Public

AmerenUE

Integrated Resource Plan

4 CSR 240-22.040

Supply-Side Resource Analysis

Volume 2

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4 CSR 240-22.040 (2)

Each of the supply-side resource options referred to in section (1) shall be subjected to a preliminary screening analysis. The purpose of this step is to provide an initial ranking of these options based on their relative annualized utility costs as well as their probable environmental costs and to eliminate from further consideration those options that have significant disadvantages in terms of utility costs, environmental costs, operational efficiency, risk reduction or planning flexibility, as compared to other available supply-side resource options. All costs shall be expressed in nominal dollars.

Each of the technologies addressed in 22.040 Section (1) was subjected to a preliminary screening analysis. In addition to these technologies, options provided by AmerenUE to Black & Veatch were considered in the preliminary screening analysis. These options are the following:

- US EPR Nuclear.
- Venice Combined Cycle.
- Church Mountain Pumped Storage.

The preliminary screening analysis provided an initial ranking of the technologies, based on the characteristics provided in response to the requirements of 22.040 Section (1). A scoring methodology was developed with the intent to compare the different technologies within their dispatch group by an overall weighted score. This score was developed for each technology by comparing the following categories: utility cost, environmental cost, risk reduction, planning flexibility, and operability. Criteria within those categories were established, and numerical scores were assigned based on differentiating qualitative technology characteristics. Criteria were established based on Black & Veatch's experience, with consideration for AmerenUE's planning needs. These criteria are show in Table 58. The scoring for each of the technologies is shown in the Scoring Table of 4 CSR 240-22.040 Appendix D. The scoring for each of the renewable technologies is shown in 4 CSR 240-22.040 Appendix E.

Table 58
Scoring Criteria

Category/Criteria	Category/Criteria Weighting	Scoring Basis Guidelines
Utility Cost	**35**	
Levelized cost of energy	90	100 - Lower 5 percentile. 90 to 10 - 5 to 95 percentile, linearly scaled. 0 - Upper 5 percentile.
Specificity of location	10	100 - Within AmerenUE service territory. 50 - Within Midwest Independent System Operator. 0 - Outside Midwest Independent System Operator.
Environmental Cost	**20**	
Currently meets regulated emission limits	60	100 - Produces no emissions. 85 - Ability to meet emission limits. 0 - Inability to meet emission limits.
Potential for future addition of more stringent control technologies and level of control	40	100 - Would not require any future controls for any major pollutants. 75 - May require future controls for two major pollutants. 25 - May require future controls for three or four major pollutants. 0 - May require future controls for five or more major pollutants.
Risk Reduction	**15**	
Technology status	60	100 - Commercially proven. 50 - Demonstration. 25 - Developmental with positive trend. 0 - Developmental with negative trend.
Constructability	20	100 - Less labor, material and equipment availability risk. 50 - Moderate labor, material and equipment availability risk. 25 - More labor, material and equipment availability risk.
Safety training requirements	20	100 - Minimal safety training requirements and hazards. 50 - Industry standard for baseload generation in safety training and hazards. 0 - Unique training requirements and/or hazards.
Planning Flexibility	**15**	
Permitting	10	100 - Less extensive permitting. 50 - Moderate permitting. 25 - More extensive permitting.
Schedule Duration	10	100 - Lower 5 percentile. 90 to 10 - 5 to 95 percentile, linearly scaled. 0 - Upper 5 percentile.
Fuel Flexibility	25	100 - No fuel required. 50 - Multiple fuels, multiple sources. 25 - Multiple fuels & single source or single fuel & multiple sources. 0 - Single fuel, single source.
Scalability/Modularity/Resource Constrained	20	100 - Has no constraints. 75 - Has one constraint. 25 - Has two constraints. 0 - Is constrained by scalability, modularity, and resource availability.
Transmission Complexity	15	100 - Requires less redundancy, less planning required. 50 - Require more redundancy, more planning required.
Construction Schedule and Budget Risk	20	100 - Cost or schedule uncertainty. 75 - Cost and schedule uncertainty. 50 - Cost and schedule uncertainty with limited industry experience. 25 - Major cost and schedule uncertainty. 0 - Major cost and schedule uncertainty with limited industry experience.
Operability	**15**	
Availability	50	100 - Equivalent Availability factor 85 percent or greater. 50 - Equivalent Availability factor less than 85 percent.
Technical Operability Training	15	100 - Minimal technical operability management. 50 - Moderate technical operability management. 25 - Moderate technical operability management and advanced technology. 0 - Unique experience and management requirements for operation.
Load-Following/VAR Support	35	100 - Load-following and reactive power support capabilities. 50 - Load-following or reactive power support capabilities. 25 - Moderate load-following or reactive power support capabilities. 0 - Inability or constraints to load-following and reactive power support capabilities.

