4 GENERIC COAL RETIREMENT SCENARIOS

For the IRP, KCP&L evaluated a generic coal retirement. For modeling purposes, this required one of our existing units to be "retired" or removed from the portfolio. Modeled savings included avoided environmental retrofits, reduced capital spending in the years prior to retirement, and avoiding the cost of the long-term LAMP projects described in Section 8.2 above. In addition, due to the reduced capital spending prior to retirement, deteriorating unit performance was included in the modeling. These costs were assumed to adequately reflect the costs associated with a potential unit retirement. The generic operating impacts of a retirement decision are shown in Table 24 below for a proposed 2016 retirement. Results of modeling indicated that the generic coal retirement was not preferred without highly restrictive greenhouse gas regulation and high fuel pricing.

Table 24: Retirement Performance Impacts ** Highly Confidential **

Item	2009	2010	2011	2012	2013	2014	2015
[redacted]							

KCP&L anticipates a more definitive evaluation of retirement options under a future process called the Sustainable Resource Strategy (SRS). This process is anticipated to begin during the third quarter of 2008. That effort will provide a more robust and focused evaluation of retirement alternatives than offered in the IRP. Completion of the SRS is currently anticipated by mid 2009, which is expected to coincide with the required decision timeline for environmental retrofits on LaCygne station.

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SECTION 9: TRANSMISSION AND SUBSTATION CONDITION AND EFFICIENCY ASSESSMENT

Rules 22.040 (1) and 22.040 (7) require utilities to evaluate existing transmission and distribution facilities, and loss-reduction measures. Section 9: fulfills these requirements.

9.1 ECONOMICS OF TRANSMISSION AND DISTRIBUTION LOSS REDUCTION

9.1.1 TRANSFORMER LOSSES

In 2007, KCP&L analyzed its distribution transformer population base and purchasing practices to determine if lower losses would be a positive economic choice. This analysis is attached in Appendix 4.H. Department of Energy standards TP1, TSL2 and TSL4 loss levels were used as benchmarks for comparison. TP1 is the level of transformer efficiency that was adopted in the 2005 energy bill that utilities must meet or exceed by January 2007 to be in compliance. (TSL4 efficiencies are higher than TSL2, which is higher than TP1). These DOE proposed standards recommend that utilities obtain the TSL2 level by 2010 and the TSL4 level in the indeterminate future. Present EEI recommendations are that utilities change their buying practices to achieve TSL2 levels by 2009, and TSL4 levels by 2013. These dates have been supported by KCP&L.

An analysis of the existing distribution transformers installed on the KCP&L system indicates that;

1. All existing single phase and three phase distribution transformers are in compliance with TP1;
2. Nearly all single phase transformers are at TSL4 levels or higher based on the best total owning cost for KCP&L's system;
3. Currently, 96% of three phase transformers are TSL2 compliant, and;

4. Of those three phase transformers that are TSL2 compliant, 20% are TSL4 compliant, also based on best total owning cost as well.

After KCP&L completed the economic analysis above, the DOE came out with a new efficiency level which will be mandatory beginning in 2010. Once again in analyzing KCP&L's current transformer fleet it was found that the overwhelming majority of KCP&L's single phase transformers are 2010 compliant. A large majority of the existing three phase transformers are compliant as well. The decision was made in 2007 by KCP&L to:

1. Continue to purchase single phase transformers that are 2010 compliant, and;
2. Alter purchasing practices to buy only 2010 compliant three phase transformers.

Expected aggregate results of this purchase decision are savings of 7.4 MW of peak demand after 30 years.

Evaluations indicated it was not economic to replace existing non-compliant transformers (those transformers less efficient than 2010 standards) with 2010 units simply to gain efficiency. Instead of a system-wide program of replacements, non-compliant transformers will be replaced with 2010 compliant transformers when failures occur. A change out program was estimated to cost ** [redacted] ** and would provide a ** [redacted] ** load reduction only across the system peak with annual energy savings of less than ** [redacted] **. Compared to a supply-side alternative, the project would equate to installing a ** [redacted] ** resource with less than a 6% capacity factor.

9.1.2 LINE LOSSES

An additional strategy that also contributes to reduce demand as well as reduced carbon emissions is for utilities to find ways to minimize existing system losses. Many utilities like KCP&L are adopting the idea of building "Green Circuits", by the study, demonstration, and application of loss reduction technologies and measures.

