VOLUME 7:

RESOURCE ACQUISITION STRATEGY SELECTION

KANSAS CITY POWER & LIGHT COMPANY (KCP&L)

INTEGRATED RESOURCE PLAN

4 CSR 240-22.070

CASE NO. EO-2012-0323

APRIL, 2012

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PURPOSE: This rule requires the utility to select a preferred resource plan, develop an implementation plan, and officially adopt a resource acquisition strategy. The rule also requires the utility to prepare contingency plans and evaluate the demand-side resources that are included in the resource acquisition strategy.

SECTION 1: PREFERRED RESOURCE PLAN

The utility shall select a preferred resource plan from among the alternative resource plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060. The utility shall describe and document the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by utility decision makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. The utility shall provide the names, titles, and roles of the utility decision–makers in the preferred resource plan selection process. The preferred resource plan shall satisfy at least the following conditions:

(A) In the judgment of utility decision makers, strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2);
See response in Rule 070(1)(D)

(B) Invest in advanced transmission and distribution technologies unless, in the judgment of the utility decision-makers, investing in those technologies to upgrade transmission and/or distribution networks is not in the public interest;
See response in Rule 070(1)(D)

(C) Utilize demand-side resources to the maximum amount that comply with legal mandates and, in the judgment of the utility decision-makers, are consistent with the public interest and achieve state energy policies; and
See response in Rule 070(1)(D)

(D) In the judgment of the utility decision makers, the preferred plan, in conjunction with the deployment of emergency demand response measures and access to short-term and emergency power supplies, has sufficient resources to serve load forecasted under extreme weather conditions pursuant to 4CSR 240-22.030(8)(B) for the implementation period. If the utility cannot affirm the sufficiency of resources, it shall consider an alternative resource plan or modifications to its preferred resource plan that can meet extreme weather conditions. 22.070 (1) (D)
The Preferred Plan that has been selected for KCP&L is shown in Table 1 below:

Table 1: KCP&L Preferred Plan

Year	CC's (MW)	Solar (MW)	Wind (MW)	DSM A (MW)	Retire (MW)	Existing Capacity (MW)
2012	-			89		4,492
2013	-			89		4,553
2014	-			169		4,609
2015	-			185		4,602
2016	-		100	195	170	4,397
2017	-			213		4,397
2018	-	11		201		4,397
2019	-			223		4,397
2020	-		200	242		4,397
2021	-	6		215		4,397
2022	-			279		4,397
2023	-	3	100	295		4,397
2024	-			312		4,341
2025	-			328		4,341
2026	-			346		4,341
2027	-			363		4,341
2028	150			380		4,341
2029	-			397		4,341
2030	-			415		4,341
2031	-			433		4,341

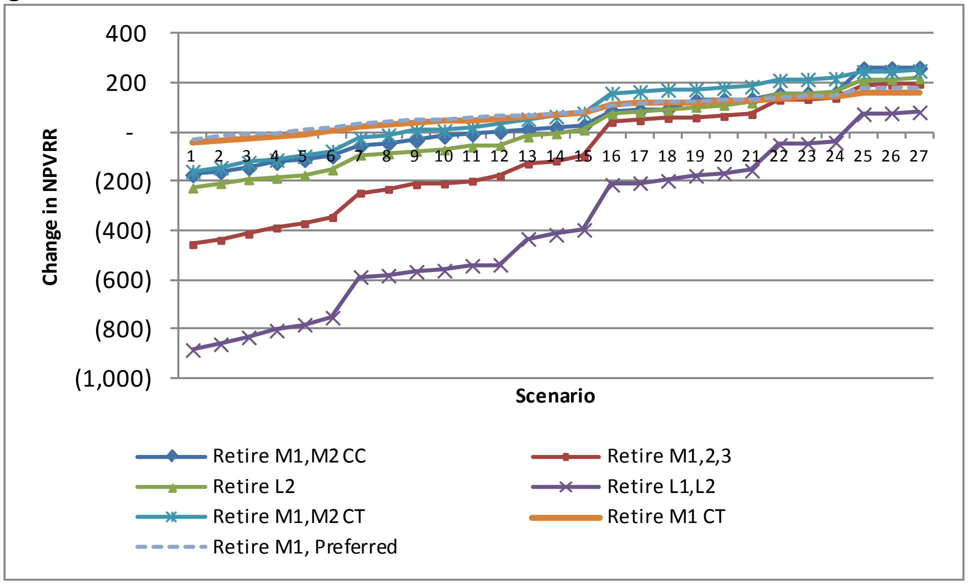
Based upon current Missouri and Kansas RPS rule requirements, the Preferred Plan includes 20 MW of solar additions and 400 MW of wind additions over the twenty-year planning period. It should be noted that solar and wind additions could be obtained from power purchase agreements (PPA), renewable energy credits (RECs) purchases, or utility ownership. “DSM A” consists of a suite of twelve Energy Efficiency and two Demand Response programs that KCP&L considers the capacity and energy estimated from these programs comprise realistically achievable levels. The retirement of 170 MW in 2016 represents Montrose Unit 1. The environmental drivers that contribute to the Montrose Unit 1 retirement included Mercury and Air Toxics Standards Rule, Ozone National Ambient Air Quality Standards (NAAQS), PM NAAQS, Clean Water Act Section 316(a) and (b), Effluent Guidelines, and Coal Combustion Residuals Rule. These rules are currently not in effect and will be monitored by KCP&L prior to the projected retirement year 2016 to determine if the current decision to retire Montrose Unit 1 continues to be prudent.

The Preferred Plan was not the lowest cost plan from a Net Present Value of Revenue Requirement (NPVRR) perspective. Alternative Resource Plan DBEK1 had the lowest expected NPVRR of all modeled plans. This plan included the “D” level of DSM which was developed to satisfy the requirement of Special Contemporary Issue h. stated in Order EO-2012-0041, “Analyze and document aggressive DSM portfolios without constraints”. This “Aggressive” D-level of DSM is not considered to be realistically achievable. The plan producing the next lowest expected value of NPVRR was chosen as the Preferred Plan.

It should be noted that this plan is based upon resource planning in tandem with KCP&L-Greater Missouri Operations Company (GMO) and provides benefit to Missouri retail customers by planning on a combined company basis. The results of resource analysis assuming a combined-company basis is that KCP&L benefitted by $8 Million on a 20-year NPVRR basis in savings in comparison to the plan that would be selected for KCP&L on a stand-alone basis. This savings is due to increased capacity sales and the opportunity to share with GMO a smaller portion of a new combined cycle facility that would be built in 2021 under a combined-company scenario.

In addition to selecting the Preferred Plan based on a low NPVRR, KCP&L looked at the alternative plan risks across 27 different Scenarios. Figure 1 shown below compares the difference in NPVRR for selected alternative resource plans and the resource plan where no KCP&L coal plants are retired. The NPVRR difference is shown for each of the 27 scenarios analyzed. From this chart it is possible to see the number of Scenarios where the selected alternative resource plan performs better or worse than the resource plan where no coal plants are retired. For example, the alternative resource plan where LaCygne 1 and LaCygne 2 are retired ("Retire L1, L2") performs better than the no retirement plan in only 3 of the 27 Scenarios analyzed while the Preferred Plan ("Retire M1, Preferred") performs better than the no retirement plan in 23 of the 27 Scenarios analyzed. In the 3 Scenarios that the Preferred Plan performs worse than the no retirement plan, the differences in NPVRR is small which indicates little downside risk in retiring Montrose 1. The chart also shows that as additional coal capacity is retired, the downside risk (i.e., change in NPVRR) increases with each additional plant retirement, with only a marginal increase in upside potential. Therefore, not only does the Preferred Plan have a low NPVRR, it also minimizes the downside risk associated with additional coal capacity retirements while preserving the upside potential relative to the no retirement plan.

Figure 1: Selected Resource Plan Risk Relative to All Retrofit Plan



The Preferred Plan also meets the fundamental planning objectives as required by Rule 22.010(2) to provide the public with energy services that are safe, reliable, and efficient, at just and reasonable rates, in compliance with all legal mandates, and in a manner that serves the public interest and is consistent with state energy and environmental policies. The Preferred Plan was reviewed and approved by Terry D. Bassham, President and Chief Operating Officer and Scott H. Heidtbrink, Senior Vice President – Supply.