4 CSR 240-22.040 (2)(A)

Cost rankings shall be based on estimates of the installed capital costs plus fixed and variable operation and maintenance costs levelized over the useful life of the resource using the utility discount rate. In lieu of levelized cost, the utility may use an economic carrying charge annualization in which the annual dollar amount increases each year at an assumed inflation rate and for which a stream of these amounts over the life of the resource yields the same present value.

One of the more significant inputs to the scoring was the utility cost. This was calculated as a levelized busbar cost of energy using many of the data presented in 22.040 (1)(A) through (K). In addition, economic criteria for useful life, Owner's costs, present worth discount rate, levelized fixed charge rate, and escalation were also assumed or calculated to support the busbar cost analysis. These inputs are summarized in the Characterization Table of 4 CSR 240-22.040 Appendix A for fossil fuel resources, and of 4 CSR 240-22.040 Appendix B for renewable and energy storage resources.

A sample busbar cost calculation is presented on Figure 1. Annual costs include levelized annual capital cost, fixed and variable O&M, fuel, and emissions allowances. In this case, the 40 year sum of the net present worth (PW) costs is divided by the sum of a series of present worth values, which is determined using the present worth discount factor. Annual cost projections for CO_2 emissions have been added to the busbar cost calculations in some of the analysis cases run for this study.

Plant Input Data		Economic Input Data	Rate	Escalation
Capital Cost ($ 1,000)	1,290,000	First Year Fixed O&M ($ 1,000)	11,070.0	2.5%
Total Net Capacity (kW)	500,000	First Year Variable O&M ($/MWh)	2.03	2.5%
Capacity Factor	$\boxed{85.0\%}$	Fuel Rate	1.80	2.5%
Full Load Heat Rate, Btu/kWh (HHV)	9,050			
		Present Worth Discount Rate	8.9%	
(Note: There are 8760 hours in a year)		Levelized Fixed Charge Rate	13.570%	

Year	Capital ($1,000)	Fixed O&M ($1,000)	Variable O&M ($1,000)	Fuel Rate ($/MBtu)	Fuel Cost ($1,000)	Emissions Allow ($1,000)	Total Cost ($1,000)	PW Total Cost ($1,000)	Other ($1,000)	Other ($1,000)	Busbar Cost (¢/kWh)	Net PW Cost ($1,000)
1	175,053	11,070	7,558	[redacted]			254,756	233,936			6.84	6.28
2	175,053	11,347	7,747	[redacted]			256,760	216,506			6.90	5.82
3	175,053	11,630	7,940	[redacted]			258,814	200,403			6.95	5.38
4	175,053	11,921	8,139	[redacted]			260,920	185,522			7.01	4.98
5	175,053	12,219	8,342	[redacted]			263,079	171,770			7.07	4.61
6	175,053	12,525	8,551	[redacted]			265,293	159,059			7.13	4.27
7	175,053	12,838	8,765	[redacted]			267,563	147,310			7.19	3.96
8	175,053	13,159	8,984	[redacted]			269,891	136,447			7.25	3.66
9	175,053	13,488	9,208	[redacted]			272,277	126,404			7.31	3.40
10	175,053	13,825	9,439	[redacted]			274,724	117,116			7.38	3.15
11	175,053	14,171	9,674	[redacted]			277,233	108,527			7.45	2.92
12	175,053	14,525	9,916	[redacted]			279,805	100,582			7.52	2.70
13	175,053	14,888	10,164	[redacted]			282,443	93,233			7.59	2.50
14	175,053	15,260	10,418	[redacted]			285,148	86,433			7.66	2.32
15	175,053	15,642	10,679	[redacted]			287,921	80,141			7.73	2.15
16	175,053	16,033	10,946	[redacted]			290,764	74,318			7.81	2.00
17	175,053	16,433	11,219	[redacted]			293,680	68,929			7.89	1.85
18	175,053	16,844	11,500	[redacted]			296,670	63,940			7.97	1.72
19	175,053	17,265	11,787	[redacted]			299,736	59,321			8.05	1.59
20	175,053	17,697	12,082	[redacted]			302,880	55,044			8.14	1.48
21	175,053	18,139	12,384	[redacted]			306,103	51,084			8.22	1.37
22	175,053	18,593	12,694	[redacted]			309,409	47,415			8.31	1.27
23	175,053	19,058	13,011	[redacted]			312,799	44,017			8.40	1.18
24	175,053	19,534	13,336	[redacted]			316,275	40,869			8.50	1.10
25	175,053	20,023	13,670	[redacted]			319,839	37,952			8.59	1.02
26	175,053	20,523	14,012	[redacted]			323,495	35,249			8.69	0.95
27	175,053	21,036	14,362	[redacted]			327,244	32,743			8.79	0.88
28	175,053	21,562	14,721	[redacted]			331,088	30,420			8.89	0.82
29	175,053	22,101	15,089	[redacted]			335,030	28,267			9.00	0.76
30	175,053	22,654	15,466	[redacted]			339,074	26,270			9.11	0.71
31	175,053	23,220	15,853	[redacted]			343,220	24,418			9.22	0.66
32	175,053	23,801	16,249	[redacted]			347,472	22,700			9.33	0.61
33	175,053	24,396	16,655	[redacted]			351,834	21,107			9.45	0.57
34	175,053	25,005	17,072	[redacted]			356,306	19,628			9.57	0.53
35	175,053	25,631	17,498	[redacted]			360,893	18,256			9.69	0.49
36	175,053	26,271	17,936	[redacted]			365,598	16,982			9.82	0.46
37	175,053	26,928	18,384	[redacted]			370,424	15,800			9.95	0.42
38	175,053	27,601	18,844	[redacted]			375,373	14,703			10.08	0.39
39	175,053	28,291	19,315	[redacted]			380,449	13,684			10.22	0.37
40	175,053	28,999	19,798	[redacted]			385,655	12,737			10.36	0.34
								Net Levelized Bus-bar Cost (¢/kWh)				7.51
								Net Levelized Cost ($1,000)				279,732