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Electrical distribution systems losses typically range from 3% to 7%. Efficiency standards and carbon emission reduction requirements should lead utilities to consider their options for addressing distribution losses. Company material and construction Standards are developed to provide both load and economic efficiency to the distribution system. Design processes review both system operating requirements and economics. Improvements in material and changes in system cost factors result in improvements to both Standards and the Design process.

New or enabling technology advances help in achieving this:

Advances in modeling capabilities enable better loss estimation, identification of loss mitigating technologies and verification of improvements

Time stamped metering data provides information on end-use patterns and diversity factors and enables improved quantification of distribution losses

Also, communications and control capabilities create opportunities to implement precise voltage and var control algorithms to reduce line losses, transformer losses and lower end-use consumption and make automatic reconfiguration or looped operation feasible.

Feeder conductor replacement for the sole purpose of improving efficiency returns a negative 20-year NPV with assumed energy values of both $0.06/kWh and $0.10/kWh. Based on this finding, feeder conductor replacement is not an economic alternative to supply-side alternatives. <u>The cost of achieving the decrease in line losses exceeds the benefits obtained.</u> The two examples below summarize these findings. Both Case 1 and Case 2 are projected based on upgrading 1-mile of conductor.

Case 1: Replace #2 ACSR with 3/0 ACSR ([redacted] **)**

Losses (watts per hour) associated with each conductor are 7,383 watts for the #2 conductor and 2,652 watts for 3/0. The loss reduction on peak due to the difference in resistance between the two wire sizes is 4,733 watts. Annual

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Savings at **[redacted]**. The Net Present Values (NPV's) of the upgrade over a 20-year life at different energy values are **[redacted]**.

Case 2: Replace # 2 ACSR with 477 MCM

Apply the same assumptions and calculations as Case 1, except the 477MCM line has lower losses (489 watts) than the 3/0 conductor and the cost of replacing 1-mile of line is **[redacted]**. The resulting net present value at **[redacted]**.

9.2 TRANSMISSION

9.2.1 CONDITION AND EFFICIENCY ASSESSMENT

KCP&L has established processes to identify transmission assets with anticipated or demonstrated deficiencies related to age and condition. The replacement of equipment is addressed via the Asset Management process. Information on lines identified for significant maintenance (e.g., replacement of conductor or structures) is provided on an annual basis. Rebuilding or replacement of these lines is considered in annual transmission planning studies with the impact on system losses included in the analyses.

9.2.2 SUBSTATION CONDITION AND EFFICIENCY ASSESSMENT

Substation maintenance is scheduled to maximize reliability and functionality of substation equipment. Diagnostic tests and frequency are carefully selected to obtain meaningful data that can be used to predict and prevent failures. Many tests can be done with the equipment on-line. Infra-red scanning is an example. This is done to detect abnormal heating of equipment and connections that could lead to failure if not repaired. Corrective maintenance is scheduled based largely on diagnostic data, with the intent of restoring equipment to full functionality. Occasionally old equipment is no longer practical to repair and replacement is scheduled. As equipment is replaced

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and the system is developed, an emphasis is placed on reliability, efficiency and reduction of losses.

9.3 DISTRIBUTION SYSTEM CONDITION AND EFFICIENCY ASSESSMENT

KCP&L assesses the age and condition of its distribution system equipment via inspection, testing and equipment replacement programs, as described below.

9.3.1 CIRCUIT AND DEVICE INSPECTIONS

Circuits and Devices are inspected to protect public and worker safety and to address problems that might impact system reliability. This program includes inspection of all sub-transmission and distribution circuits having voltages in the range of 4kV to 34kV, as well as the poles, hardware and equipment on those circuits. Inspections will be incorporated as required to comply with final adoption of Proposed MPSC Rule 4 CSR 240-23.020. A small number of transformers will be replaced annually due to oil leaks or other visually detectable issues. When transformers are replaced, KCP&L uses high efficiency transformers. In addition, the inspection program includes annual inspections of all line capacitors. Any banks found to be inoperable are repaired or replaced, thus enabling the proper power factor correction function.

KCP&L has installed Distribution Automation equipment on portions of the Distribution System, including Underground Networks, Distribution Capacitors, and 34kV Reclosers. These systems are equipped with two-way communications and have intelligent sensors installed that allow for continuous, remote monitoring. These systems enable KCP&L to monitor the health of the equipment and perform condition-based inspections and maintenance.