The Forecast of Capacity Balance worksheet associated with the KCP&L Preferred Plan is shown in Table 2 below. It should be noted that the "Peak Forecast" data is based upon an extreme weather forecast. The Capacity Balance shows that reserve obligations are met each year.

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Table 2: KCP&L Forecast of Capacity Balance - Preferred Plan **Highly Confidential**

Name of Utility	Kansas City Power & Light																			
Year of Electric Utility Resource Planning Filing	1-Apr-12																			
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
A. System Generating Capacity (KCPL share)																				
Base Capacity																				
Wolf Creek	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547	547
Iatan I	493	493	493	493	493	493	493	493	493	493	493	493	493	493	493	493	493	493	493	493
Iatan II	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482	482
Hawthorn 5	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564	564
La Cygne 1	368	368	368	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372	372
La Cygne 2	343	343	343	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332	332
Montrose 1	170	170	170	170																
Montrose 2	164	164	164	164	164	164	164	164	164	164	164	164	164	164	164	164	164	164	164	164
Montrose 3	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176	176
Total Base Capacity	3,307	3,307	3,307	3,300	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130	3,130
Intermediate Capacity																				
Hawthorn 6 & 9	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232
Combined Cycle Additions																	150	150	150	150
Total Intermediate Capacity	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	232	382	382	382	382
Peaking Capacity																				
Hawthorn 7	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Hawthorn 8	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
Northeast 11	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Northeast 12	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Northeast 13	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51	51
Northeast 14	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
Northeast 15	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Northeast 16	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44	44
Northeast 17	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54	54
Northeast 18	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56	56
Northeast Black Start Generator	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
West Gardner Comb Turb 1	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
West Gardner Comb Turb 2	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
West Gardner Comb Turb 3	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77	77
West Gardner Comb Turb 4	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78	78
Osawatomie Comb Turb 1	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
Total Peaking Capacity	948	948	948	948	948	948	948	948	948	948	948	948	948	948	948	948	948	948	948	948
Intermittent Capacity (Nameplate)																				
Spearville I	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101	101
Spearville II	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48	48
Total Intermittent Capacity	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
Percent Accredited Intermittent Capacity	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%	8.15%
Total Accredited Intermittent Capacity	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1	12.1
Wind Additions					8	8	8	8	24	24	24	32	32	32	32	32	32	32	32	32
Solar Additions							11	11	11	17	17	20	20	20	20	20	20	20	20	20
Total Intermittent Capacity with Additions	12.1	12.1	12.1	12.1	20.1	20.1	31.1	31.1	47.1	53.1	53.1	64.1	64.1	64.1	64.1	64.1	64.1	64.1	64.1	64.1
Total Generation Capacity	4,499	4,499	4,499	4,492	4,330	4,330	4,341	4,341	4,357	4,363	4,363	4,374	4,374	4,374	4,374	4,374	4,524	4,524	4,524	4,524
B. Capacity Transactions																				

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KCP&L deploys advanced distribution technologies selectively to the network where they are the most economical alternative to maintain the desired level of operational performance, reliability, and power quality. In Volume 4.5, Section 1.4, there is a discussion regarding how KCP&LGMO plans distribution network upgrades, many of which incorporate the deployment of the previously established advanced grid technologies described in Section 4.6.2.2.

Regarding transmission, the advanced transmission technologies that KCP&L has invested in are focused on improving reliability and deliverability of electric service. These technologies would be applied equally across any supply side resource alternatives and would not impact the decision to select a particular resource option.

The Preferred Plan was tested under extreme weather conditions as defined by Rule 240-22.030(8)(B). The amount of unserved energy under this extreme condition is small and does not preclude the adoption of the plan. The performance measure effects and annual amount of unserved energy given extreme weather conditions are provided below.

Table 3: Performance Measure Impact - Extreme Weather

Year	Revenue Requirement ($MM)	Revenue Requirement ($MM) Extreme Weather	Levelized Annual Rates ($/kw-hr)	Levelized Annual Rates ($/kw-hr) Extreme Weather	Rate Increase	Rate Increase Extreme Weather	Times Interest Earned	Times Interest Earned Extreme Weather	Total Debt to Capital	Total Debt to Capital Extreme Weather	Cap Ex to FFO	Cap Ex to FFO Extreme Weather
2012	1,707	1,722	0.107	0.105	0.00%	0.00%	4.466	4.466	0.504	0.504	1.168	1.168
2013	1,679	1,695	0.104	0.102	-2.56%	-2.46%	4.469	4.469	0.504	0.504	0.860	0.860
2014	1,754	1,771	0.108	0.106	3.42%	3.45%	4.393	4.393	0.504	0.504	0.692	0.692
2015	1,736	1,754	0.106	0.104	-1.59%	-1.47%	4.197	4.197	0.504	0.504	0.608	0.608
2016	1,866	1,886	0.113	0.111	6.62%	6.61%	4.533	4.533	0.504	0.504	1.283	1.283
2017	1,921	1,943	0.116	0.114	2.55%	2.69%	4.427	4.427	0.504	0.504	1.722	1.722
2018	1,990	2,017	0.119	0.118	2.94%	3.16%	4.531	4.531	0.504	0.504	1.093	1.093
2019	2,016	2,043	0.120	0.119	0.58%	0.55%	4.396	4.396	0.504	0.504	0.796	0.796
2020	2,156	2,184	0.127	0.126	5.91%	5.91%	4.477	4.477	0.504	0.504	1.877	1.877
2021	2,179	2,210	0.128	0.127	0.58%	0.73%	4.221	4.221	0.504	0.504	1.437	1.437
2022	2,205	2,236	0.129	0.127	0.45%	0.44%	4.373	4.373	0.504	0.504	1.136	1.136
2023	2,263	2,298	0.131	0.130	1.84%	2.03%	4.354	4.354	0.504	0.504	1.881	1.881
2024	2,282	2,320	0.131	0.130	-0.23%	-0.13%	4.350	4.350	0.504	0.504	2.198	2.198
2025	2,259	2,296	0.129	0.127	-1.63%	-1.62%	4.348	4.348	0.504	0.504	1.832	1.832
2026	2,296	2,335	0.129	0.128	0.74%	0.75%	4.316	4.316	0.504	0.504	1.472	1.472
2027	2,328	2,372	0.130	0.129	0.35%	0.59%	4.250	4.250	0.504	0.504	1.618	1.618
2028	2,286	2,328	0.126	0.125	-3.08%	-3.10%	4.203	4.203	0.504	0.504	1.572	1.572
2029	2,307	2,352	0.126	0.125	0.11%	0.23%	3.967	3.967	0.505	0.505	1.584	1.584
2030	2,354	2,400	0.127	0.127	0.89%	0.94%	3.951	3.951	0.505	0.505	1.594	1.594
2031	2,367	2,414	0.127	0.126	-0.52%	-0.45%	3.932	3.932	0.505	0.505	1.535	1.535

Table 4: Extreme Weather Unserved Energy

Year	Unservered MWh
2012	-
2013	-
2014	-
2015	102
2016	-
2017	-
2018	1,841
2019	3,215
2020	-
2021	-
2022	-
2023	-
2024	29
2025	613
2026	-
2027	-
2028	316
2029	-
2030	-
2031	11

SECTION 2: RANGES OF CRITICAL UNCERTAIN FACTORS

The utility shall specify the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the preferred resource plan is judged to be appropriate and explain how these limits were determined. The utility shall also describe and document its assessment of whether, and under what circumstances, other uncertain factors associated with the preferred resource plan could materially affect the performance of the preferred resource plan relative to alternative resource plans. 22.070 (2)

The ranges of critical uncertain factors are calculated by finding the value at which the critical uncertain factor needs to change in order for the Preferred Resource Plan to no longer be the lowest cost option. The values of the NPVRR for the Preferred Resource Plan and the lowest cost plan under extreme conditions are compared and by using linear interpolation a crossover point value is found and expressed as a percent of the range of the critical uncertain factor. These percentages are superimposed on the high, mid and low forecasts for each critical uncertain factor to develop the resulting ranges.