Figure 1
Sample Levelized Busbar Cost Calculation

Levelized busbar costs were calculated for all of the technologies. These busbar costs represent the utility of cost of energy. Full tabular results are provided in the Characterization Table of 4 CSR 240-22.040 Appendix A . Figure 2 presents the results graphically.

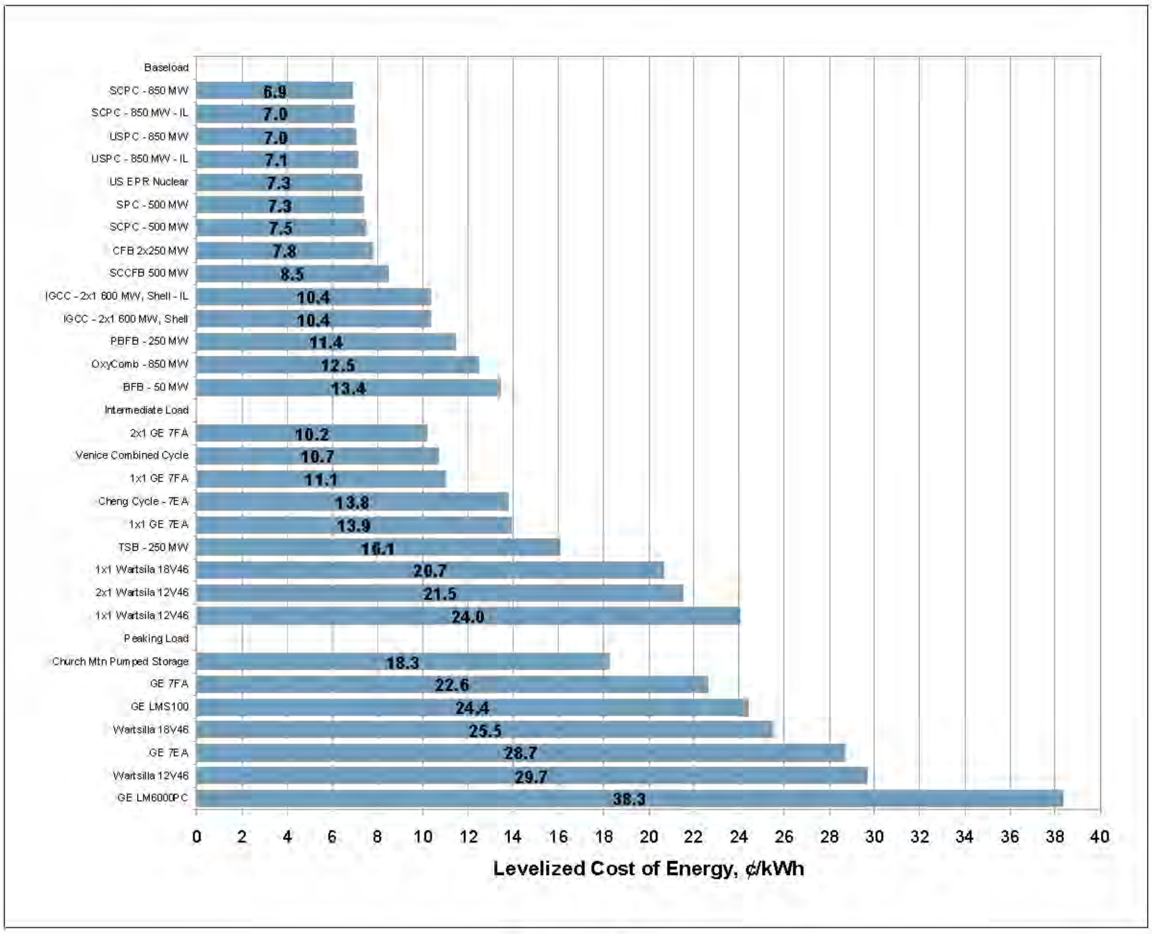

Figure 2
Utility Cost Ranking Exclusive of Environmental Costs

For renewable and energy storage resources, full tabular results are provided in the characterization Table of 4 CSR 240-22.040 Appendix B. Figure 3 presents the results graphically.