9.3.2 MULTIPLE DEVICE INTERRUPTIONS

Devices or laterals experiencing multiple interruptions in a calendar year are designated for an engineering review. Corrective actions might include spot tree trimming, protective device additions, interrupting device coordination reviews, or other remedies.

9.3.3 (URD) CABLE REPLACEMENTS

Individual sections of single phase or three phase direct buried cable are replaced after two failures in a lifetime.

All or a subset of the cable sections in single phase or three phase direct buried cable laterals (i.e., fuse to normal open or fuse to end-of-circuit), are evaluated for replacement by application of a set of criteria for ranking replacement alternatives. An engineer will study the performance in more detail (as well as the performance of the lateral on the other side of the normal open if looped) in order to make a final determination as to how much cable (if any) will be replaced. This approach is at a more macro level than individual sections and addresses cable replacement at a neighborhood or subdivision level.

These replacements typically result in aluminum cable being replaced with more efficient copper cables.

9.3.4 DISTRIBUTION COMPONENT LIFE-CYCLE ANALYSIS

KCP&L is currently evaluating a more formal life cycle analysis process. Its purpose is to establish credible and defensible asset life cycle estimates, determine future spending requirements for all asset classes, and support efforts to fund the replacement and cost recovery of aging delivery infrastructure. As equipment is replaced and the system is developed, emphasis is placed on reliability, efficiency and reduction of losses. KCP&L is currently performing a Distribution System Inventory to gather data to be used in studies as part of the life cycle analysis process.

9.3.5 CONVERSION OF DUSK-TO-DAWN LIGHTING

KCP&L standard lighting is high-pressure sodium. Mercury vapor, fluorescent and incandescent lamps are obsolete types and are replaced with high-pressure sodium luminaries as they fail. KCP&L continually monitors development of more efficient lighting technology for trial applications.

9.4 DISTRIBUTION SYSTEM PLANNING

KCP&L assesses system capacity, efficiency and losses via seasonal distribution system planning studies.

9.4.1 ANNUAL DISTRIBUTION SYSTEM LOAD ANALYSIS AND SYSTEM PLANNING PROCESS

KCP&L records summer and winter peak load conditions (power, power factor, phase balance and voltage levels) at bulk and distribution substations. Power flow analyses are then performed using the distribution substation loads as input data.

An integral part of the distribution system load analysis process is the establishment of equipment ratings and/or loading limits. KCP&L evaluates transformer and conductor losses as part of the methodology used in establishing distribution equipment standards for subsequent application by distribution system planning engineers.

Computer models of the electric power delivery system are updated to include projected load magnitudes and updated equipment ratings on an annual basis. KCP&L performs seasonal planning studies for winter and summer peak conditions. Worst-case single-contingency failure scenarios are evaluated for all bulk subtransmission substations, 34kV subtransmission feeders, distribution substations, and distribution feeder circuits. These studies assist in evaluating system limitations requiring upgrades necessary to maintain adequate system capacity and reliability. The evaluation of distribution system losses and maintenance of adequate system voltage levels are included in these analyses.

Planning system upgrades to withstand single-contingency (N-1) outage conditions insures that load levels will remain within circuit capabilities for such events. Under normal conditions (the majority of the time) individual circuit elements operate at lower load levels with correspondingly lower losses.

9.4.2 2006 SYSTEM LOSS STUDY

During 2006, KCP&L evaluated its overall electric delivery system losses. The results of this study were derived from a comprehensive analysis of the KCP&L electric system for the calendar year 2004. The results of this study are being employed in system planning activities.

9.4.3 TRANSMISSION AND DISTRIBUTION SYSTEM ENGINEERING ANALYSIS

9.4.3.1 Distribution Engineering Modeling System

KCP&L utilizes SynerGEE modeling for distribution circuit analysis. Representations of the distribution circuits are installed in SynerGEE to perform analysis in order to ensure reliable, safe, and efficient operation of the distribution system. SynerGEE is used to perform the following types of analyses at KCP&L: Load Estimation, Power Flow, Protective Device Coordination, Fault Current, Phase Balancing, and Capacitor Placement. SynerGEE allows engineers to examine existing (and alternate or proposed circuit) configurations for over/under voltage/current, examine line losses, determine appropriate conductor sizing, and determine the optimal capacitor placement to reduce distribution losses. A separate cable derating program is utilized to analyze cable heating limits in order to maximize cable loading limits.