The Company has selected its Preferred Plan by assuming combined planning for both KCPL and GMO. This assumption has changed the risk impact when comparing stand-alone company alternatives. As such some critical uncertain factors do not remain critical to the decision of the joined company.

In the combined company analysis the preferred plan, AJDC2 and one other plan, AGDC2, proved to be the lowest cost plan under different risk scenarios. The values of these two plans NPVRR under each of these risks are detailed in the following table.

Table 5: Risk Scenario NPVRR

NPVRR($MM)	High Load	High NG	High CO2	EV	Low CO2	Low NG	Low Load
AGDC2	33,436.3	32,469.6	35,429.8	33,068.4	31,273.4	33,091.1	32,196.9
AJDC2	33,443.5	32,543.4	35,374.8	33,064.5	31,310.4	33,022.2	32,193.3

With combined company planning, the remaining uncertain factors which may cause the company to modify the preferred plan are limited to low CO_2, high load growth and high natural gas prices. Details of the calculations for range of uncertain factors are given in the following sections.

2.1 CRITICAL UNCERTAIN FACTOR: CO_2

The uncertain factor range calculation is detailed in Table 6 below. No high CO_2 range exists as increasing the CO_2 price forecast does not cause the contingency plan to out-perform the preferred plan, or any other plan.

Table 6: CO_2 Uncertain Factor Range

CO_2		
Plan	**Mid**	**High**
AJDC2	33,065	35,375
AJDC2	33,065	35,375
Percent	from Mid	from Low
Upper %	N/A	N/A
Plan	**Mid**	**Low**
AGDC2	33,068	31,273
AJDC2	33,065	31,310
Percent	from Mid	from Low
Lower %	-9.47%	45.26%

The resulting limits of the range of this critical uncertain factor are detailed in Figure 2 below:

Figure 2: CO_2 Uncertain Factor Range Limits ** Highly Confidential **

CO_2 Price Forecast
**** Highly Confidential ****

[redacted]

2.2 CRITICAL UNCERTAIN FACTOR: LOAD

The uncertain factor range calculation is detailed in Table 7 below. No low load growth range exists as decreasing the load growth forecast does not cause the contingency plan to out-perform the preferred plan, or any other plan.

Table 7: Load Uncertain Factor Range

Load		
Plan	Mid	High
AGDC2	33,068	33,436
AJDC2	33,065	33,443
Percent	from Mid	from Low
Upper %	35.12%	67.56%
Plan	Mid	Low
AJDC2	33,065	32,193
AJDC2	33,065	32,193
Percent	from Mid	from Low
Lower %	N/A	N/A

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The resulting limits of the range of this critical uncertain factor are detailed in the figures below.

Figure 3: Peak Demand Range Limit

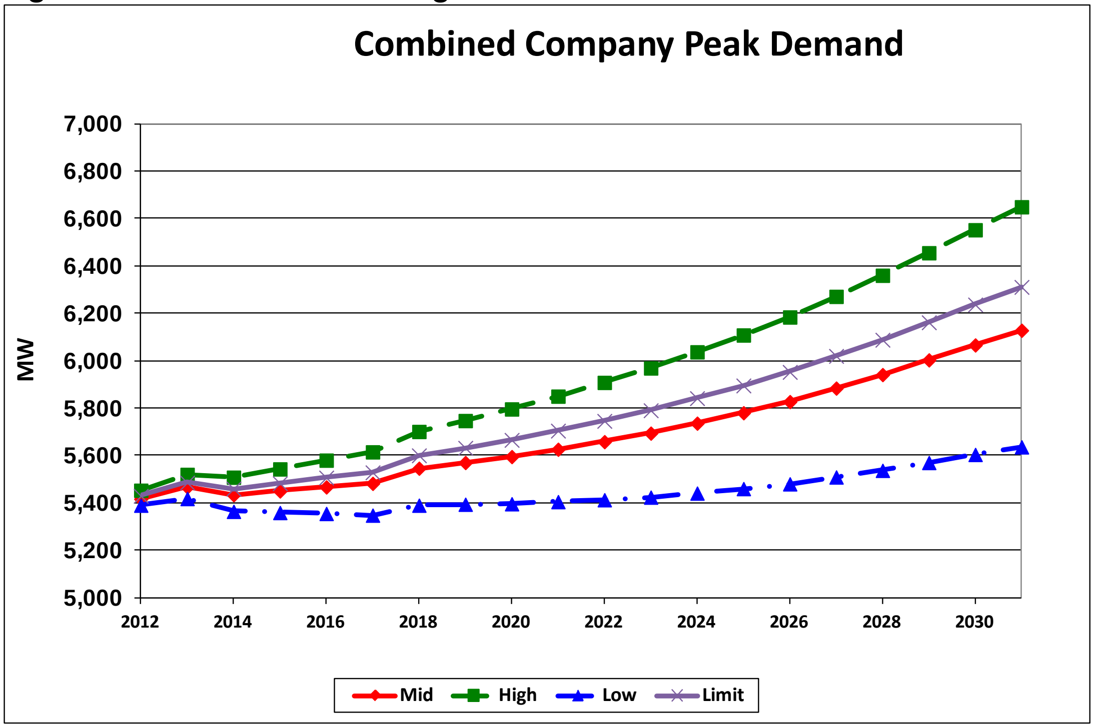
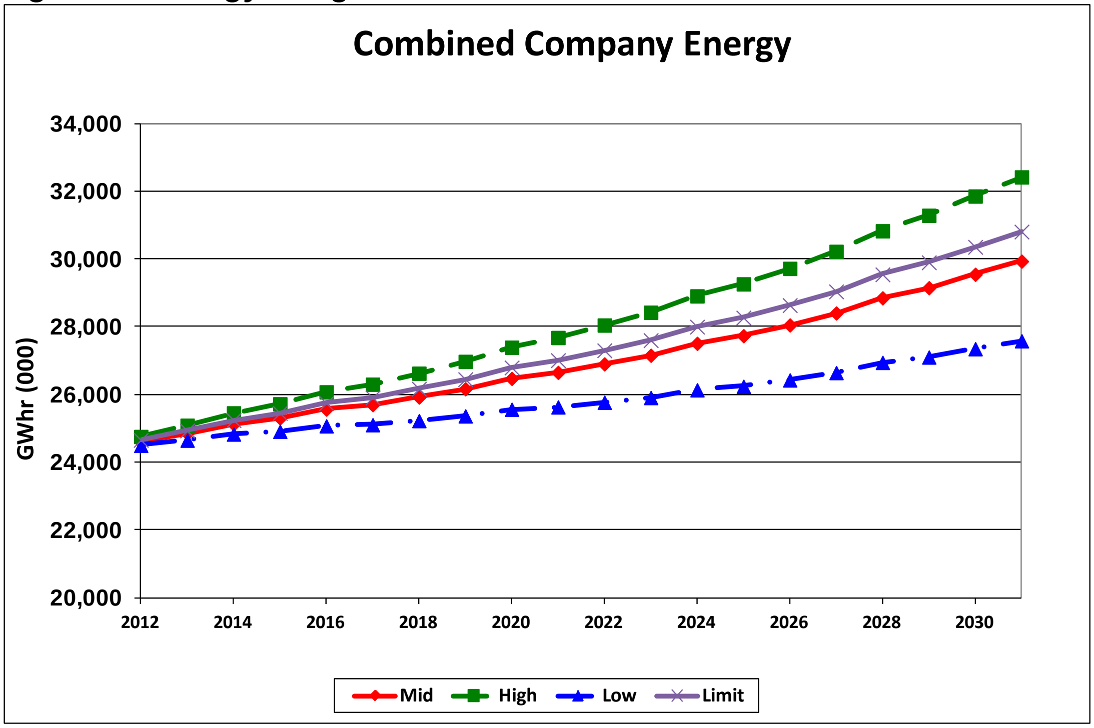


Figure 4: Energy Range Limit



2.3 CRITICAL UNCERTAIN FACTOR: NATURAL GAS

The uncertain factor range calculation is detailed in Table 8 below. No low Natural Gas range exists as decreasing the Natural Gas price forecast does not cause the contingency plan to out-perform the preferred plan, or any other plan.