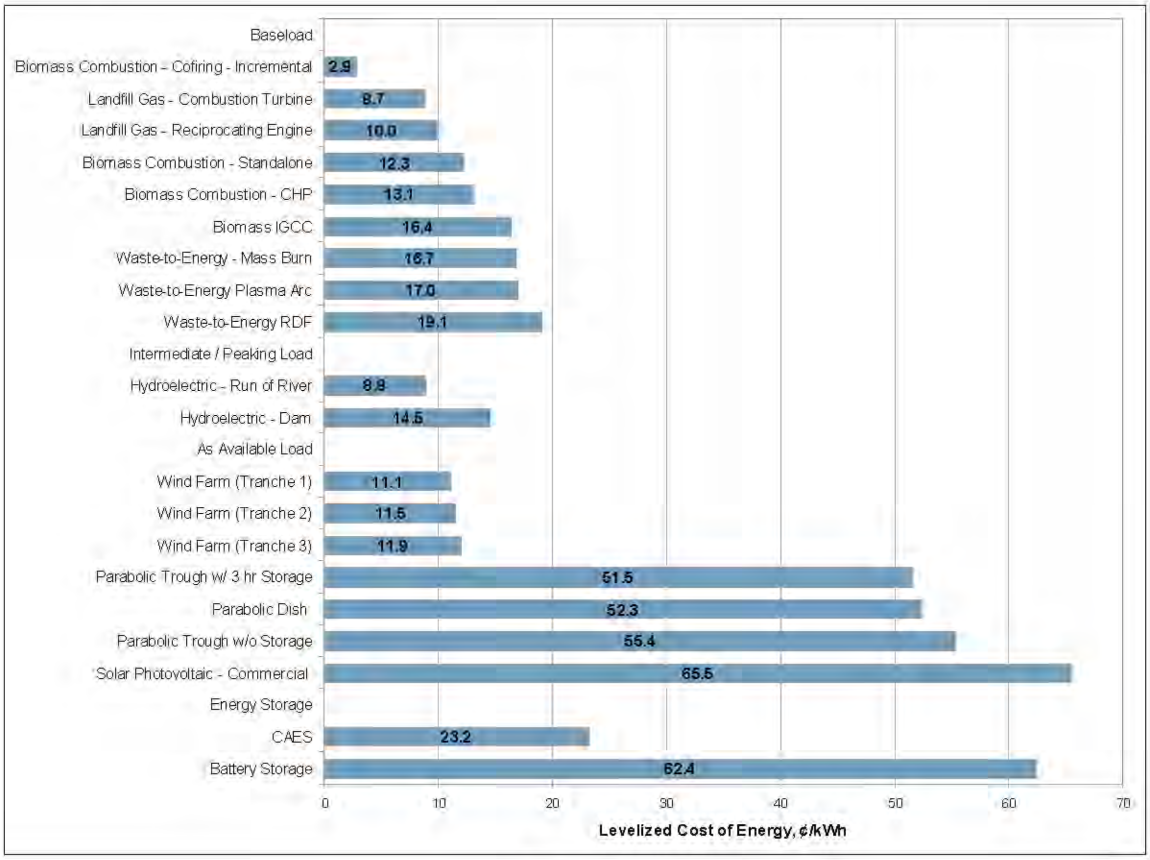

Figure 3
Utility Cost Ranking

4 CSR 240-22.040 (2)(B)

The probable environmental costs of each supply-side resource option shall be quantified by estimating the cost to the utility to comply with additional environmental laws or regulations that may be imposed at some point within the planning horizon.

As noted in the previous section, the busbar cost calculation can be configured to include annual costs that are in addition to capital, O&M, and fuel. These would include emissions allowances on regulated pollutants and potential costs for CO_2 emissions. Currently, these costs are speculative, since no regulation is in place to cause such a value to exist. The environmental costs for renewable and energy storage technologies are all small or zero.

4 CSR 240-22.040 (2)(B)1

The utility shall identify a list of environmental pollutants for which, in the judgment of utility decision-makers, additional laws or regulations may be imposed at some point within the planning horizon which would result in compliance costs that could have a significant impact on utility rates.

Carbon policy constitutes the most influential uncertain factor affecting the supply-side complexion of potential resource plans. The abatement proposals currently circulating in Congress vary greatly in form, coverage, and, most importantly, stringency. With varying degrees of mitigation come varying estimates of the costs to vital components of the U.S. economy, including the electricity generation sector (By rule of thumb, a modest CO_2 price of [redacted] per short ton of CO_2 emitted would result in an increase in the dispatch cost of coal-fired electricity of $5 per MWh produced, which would have obvious impacts on AmerenUE retail electricity rates.). AmerenUE expects that the proposals with the highest chance of political passage will be those that achieve meaningful, yet attainable, reductions in CO2 emissions while minimizing the burden on the most vulnerable sectors of the economy. The added costs of even a CO2 policy exclusively targeting electricity generation will surely ripple through other energy-intensive sectors, including such entrenched industries as vehicle manufacturing, heavy industry (steel), and high-end technology services. Through this lens, AmerenUE experts were able to assess a threshold for the political willingness to pay to reduce CO2 emissions. At the same time, AmerenUE management acknowledged a significant likelihood for some form of mandatory carbon abatement within the planning horizon