9.4.3.2 PSS/E System

KCP&L utilizes Siemens PTI's PSS/E software to evaluate Power Flow, Voltage Flicker and Capacitor Placement within the transmission and subtransmission system. Circuit models are utilized in PSS/E to perform these analyses in order to ensure reliable, safe, and efficient operation of the transmission system. PSS/E allows engineers to examine existing (and alternate or proposed) circuit configurations for over/under voltage/current, line losses, appropriate conductor sizing, and optimal capacitor placement configurations.

9.4.3.3 ASPEN System

KCP&L utilizes Siemens PSS/E and ASPEN, Inc. software to evaluate Fault Current and Protective Device Coordination within the transmission and subtransmission system. Circuit models are utilized in PSS/E and ASPEN to perform these analyses in order to ensure reliable and safe operation of the transmission system. PSS/E and ASPEN allows engineers to examine existing (and alternate or proposed) circuit configurations for maximum/minimum fault voltage/current and to develop appropriate protective device configurations and settings.

9.4.3.4 SCADA System

SCADA data is used to make system models more precisely reflect real system operation, therefore enabling better planning of the system.

9.4.4 TRANSFORMER REPLACEMENT FOR LOSS REDUCTION

KCP&L has previously evaluated the replacement of older, less efficient transformers for the specific purpose of loss reduction and found this approach not to be cost effective. Energy cost savings associated with reduced losses are dwarfed by the purchase price and change-out cost associated with transformer replacement.

9.4.5 COMMITMENT TO FUTURE EFFICIENCY INCREASES

KCP&L recently became a member of the Clinton Global Initiative, an association of eight leading utilities committed to the creation of a national institute for electric efficiency to develop regulatory models and convene supporting conferences in the power sector.

9.5 DISTRIBUTION SYSTEM LOSS EVALUATION

KCP&L assesses the feasibility and cost effectiveness of potential system upgrades or expansion projects on an on-going basis.

9.5.1 PROJECT EVALUATION

Potential projects are typically identified by system operating personnel, division engineering staff and distribution system planning engineers.

All projects require an appropriate engineering analysis and review for cost-benefit justification. An internal Economic Value Added (EVA) report is prepared to capture the benefits of the project.

9.5.2 LOSS-EVALUATED TRANSFORMER PURCHASING

KCP&L purchases distribution transformers on a total cost of ownership basis capitalized over a 30 year life. D.O.E. efficiency regulations have guided this methodology. KCP&L's current purchasing practices result in the lowest full-life total owning cost for distribution, medium and large power transformers.

9.5.3 SYSTEM POWER FACTOR

KCP&L frequently adds new capacitor bank projects to maintain overall power factor near unity, thereby releasing as much system capacity as practical. Automatic and remote-controlled capacitor banks help to keep the system voltage stable as loads are cycled on and off, while greater system capacity supports the addition of new load on the existing system. By maintaining a power factor near unity, lower current flows through the system resulting in less power lost (I^2R losses) to heating of cables, bus bars, transformers, etc. These devices will run cooler and last longer too.

9.5.4 TYPICAL PROJECTS WHICH AFFECT SYSTEM LOSS REDUCTIONS

KCP&L frequently introduces projects to increase supply voltage, thereby reducing load current and I^2R losses. Examples include conversions from 4kV to 12kV, and migration toward 161kV-fed distribution substations.

When engineering staff reviews new customer requests, customer load additions, maintenance needs, or other issues, they typically review the design of the secondary distribution system. Circuit lengths and the number of step-down transformers installed have a significant effect on overall system efficiency.

Reconductoring existing circuits or building new circuits to serve increased system loading have a direct effect on lowering system losses.

Upgrading existing substations or strategically placing new substations to serve areas with increasing load density also act to reduce system losses.