Table 8: Natural Gas Uncertain Factor Range

Natural Gas		
Plan	**Mid**	**High**
AGDC2	33,068	32,470
AJDC2	33,065	32,543
Percent	from Mid	from Low
Upper %	4.97%	52.49%
Plan	**Mid**	**Low**
AJDC2	33,065	33,022
AJDC2	33,065	33,022
Percent	from Mid	from Low
Lower %	N/A	N/A

The resulting limits of the range of this critical uncertain factor are detailed in Figure 5 below:

Figure 5: Natural Gas Uncertain Factor Range Limit ** Highly Confidential **

Natural Gas Price Forecasts
**** Highly Confidential ****

[redacted]

2.4 CRITICAL UNCERTAIN FACTOR: CAPITAL AND CONSTRUCTION COSTS

In the preliminary sensitivity studies, it was determined that the plans would only be sensitive to an upward movement in financial drivers. The impact on the performance of the Preferred Plan was gauged using the high values of financing costs and construction costs. The revenue requirement impact of this sensitivity is detailed in the following table.

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Table 9: Capital and Construction Cost Uncertainty – Preferred Plan

Year	Revenue Requirement ($MM)	Revenue Requirement ($MM) High Finance & Construction Cost	Levelized Annual Rates ($/kw-hr)	Levelized Annual Rates ($/kw-hr) High Finance & Construction Cost	Rate Increase	Rate Increase: High Finance & Construction Cost	Times Interest Earned	Times Interest Earned High Finance & Construction Cost	Total Debt to Capital	Total Debt to Capital High Finance & Construction Cost	Cap Ex to FFO	Cap Ex to FFO High Finance & Construction Cost
2012	1,707	1,805	0.107	0.113	0.00%	0.00%	4.466	5.092	0.504	0.504	1.168	1.345
2013	1,679	1,781	0.104	0.111	-2.56%	-2.27%	4.469	5.183	0.504	0.504	0.860	0.982
2014	1,754	1,855	0.108	0.114	3.42%	3.13%	4.393	5.000	0.504	0.504	0.692	0.770
2015	1,736	1,836	0.106	0.112	-1.59%	-1.56%	4.197	4.661	0.504	0.504	0.608	0.652
2016	1,866	1,997	0.113	0.121	6.62%	7.84%	4.533	5.010	0.504	0.504	1.283	1.441
2017	1,921	2,049	0.116	0.124	2.55%	2.23%	4.427	4.774	0.504	0.504	1.722	1.914
2018	1,990	2,114	0.119	0.127	2.94%	2.50%	4.531	4.673	0.504	0.504	1.093	1.122
2019	2,016	2,133	0.120	0.127	0.58%	0.17%	4.396	4.304	0.504	0.503	0.796	0.766
2020	2,156	2,294	0.127	0.135	5.91%	6.52%	4.477	4.286	0.504	0.504	1.877	1.972
2021	2,179	2,309	0.128	0.136	0.58%	0.17%	4.221	3.973	0.504	0.504	1.437	1.442
2022	2,205	2,330	0.129	0.136	0.45%	0.20%	4.373	4.000	0.504	0.504	1.136	1.097
2023	2,263	2,395	0.131	0.139	1.84%	2.00%	4.354	3.971	0.504	0.504	1.881	1.912
2024	2,282	2,406	0.131	0.138	-0.23%	-0.63%	4.350	3.940	0.504	0.504	2.198	2.252
2025	2,259	2,377	0.129	0.135	-1.63%	-1.82%	4.348	3.951	0.504	0.504	1.832	1.832
2026	2,296	2,411	0.129	0.136	0.74%	0.48%	4.316	3.938	0.504	0.504	1.472	1.441
2027	2,328	2,438	0.130	0.136	0.35%	0.09%	4.250	3.888	0.504	0.504	1.618	1.592
2028	2,286	2,406	0.126	0.133	-3.08%	-2.57%	4.203	3.908	0.504	0.504	1.572	1.585
2029	2,307	2,423	0.126	0.132	0.11%	-0.11%	3.967	3.688	0.505	0.504	1.584	1.625
2030	2,354	2,467	0.127	0.133	0.89%	0.67%	3.951	3.680	0.505	0.505	1.594	1.635
2031	2,367	2,477	0.127	0.132	-0.52%	-0.66%	3.932	3.673	0.505	0.505	1.535	1.574

2.5 CRITICAL UNCERTAIN FACTOR: FEDERAL ENERGY EFFICIENCY STANDARD

In the preliminary sensitivity studies, it was determined that the company would be sensitive to a Federal Energy Efficiency Standard, modeled on HR889. The impact on the performance of the Preferred Plan was gauged using the assumption that the Preferred Plan was subject to this standard. All compliance above the DSM in the preferred plan would be achieved through alternative compliance payments to the Federal and State governments. The revenue requirement impact of this sensitivity is detailed in the following table.

Table 10: Federal EE Standard Uncertainty – Preferred Plan

Year	Revenue Requirement ($MM)	Revenue Requirement ($MM) Federal Energy Efficiency Standard	Levelized Annual Rates ($/kw-hr)	Levelized Annual Rates ($/kw-hr) Federal Energy Efficiency Standard	Rate Increase	Rate Increase Federal Energy Efficiency Standard	Times Interest Earned	Times Interest Earned Federal Energy Efficiency Standard	Total Debt to Capital	Total Debt to Capital Federal Energy Efficiency Standard	Cap Ex to FFO	Cap Ex to FFO Federal Energy Efficiency Standard
2012	1,707	1,709	0.107	0.107	0.00%	0.00%	4.466	4.470	0.504	0.504	1.168	1.191
2013	1,679	1,688	0.104	0.105	-2.56%	-2.20%	4.469	4.474	0.504	0.504	0.860	0.897
2014	1,754	1,773	0.108	0.109	3.42%	3.99%	4.393	4.399	0.504	0.504	0.692	0.744
2015	1,736	1,768	0.106	0.108	-1.59%	-0.80%	4.197	4.204	0.504	0.504	0.608	0.680
2016	1,866	1,917	0.113	0.116	6.62%	7.52%	4.533	4.532	0.504	0.504	1.283	1.450
2017	1,921	1,995	0.116	0.121	2.55%	3.69%	4.427	4.425	0.504	0.504	1.722	2.004
2018	1,990	2,095	0.119	0.126	2.94%	4.30%	4.531	4.524	0.504	0.504	1.093	1.339
2019	2,016	2,158	0.120	0.129	0.58%	2.28%	4.396	4.391	0.504	0.503	0.796	1.038
2020	2,156	2,343	0.127	0.138	5.91%	7.51%	4.477	4.462	0.504	0.503	1.877	2.519
2021	2,179	2,409	0.128	0.142	0.58%	2.35%	4.221	4.206	0.504	0.503	1.437	1.985
2022	2,205	2,474	0.129	0.144	0.45%	1.92%	4.373	4.331	0.504	0.503	1.136	1.612
2023	2,263	2,564	0.131	0.148	1.84%	2.88%	4.354	4.304	0.504	0.503	1.881	2.698
2024	2,282	2,609	0.131	0.149	-0.23%	0.67%	4.350	4.289	0.504	0.504	2.198	3.197
2025	2,259	2,604	0.129	0.148	-1.63%	-0.83%	4.348	4.280	0.504	0.504	1.832	2.727
2026	2,296	2,651	0.129	0.149	0.74%	0.87%	4.316	4.248	0.504	0.504	1.472	2.244
2027	2,328	2,687	0.130	0.150	0.35%	0.36%	4.250	4.187	0.504	0.504	1.618	2.495
2028	2,286	2,651	0.126	0.146	-3.08%	-2.64%	4.203	4.144	0.504	0.504	1.572	2.480
2029	2,307	2,678	0.126	0.146	0.11%	0.19%	3.967	3.936	0.505	0.504	1.584	2.582
2030	2,354	2,730	0.127	0.148	0.89%	0.83%	3.951	3.921	0.505	0.504	1.594	2.608
2031	2,367	2,749	0.127	0.147	-0.52%	-0.38%	3.932	3.904	0.505	0.504	1.535	2.515

2.6 CONTEMPORARY ISSUE – LOSS OF LOAD

The contemporary issue process identified a concern in the effect on Preferred Plan performance measures on the sustained loss of major load. This effect is detailed below.