9.6 IMPORTANCE OF SYSTEM RELIABILITY

KCP&L emphasizes system reliability in all of its planning and operating policies and procedures. As a result, KCP&L received the 2007 Reliability One ™ National Reliability Excellence Award from the PA Consulting Group for excelling in delivering reliable electric service to its customers. The selection criteria include:

a. superior regional performance

b. sustained performance over time

c. improved performance over time

d. leadership in outage data collection and reporting systems, processes, procedures and controls

e. organizational and cultural focus on reliability

f. communication, planning, preparation, and response to major events

g. contributions to regional system security and reliability

In addition, KCP&L received the EEI Emergency Assistance Award for outstanding efforts to assist fellow utilities in power restoration during 2007. This is the result of KCP&L's extensive storm restoration organization and experience.

SECTION 10: PURCHASED POWER ALTERNATIVES

Rules 22.040 (1) and 22.040 (5) require utilities to evaluate "purchased power from utility sources" as an alternative supply side resource. To obtain values for market priced alternatives, KCP&L issued a Request For Proposal ("RFP") on August 17, 2007 for purchase power agreements (PPAs). A copy of the RFP is attached as Appendix 4.E.

The timing of RFP proposals does not align with KCPL's projected need for new generating resources. Therefore the pricing demonstrated through the RFP process is not anticipated to be available to meet future resource needs. The value of the RFP is to provide a view of current market pricing, which can be used to compare market pricing to the cost of ownership for similar technologies. Current market pricing is also utilized to develop a market-based "proxy" value for short-term PPAs.

The value of short-term PPAs is used in Integrated Analysis to smooth capacity balances. For example, during periods when capacity is above reserve requirements, capacity may be sold to generate revenue. Conversely, during periods when capacity is below reserve requirements, short-term capacity may be available for purchase to economically delay the need for resource additions.

Responses to the RFP fell into six general areas:

1. Landfill gas powered generation
2. Natural gas and diesel powered reciprocating engines
3. Purchased power from combined cycle units
4. Purchased power agreements from parties that offered aggregated distributed generation within the KCP&L service territory
5. An offer to sell back to KCP&L capacity from its Montrose station.
6. Wind powered generation

Evaluation of offers for wind generation are discussed separately because a wind-specific RFP was also issued on April 16, 2007 for 100 MW wind projects slated to come on-line in 2008 or later. The results of wind proposals from both RFP's are combined to expand the available data related to proposed wind generation projects.

The numerous proposals received in response to both RFP's include large files not conveniently combined for electronic transmission. Therefore, responses will be made available for review at KCP&L's headquarters and are not submitted as part of this filing.

10.1 RFP FINDINGS

Because the proposals received do not correspond to the projected timeline when new energy resources are required, the proposals were not passed on to Integrated Analysis. Instead, the values obtained from the RFP were utilized as a price point for comparison to KCP&L ownership of new generating resources. This comparison was used to develop a "proxy" value for Power Purchase Agreements (PPA's). The proxy value was then utilized in Integrated Analysis to value potential capacity contracts over the 20-year planning horizon. Capacity contracts include potential sales of excess capacity (when KCP&L has capacity in excess of reliability requirements) and potential purchases (when KCP&L is short of capacity to meet reliability requirements and to potentially delay the need for new supply-side resource additions).

10.1.1 RFP PROPOSALS (OTHER THAN WIND GENERATION)

Table 25 below compares RFP proposals other than wind offers, to the comparable cost of ownership.

Table 25: RFP Proposals - Other Than Wind Offers ** Highly Confidential **

[redacted]

Pre-Screening Busbar (Ownership) Comparisons

[redacted]

10.1.2 RFP PROPOSALS FOR WIND

Wind generation offers from the August 17, 2007 general-RFP and the April 16, 2007 wind-specific-RFP are summarized below. Offers for both Build-Transfer Agreements (BTA) and Power Purchase Agreements (PPA) are included in the summaries. Table 26 summarizes the BTA offers. Table 27 summarizes the PPA offers.

Table 26: RFP Wind Build-Transfer Offers ** Highly Confidential **

RFP WIND BUILD-TRANSFER OFFERS
[redacted]

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Table 27: RFP Wind PPA Offers ** Highly Confidential **

RFP Propsals for Wind PPA's
[redacted]

The cost to KCP&L in Table 27 is shown as the "Energy Value (Includes $20/MWh PTC). In each proposal, the developer retains the value of the PTC and the Renewable Energy Credits (REC) associated with the wind generation.