Table 11: Contemporary Issue - Loss of Load

Year	Revenue Requirement ($MM)	Revenue Requirement ($MM) Load Loss	Levelized Annual Rates ($/kw-hr)	Levelized Annual Rates ($/kw-hr) Load Loss	Rate Increase	Rate Increase Load Loss	Times Interest Earned	Times Interest Earned Load Loss	Total Debt to Capital	Total Debt to Capital Load Loss	Cap Ex to FFO	Cap Ex to FFO Load Loss
2012	1,707	1,697	0.107	0.108	0.00%	0.00%	4.466	4.466	0.504	0.504	1.168	1.168
2013	1,679	1,669	0.104	0.106	-2.56%	-2.62%	4.469	4.469	0.504	0.504	0.860	0.860
2014	1,754	1,744	0.108	0.109	3.42%	3.39%	4.393	4.393	0.504	0.504	0.692	0.692
2015	1,736	1,725	0.106	0.107	-1.59%	-1.64%	4.197	4.197	0.504	0.504	0.608	0.608
2016	1,866	1,854	0.113	0.115	6.62%	6.60%	4.533	4.533	0.504	0.504	1.283	1.283
2017	1,921	1,908	0.116	0.117	2.55%	2.52%	4.427	4.427	0.504	0.504	1.722	1.722
2018	1,990	1,975	0.119	0.121	2.94%	2.83%	4.531	4.531	0.504	0.504	1.093	1.093
2019	2,016	2,001	0.120	0.121	0.58%	0.55%	4.396	4.396	0.504	0.504	0.796	0.796
2020	2,156	2,140	0.127	0.129	5.91%	5.88%	4.477	4.477	0.504	0.504	1.877	1.877
2021	2,179	2,161	0.128	0.129	0.58%	0.52%	4.221	4.221	0.504	0.504	1.437	1.437
2022	2,205	2,186	0.129	0.130	0.45%	0.38%	4.373	4.373	0.504	0.504	1.136	1.136
2023	2,263	2,242	0.131	0.132	1.84%	1.79%	4.354	4.354	0.504	0.504	1.881	1.881
2024	2,282	2,260	0.131	0.132	-0.23%	-0.32%	4.350	4.350	0.504	0.504	2.198	2.198
2025	2,259	2,235	0.129	0.129	-1.63%	-1.70%	4.348	4.348	0.504	0.504	1.832	1.832
2026	2,296	2,271	0.129	0.130	0.74%	0.66%	4.316	4.316	0.504	0.504	1.472	1.472
2027	2,328	2,302	0.130	0.131	0.35%	0.29%	4.250	4.250	0.504	0.504	1.618	1.618
2028	2,286	2,259	0.126	0.126	-3.08%	-3.16%	4.203	4.203	0.504	0.504	1.572	1.572
2029	2,307	2,278	0.126	0.126	0.11%	0.00%	3.967	3.967	0.505	0.505	1.584	1.584
2030	2,354	2,323	0.127	0.128	0.89%	0.84%	3.951	3.951	0.505	0.505	1.594	1.594
2031	2,367	2,333	0.127	0.127	-0.52%	-0.64%	3.932	3.932	0.505	0.505	1.535	1.535

SECTION 3: BETTER INFORMATION

The utility shall describe and document its quantification of the expected value of better information concerning at least the critical uncertain factors that affect the performance of the preferred resource plan, as measured by the present value of utility revenue requirements. The utility shall provide a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities. 22.070 (3)

The Company calculated the value of better information for each of the critical uncertain factors identified in the preliminary sensitivity test. For each uncertainty, the preferred plan NPVRR for the specific uncertainty scenarios (or endpoints) was compared to the better plan under each extreme uncertainty condition. The comparison was made on an expected value basis assuming that only those three particular scenarios (high value uncertainty, mid value and low value uncertainty) would occur. Baye's Theorem was applied to the endpoint probabilities to develop conditional probabilities for the calculation scenarios. The difference between the expected value of the preferred plan and the expected value of the better information results is the expected value of better information.

These values represent the maximum amount the company should be willing to spend to study each of these uncertainties. It must be noted that should a Preferred Plan out-perform all alternatives across the range of a critical risk, the calculation for better information will yield a value of zero.

The results for these calculations are shown in below.

Table 12: Better Information - CO_2

CO2					
Preferred Plan	**Plan**	**NPVRR**	**EP Prob**	**Probability**	**Expected Value**
High CO2	AJDC2	35,375	6.25%	25.00%	33,204
Mid	AJDC2	33,065	12.50%	50.00%	
Low CO2	AJDC2	31,310	6.25%	25.00%	
Better Information	**Plan**	**NPVRR**	**EP Prob**	**Probability**	**Expected Value**
High CO2	AJDC2	35,375	6.25%	25.00%	33,194
Mid	AJDC2	33,065	12.50%	50.00%	
Low CO2	AGDC2	31,273	6.25%	25.00%	
Expected Value of Better Information		9.23	Million		

Table 13: Better Information - Load

Load					
Preferred Plan	**Plan**	**NPVRR**	**EP Prob**	**Probability**	**Expected Value**
High Load	AJDC2	33,443	6.25%	25.00%	32,941
Mid	AJDC2	33,065	12.50%	50.00%	
Low Load	AJDC2	32,193	6.25%	25.00%	
Better Information	**Plan**	**NPVRR**	**EP Prob**	**Probability**	**Expected Value**
High Load	AGDC2	33,436	6.25%	25.00%	32,940
Mid	AJDC2	33,065	12.50%	50.00%	
Low Load	AJDC2	32,193	6.25%	25.00%	
Expected Value of Better Information		1.78	Million		

Table 14: Better Information - Natural Gas

Natural Gas					
Preferred Plan	**Plan**	**NPVRR**	**EP Prob**	**Probability**	**Expected Value**
High Natural Gas	AJDC2	32,543	6.25%	25.00%	32,924
Mid	AJDC2	33,065	12.50%	50.00%	
Low Natural Gas	AJDC2	33,022	6.25%	25.00%	
Better Information	**Plan**	**NPVRR**	**EP Prob**	**Probability**	**Expected Value**
High Natural Gas	AGDC2	32,470	6.25%	25.00%	32,905
Mid	AJDC2	33,065	12.50%	50.00%	
Low Natural Gas	AJDC2	33,022	6.25%	25.00%	
Expected Value of Better Information		18.46	Million		

SECTION 4: CONTINGENCY RESOURCE PLANS

The utility shall describe and document its contingency resource plans in preparation for the possibility that the preferred resource plan should cease to be appropriate, whether due to the limits identified pursuant to 4 CSR240-22.070(2) being exceeded or for any other reason.

(A) The utility shall identify as contingency resource plans those alternative resource plans that become preferred if the critical uncertain factors exceed the limits developed pursuant to section (2).22.070 (4) (A)

The company has described in the response to Rule 240-22.070(2) the only other alternative resource plan that performs better than the Preferred Plan under certain extreme risk conditions.

For KCPL the Preferred Plan and the Contingency Plan are the allocated components of the lowest-cost and contingency plans from the combined company study. KCPL Preferred Plan AGEK9 is the KCPL allocated portion of combined company plan AJDC2. KCPL Contingency Plan AAAK9 is the KCPL allocated portion of combined company plan AGDC2. Complete descriptions of the KCPL plans are located in the response to Rule 240-22.060(3) in Volume 6 of this filing. Complete descriptions of the combined company plans are located in the response to Rule 240-22.060(3)8 in Volume 6 of this filing.

(B) The utility shall develop a process to pick among alternative resource plans, or to revise the alternative resource plans as necessary, to help ensure reliable and low cost service should the preferred resource plan no longer be appropriate for any reason. The utility may also use this process to confirm the viability of contingency resource plans identified pursuant to subsection (4)(A). 22.070 (7) (B)

The process used to select alternative resource plans was derived from the analysis of the combined company results under identical risks imposed on the

KCPL stand-alone utility. The Preferred Plan was chosen as the resource plan that exhibited the lowest expected value of NPVRR given probable environmental costs. The Contingency Plan was chosen as the plan that could perform better than the Preferred Plan, should certain extreme conditions of risk factors arise. These factors are described in the response to Rule 240-22.070(2) in this Volume.

(C) Each contingency resource plan shall satisfy the fundamental objective in 4 CSR240-22.010(2) and the specific requirements pursuant to 4 CSR 240-22.070(1).

The Contingency Plan AAAK9 meets the considerations of Rule 240.22.010(2) as one of the alternative resource plans developed and conformed in the response to Rule 240-22.060(3) in Volume 6 of this filing.

As for concurrence with Rule 240.070(1), Plan AAAK9 conforms by meeting Rule 240.010(2), invests in advanced transmission and distribution technologies, utilizes the amount of DSM that conforms to legal mandates and demonstrates adequate access to emergency short-term power supply.

SECTION 5: LOAD –BUILDING PROGRAMS

Analysis of Load-Building Programs. If the utility intends to continue existing load building programs or implement new ones, it shall analyze these programs in the context of one (1) or more of the alternative resource plans developed pursuant to 4 CSR 240- 22.060(3) of this rule, including the preferred resource plan selected pursuant to 4 CSR240-22.070(1). This analysis shall use the same modeling procedure and assumptions described in 4 CSR 240-22.060(4). The utility shall describe and document—

(A) Its analysis of load building programs, including the following elements:

1. Estimation of the impact of load building programs on the electric utility's summer and winter peak demands and energy usage;

2. A comparison of annual average rates in each year of the planning horizon for the resource plan(s) with and without the load building program;

3. A comparison of the probable environmental costs of the resource plan(s) in each year of the planning horizon with and without the proposed load-building program;

4. A calculation of the performance measures and risk by year; and

5. An assessment of any other aspects of the proposed load-building programs that affect the public interest; and

(B) All current and proposed load-building programs, a discussion of why these programs are judged to be in the public interest, and, for all resource plans that include these programs, plots of the following over the planning horizon:

1. Annual average rates with and without the load-building programs; and

2. Annual utility costs and probable environmental costs with and without the load-building programs. 22.070 (5)

At this time, KCP&L does not have any load-building programs.

SECTION 6: IMPLEMENTATION PLAN

The utility shall develop an implementation plan that specifies the major tasks, schedules, and milestones necessary to implement the preferred resource plan over the implementation period. The utility shall describe and document its implementation plan, which shall contain—

6.1 LOAD ANALYSIS - SCHEDULE AND DESCRIPTION

A schedule and description of ongoing and planned research activities to update and improve the quality of data used in load analysis and forecasting;

KCP&L plans to conduct its next Residential Appliance Saturation Survey in 2013. The last such survey was completed in 2010. The results were used to calculate appliance saturations and these saturations were used to calibrate DOE forecasts of appliance saturations for use in KCP&L's load forecasting models. KCP&L also plans to match the responses with the customers' billing records and to conduct a conditional demand study to measure the unit energy consumption (UEC) for each major appliance. The last such study was conducted in 2010. The results are used to calibrate DOE forecasts of UECs for use in KCP&L's load forecasting models.

6.2 DEMAND-SIDE PROGRAMS – SCHEDULE AND DESCRIPTION

A schedule and description of ongoing and planned demand-side programs and demand-side rates, evaluations, and research activities to improve the quality of demand-side resources;

GMO has engaged Navigant Consulting to conduct a Demand-Side Management Potential study in the utility's control area The scope of work and project schedule are contained in the appendix to Volume 5 "Appendix A Navigant_SOW_Signed_01162012_HC.pdf"..

The current schedule for ongoing and planned DSM programs is shown in Table 15 below:

Table 15: DSM Program Schedule

Program Name	Program Type	New or Existing ?	Segment	Tariff Filed	EM&V plan submitted	MEEIA and DSM program approved	RFPs for new vendor selection issued	Vendor selected and contract awarded	Program Implemented	Annual Report	Evaluations Begun	EM&V Completed and report available
Low-Income Weatherization Program	Energy Efficiency	Existing	Residential	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Energy Star® New Homes Program	Energy Efficiency	Existing	Residential	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Cool Homes Program	Energy Efficiency	Existing	Residential	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Home Performance with Energy Star® Program	Energy Efficiency	Existing	Residential	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Commercial and Industrial Rebate Program Program	Energy Efficiency	Existing	C&I	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
MPower Rider	Demand Response	Existing	C&I	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Energy Optimizer Program	Demand Response	Existing	Residential	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Building Operator Certification Program	Educational	Existing	C&I	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Home Energy Analyzer Program	Educational	Existing	Residential	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Business Energy Analyzer Program	Educational	Existing	C&I	Dec-11	Dec-11	estimated by Dec 2013	N/A	N/A	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Appliance Turn-In Program	Energy Efficiency	New	Residential	Dec-11	Dec-11	estimated by Dec 2013	1 month after MEEIA approval	3 months after MEEIA approval	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Commercial and Industrial Prescriptive Rebate Program	Energy Efficiency	New	C&I	Dec-11	Dec-11	estimated by Dec 2013	1 month after MEEIA approval	4 months after MEEIA approval	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Multi-Family Rebate Progam	Energy Efficiency	New	Residential	Dec-11	Dec-11	estimated by Dec 2013	1 month after MEEIA approval	5 months after MEEIA approval	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Residential Energy Reports Program	Energy Efficiency	New	Residential	Dec-11	Dec-11	estimated by Dec 2013	1 month after MEEIA approval	6 months after MEEIA approval	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval
Residential Lighting and Appliance Program	Energy Efficiency	New	Residential	Dec-11	Dec-11	estimated by Dec 2013	1 month after MEEIA approval	7 months after MEEIA approval	6 months after MEEIA approval	12 months after MEEIA implementation	24 months after MEEIA implementation	42 months after MEEIA approval

6.3 SUPPLY-SIDE – SCHEDULES AND DESCRIPTIONS

A schedule and description of all supply-side resource research, engineering, retirement, acquisition, and construction activities, including research to meet expected environmental regulations;

KCP&L is currently in the initial stage of engaging an engineering firm to develop several supply-side related studies. This suite of studies is referred to as the "Mega Study". KCP&L has engaged Sega, Inc. to develop the scope of the Mega Study and to evaluate the responses that will be received from the Request For Proposal that will be issued. The draft timeline for the Mega Study initiative is shown in Table 16 below:

Table 16: KCP&L Mega Study Major Milestone Schedule ** Highly Confidential **

Milestone Description	Duration (work days)	Start Date	Completion Date	Total Duration (work days)	Status
[redacted]					

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The draft scope of the Mega Study is shown in Table 17 below:

Table 17: Mega Study - Montrose Station ** Highly Confidential **

Montrose Station	Retrofit
[redacted]	

Also, in anticipation of KCP&L and GMO planning jointly in the future, KCP&L and GMO are exploring the possibility of a joint Network Integrated Transmission Service Agreement ("NITSA") with SPP. Currently, KCP&L and GMO each have separate and distinct NITSAs with SPP. The NITSA provides each company the ability to flow energy from their respective generating assets to their load on firm network transmission. This arrangement does not allow the flexibility for each company to serve the other company's load under firm network transmission. With a joint NITSA, generating assets from KCP&L and GMO could be pooled under a single agreement which would allow all KCP&L and GMO assets to serve either KCP&L or GMO load under firm network transmission.