The pricing of wind proposals as shown above ranks these offers ahead of offers based on other technologies. However, the intermittent nature of wind generation is not captured in the above comparisons and therefore a direct comparison of busbar costs to other technology options is not a complete or valid comparison. Wind, as well as other technologies passing the pre-screen evaluations, are more fully evaluated under Integrated Analysis and Risk Analysis and Strategy Selection.

10.2 PROXY VALUE OF PPA'S FOR INTEGRATED ANALYSIS

As shown in Table 27 above, most RFP proposals exceed the cost of ownership and would therefore be excluded from Integrated Analysis. However, short-term purchases and sales are likely over the 20-year planning horizon. Sales may be available to serve as a revenue source during periods of excess capacity. Purchases may be available to provide fill-in capacity and energy to delay the installation of new resources. Therefore, the projected value of PPA's is included in Integrated Analysis.

The market value of PPAs is a dynamic value determined by many variables including the availability of excess capacity in the region and available firm transmission paths. As shown in the table above, the market price for longer-term capacity and energy is routinely higher than the cost of ownership. However, when excess capacity is reasonably available within the region, short term PPAs may be priced below the cost of ownership. Such offers are generally supported by market priced energy. As with wind above, a direct comparison to ownership cost is an incomplete evaluation. The combined value of (potentially) lower priced capacity from PPAs plus the supporting energy at market prices would need to be evaluated in more detailed portfolio modeling to fully evaluate the economics of this alternative.

By offering low priced capacity backed by market priced energy, providers with excess capacity can generate low risk revenue streams. Over the 20-year planning horizon, such short term PPAs cannot be guaranteed, since future regional capacity balances are uncertain. Ultimately, the market will likely recover the full cost of capacity based on the installed cost of the asset. Therefore, the proxy value for PPAs over the long term is expected to mirror the cost of ownership. Based on the pre-screening evaluation, the annual carrying cost of installing a combustion turbine (CT) is approximately **[redacted]** million including transmission cost. This provides accredited capacity of 79 MW. This equates to a levelized annual capacity payment of **[redacted]** (current year $'s) over the expected life of the CT. Offering this price for capacity with the supporting energy supplied at market prices would allow recovery of the asset's fixed cost without exposure to market price risk. Therefore **[redacted]** is the value KCPL projects for the long-term value of market capacity supported by market priced energy.

10.3 SUMMARY OF RFP RESULTS

Proposals received are not available when KCP&L needs to add supply-side resources. The offers will not be valid resource alternatives for Integrated Analysis, and the values of these offers are therefore not carried over to Integrated Analysis.

Instead, the proxy cost for market based short-term capacity contacts are utilized in Integrated Analysis.

SECTION 11: REPORTING REQUIREMENTS

A summary of the items required under 22.040 Supply-Side Resource Analysis, (9) is included below.

Tables 3 through 6 above and Appendix 4.A address the requirements of 22.040 (9) (A) and 22.040 (9) (A) 1.

Table 9 lists the technologies passed to Integrated Analysis and provides the required data to satisfy Rule 22.040 (9) (A) 2.

Rule 22.040 (9) (A) 3 requires an explanation of the reasons technologies were excluded from Integrated Analysis. This requirement is discussed above under Section 3.2.3 and Section 3.2.4.

Rule 22.040 (9) (B) requires a list of candidate resources for which uncertainty forecasts, cost estimates and probability distributions have been developed. The required uncertainties have been identified for all candidate resources passed to Integrated Analysis including:

- Fuel and environmental uncertainties (forecasts) are shown in Section 6: and Section 7: respectively. Additional details are also included in Appendix 4.C.
- The estimated ranges for capital cost and operating and maintenance costs are shown in Table 28 below.

Table 28: Range of Technology Capital and Operating Costs **__** Highly Confidential **__**

[redacted]

Rule 22.040 (9) (C) requires a summary of the results of the uncertainty analysis described under Rule 22.040 (8) for candidate resource options. The Ventyx report attached as Appendix 4.G provided the sensitivity analysis for the required major uncertainties.

Rule 22.040 (9) (D) requires a summary of mitigation costs associated with Probable Environmental Costs. The response to this requirement is included above in Section 5: of this report. This rule also requires a description of how the costs and probabilities were determined. The mitigation costs were developed by KCP&L's Environmental and Supply Engineering Departments. The subjective probabilities were developed through internal discussions with key decision makers from the Fuels Department, Supply Engineering, Energy Resource Management and the Environmental Departments.

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