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6.4 MILESTONES AND CRITICAL PATHS

Identification of critical paths and major milestones for implementation of each demand-side resource and each supply-side resource, including decision points for committing to major expenditures;

Critical paths and major milestones for implementation of each demand-side resource are shown above, in Section 6.2

On May 6, 2011, KCP&L entered into a PPA agreement with CPV Cimarron II Renewable Energy Company, LLC, whose parent company was Competitive Power Ventures, to purchase energy from a 131.1 MW wind project located in Gray County, Kansas. The project was subsequently sold to a subsidiary of Duke Energy Renewables. The facility is expected to be in-service by May 31, 2012. Table 18 provides a milestone schedule of activities.

Table 18: Cimarron II Schedule

Cimarron II Wind Project	
Activity	**Milestone Date**
PPA Signed	05/06/11
Construction Began	09/06/11
Last Turbine Erected	04/18/12
Substation Complete	04/04/12
First Turbine On-Line	04/10/12
Last Turbine On-line	05/31/12
Project Complete	06/15/12

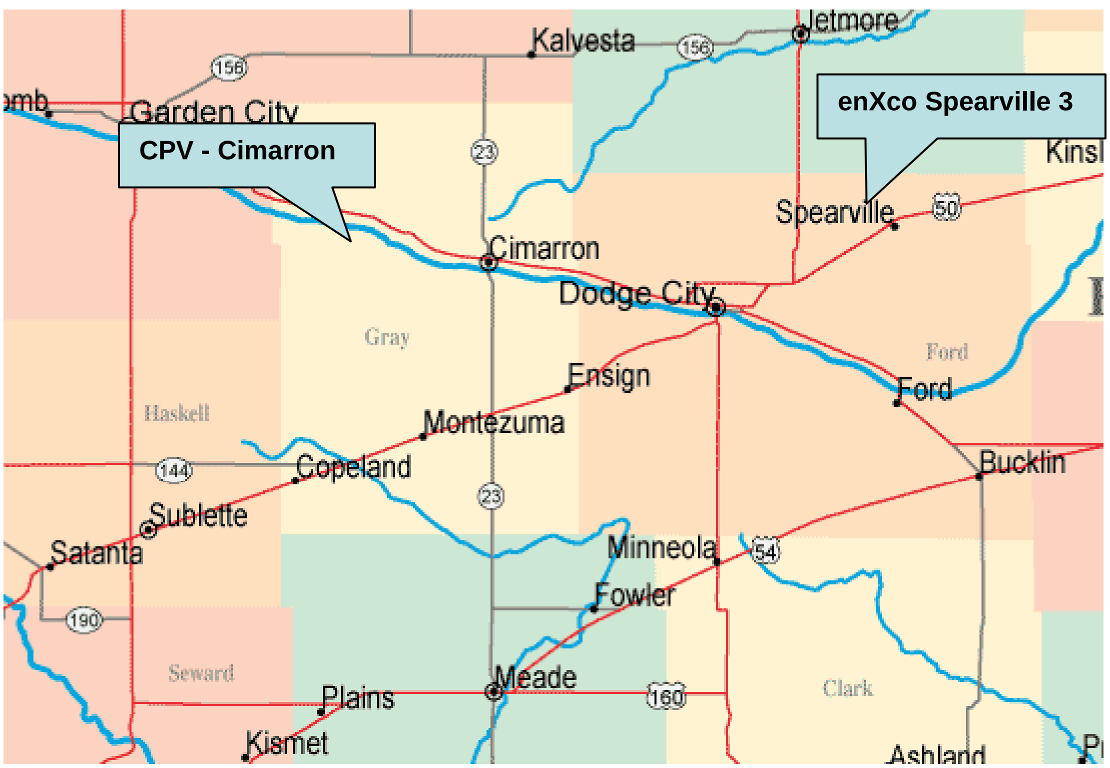
On November 3 2011, KCP&L entered into a PPA agreement with Spearville 3 LLC, whose parent company is enXco Development, to purchase energy from a 100.8 MW wind project located in Ford County, Kansas. The facility is expected to be in-service by August 31, 2012. Table 19 provides a milestone schedule of activities.

Table 19: Spearville 3 Schedule

Spearville 2 Project	
Activity	**Milestone Date**
PPA Signed	**11/03/11**
Construction Began	**03/12/12**
Last Turbine Erected	**08/15/12**
Substation Complete	**07/20/12**
First Turbine On-Line	**07/23/12**
Last Turbine On-line	**08/31/12**
Project Complete	**09/30/12**

Table 20 shows the location of these wind projects:

Table 20: Location of 2012 Wind PPA projects



6.5 <u>COMPETITIVE PROCUREMENT POLICIES</u>

A description of adequate competitive procurement policies to be used in the acquisition and development of supply-side resources;22.070 (6) (E)

KCP&L does not anticipate requiring any supply-side resources including PPA's in the Implementation Period.

6.6 MONITORING CRITICAL UNCERTAIN FACTORS

A process for monitoring the critical uncertain factors on a continuous basis and reporting significant changes in a timely fashion to those managers or officers who have the authority to direct the implementation of contingency resource plans when the specified limits for uncertain factors are exceeded; and 22.070 (7) (F)

Each critical uncertain factor is reviewed on an individual basis due to the varied nature of the information sources used in its review. This IRP analysis will be updated on an annual basis reflecting any changes to these critical uncertain factors. Results will be distributed to the Senior V.P. of Supply.

Critical Uncertain Factor: CO_2

CO_2 credit prices are reviewed on a continual basis. The data sources used are third party views predicting the price of the credits. Most of these third party studies are sparked by proposed legislation or are updated up to a quarterly basis. This review and update is conducted by the Fuels department with a full review conducted on an annual basis.

Critical Uncertain Factor: Construction Costs

Construction costs are updated as new information comes in from sources such as EPRI TAG, published third party reports, RFP responses, etc. This review and updating is a continual process.

Critical Uncertain Factor: Load

Load forecasts are updated on an annual basis as part of the company's annual budgeting process.

Critical Uncertain Factor: Natural Gas

Natural Gas forecasts are updated weekly with executive updates provided on a monthly basis.

Critical Uncertain Factor: Financial Drivers

Financial measures are updated annually as part of the annual budget process.

Market conditions may change the time frame under which a new review of any of these aforementioned forecasts would occur.

6.7 MONITORING PREFERRED RESOURCE PLAN

A process for monitoring the progress made implementing the preferred resource plan in accordance with the schedules and milestones set out in the implementation plan and for reporting significant deviations in a timely fashion to those managers or officers who have the authority to initiate corrective actions to ensure the resources are implemented as scheduled.22.070 (7) (G)

KCP&L has processes in place to monitor its Demand-Side Management programs and track and report their performance compared to the planned implementation schedule.

There are no supply-side resource additions during the Implementation Period.

SECTION 7: RESOURCE ACQUISITION STRATEGY

The utility shall develop, describe and document, officially adopt, and implement a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by an officer of the utility who has been duly delegated the authority to commit the utility to the course of action described in the resource acquisition strategy. The officially adopted resource acquisition strategy shall consist of the following components:

7.1 PREFERRED RESOURCE PLAN

(A) A preferred resource plan selected pursuant to the requirements of section (1) of this rule;22.070 (7) (A)

The Preferred Resource Plan is outlined in Section 1 above per Rule 240-22.070(1)

7.2 IMPLEMENTATION PLAN

(B) An implementation plan developed pursuant to the requirements of section (6) of this rule; and 22.070 (7) (B)

The Implementation Plan is outlined in Section 6 above per Rule 240-22.070(6)

7.3 CONTINGENCY RESOURCE PLANS

(C) A set of contingency resource plans developed pursuant to the requirements of section (4) of this rule and identification of the point at which the critical uncertain factors would trigger the utility to move to each contingency resource plan as the preferred resource plan. 22.070 (7) (C)

The Contingency Resource Plan is outlined in Section 4 above per Rule 240-22.070(4).

KANSAS CITY POWER & LIGHT COMPANY

2012 INTEGRATED RESOURCE PLAN

CORPORATE APPROVAL STATEMENT FOR

RESOURCE ACQUISITION STRATEGY

In accordance with Missouri Public Service Commission rules found in 4 CSR 240-22, Kansas City Power & Light Company ("KCP&L") developed, described and documented, and now officially adopts for implementation the resource acquisition strategy contained in this filing.

As required in 4 CSR 240-22.070(7), the resource acquisition strategy consists of a preferred resource plan; an implementation plan; and a set of contingency resource plans and identification of the point at which the critical uncertain factors would trigger KCP&L to review each contingency resource plan as the preferred resource plan.

Terry D. Bassham

President and Chief Operating Officer

Scott Heidtbrink

Scott H. Heidtbrink

Senior Vice President—Supply

SECTION 8: EVALUATION OF DEMAND-SIDE PROGRAMS AND DEMAND-SIDE RATES

The utility shall describe and document its evaluation plans for all demand-side programs and demand-side rates that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(1). Evaluation plans required by this section are for planning purposes and are separate and distinct from the evaluation, measurement, and verification reports required by 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7); nonetheless, the evaluation plan should, in addition to the requirements of this section, include the proposed evaluation schedule and the proposed approach to achieving the evaluation goals pursuant to 4 CSR 240-3.163(7) and 4 CSR 240-20.093(7). The evaluation plans for each program and rate shall be developed before the program or rate is implemented and shall be filed when the utility files for approval of demand-side programs or demand-side program plans with the tariff application for the program or rate as described in 4 CSR 240-20.094(3). The purpose of these evaluations shall be to develop the information necessary to evaluate the cost-effectiveness and improve the design of existing and future demand-side programs and demand-side rates, to improve the forecasts of customer energy consumption and responsiveness to demand-side programs and demand-side rates, and to gather data on the implementation costs and load impacts of demand-side programs and demand-side rates for use in future cost-effectiveness screening and integrated resource analysis.

KCP&L will prepare a request for proposal (“RFP”) to conduct an evaluation, measurement and verification (“EM&V”) of all demand-side programs and demand-side rates that are included in KCP&L’s preferred resource plan.

<u>EM&V Process Evaluation</u>

The scope of work for the RFP will require that the Vendor conduct a process evaluation pursuant to requirements of 4 CSR 240-22.070 (8) (A) and require the

Vendor to provide answers to questions 1 through 5 of this rule section in the EM&V final report ("Report").

EM&V Impact Evaluation

The scope of work for the EM&V RFP will require that the Vendor conduct the impact evaluation pursuant to requirements of 4 CSR 240-22.070 (8) (B) and require the Vendor to provide answers to questions 1 and 2 of this rule section in the Report.

EM&V Data Collection

The scope of work for the EM&V RFP will require that the Vendor collect EM&V participation rate data, utility cost data, participant cost data and total cost data pursuant to requirements of 4 CSR 240-22.070 (8) (C).

KCP&L will develop protocols and design a business process to collect the program participant data required pursuant to the requirements of 4 CSR 240-22.070 (8) (C).

KCP&L has engaged a consulting firm, Navigant, Inc., to conduct a potential study and to collect data market potential data pursuant to the requirements of 4 CSR 240-22.070 (8) (C).

EM&V Reporting Requirements

The scope of work for the EM&V RFP will also require that the Vendor perform, and report EM&V of each commission-approved demand-side program in accordance with 4 CSR 240-3.163 (7).

KCP&L will provide the Missouri Public Service Commission ("Commission") Staff and other stakeholders with an opportunity to review and comment on the RFP and to also review and comment on a proposed list of potential vendors that have experience conducting demand-side program and demand-side rate EM&Vs prior to issuance of the EM&V RFP.

The proposed EM&V RFP and the proposed list of vendors will be available for Commission staff and stakeholder review three months after Commission approval of these demand-side resources pursuant to 4 CSR 240-20.094 and the approval KCP&L's demand-side program investment mechanism ("DSIM") pursuant to 4 CSR 240-20.093 ("Approval Date").

KCP&L will conduct a workshop to review the proposed EM&V RFP and vendor list and to provide stakeholders with an opportunity to present questions, or offer comments or suggestions prior to issuance of the RFP. The proposed RFP may be modified to incorporate any important issues or concerns raised by the Commission staff or stakeholders. The EM&V RFP will be issued five months after the Commission Approval Date. Vendor selection will be six months after the Commission Approval Date.

An evaluation, measurement and verification ("EM&V") for all demand-side programs and demand-side rates that are included in KCP&L's preferred resource plan will begin seven months after the Commission Approval Date.

The EM&V RFP will require the selected vendor to evaluate and prepare an annual program performance report. The first annual report will be available twelve months after the Approval Date. The second annual report will be available twenty-four months after the Approval Date.

Preliminary EM&V reports will be available thirty months after the Commission Approval Date. Commission Staff and stakeholders will be provided with an opportunity to review, and comment on the preliminary report.

The final EM&V report will be available thirty-three months after the Commission Approval Date. Commission Staff and stakeholders will be provided with an opportunity to review, and comment on the preliminary report.

<u>EM&V Schedule and Budget</u>

The EM&V budget shall not exceed five percent (5%) of the total budget for all approved demand-side program costs. The EM&V schedule is shown in Table 21 below.

Table 21: Evaluation Schedule

EM&V Schedule	
Commission DSM / DSIM Approval Date	Estimated by December 2013
Proposed EM&V RFP available for review	3 months after Commission Approval Date
Review of stakeholder questions, comments and suggestions.	4 months after Commission Approval Date
Issuance of EM&V RFP	5 months after Commission Approval Date
EM&V vendor selected	6 months after Commission Approval Date
EM&V begins	7 months after Commission Approval Date
1st Annual Program Report	12 months after Commission Approval Date
2nd Annual Program Report	24 months after Commission Approval Date
Preliminary review of EM&V results	30 months after Commission Approval Date
EM&V Final Report available.	33 months after Commission Approval Date

8.1 PROCESS EVALUATION

(A) Each demand-side program and demand-side rate that is part of the utility's preferred resource plan shall be subjected to an ongoing evaluation process which addresses at least the following questions about program design.
22.070 (8) (A)

1. What are the primary market imperfections that are common to the target market segment?22.070 (8) (A) 1.
See the response to Section 8, above.

2. Is the target market segment appropriately defined, or should it be further subdivided or merged with other market segments?
22.070 (8) (A) 2.

See the response to Section 8, above.

3. Does the mix of end-use measures included in the program appropriately reflect the diversity of end-use energy service needs and existing end-use technologies within the target market segment?
22.070 (8) (A) 3.

See the response to Section 8, above.

4. Are the communication channels and delivery mechanisms appropriate for the target market segment?
22.070 (8) (A) 4.

See the response to Section 8, above.

5. What can be done to more effectively overcome the identified market imperfections and to increase the rate of customer acceptance and implementation of each enduse measure included in the program?
22.070 (8) (A) 5.

See the response to Section 8, above.

8.2 <u>IMPACT EVALUATION</u>

(B) The utility shall develop methods of estimating the actual load impacts of each demand-side program and demand-side rate included in the utility's preferred resource plan to a reasonable degree of accuracy.
22.070 (8) (B)

1. Impact evaluation methods. At a minimum, comparisons of one (1) or both of the following types shall be used to measure program and rate impacts in a manner that is based on sound statistical principles:

A. Comparisons of pre-adoption and post-adoption loads of program or demand-side rate participants, corrected for the effects of weather and other intertemporal differences; and
22.070 (8) (B) 1. A.

See the response to Section 8, above.

B. Comparisons between program and demand-side rate participants' loads and those of an appropriate control group over the same time period.
22.070 (8) (B) 1. B.

See the response to Section 8, above.

2. The utility shall develop load-impact measurement protocols that are designed to make the most cost-effective use of the following types of measurements, either individually or in combination:

A. Monthly billing data, hourly load data, load research data, end-use load metered data, building and equipment simulation models, and survey responses; or

22.070 (8) (B) 2. A.See the response to Section 8, above.

B. Audit and survey data on appliance and equipment type, size and efficiency levels, household or business characteristics, or energy-related building characteristics.

22.070 (8) (B) 2. B.See the response to Section 8, above.

8.3 DATA COLLECTION PROTOCOLS

(C) The utility shall develop protocols to collect data regarding demand-side program and demand-side rate market potential, participation rates, utility costs, participant costs, and total costs.

22.070 (8) (C)

See the response to Section 8, above.