The likely impact of potential changes in three-pollutant (SO2, NOX, and Hg) emissions caps over the next twenty years is negligible, especially in the shadow of the climate change debate. For one, SO2 and NOX emissions caps were very recently tightened, and the first ever Hg reduction mandates have just been approved and do not become effective until 2010. Moreover, the present intense demand for retrofit capacity tempers enthusiasm for demanding even more in the near future. Second, preliminary modeling results indicate that wide variations in three-pollutant prices have very little impact on IRP-relevant inputs and outputs, particularly electricity prices and load growth. The disposition of new generating technologies, in turn, is invariant to the stringency of potential three-pollutant policies. This is in stark contrast to the case outlined above for CO2 policy. In fact, previous CRA experience has repeatedly demonstrated that three pollutant prices are actually more sensitive to carbon price policy changes than to further modifications to their own caps, improbable as those modifications may be. In constructing a probability tree that incorporates a reasonable range of the uncertainty in CO2 prices, the scenarios from which resource plans are generated capture multiple levels of three-pollutant allowance prices. Therefore, changes to emissions policy costs outside of CO2 are not judged to satisfy the criteria in section 4 CSR 240-22.040 (2) (B) 1.

<u>Fossil Fuel & Nuclear Resources</u>

With estimated or forecasted of allowance costs for NO_X, SO_2, mercury, and CO_2 for use in this study, values were provided for the Business As Usual (BAU) and \$15 CO_2 cases. These are shown in Table 59.

Another set of busbar costs was generated to include the environmental mitigation costs. These tabular results are included in the Characterization Table of 4 CSR 240-22.040 Appendix A (Characterization Table), along with the utility cost-only cases from the previous section. The busbar with environmental mitigation costs are graphically represented on Figure 4. Busbar cost for technologies with CO_2 mitigation, carbon capture and compression, are provided in a separate figure. Figure 5 graphically displays busbar cost for technologies with CO_2 mitigation including environmental mitigation costs.

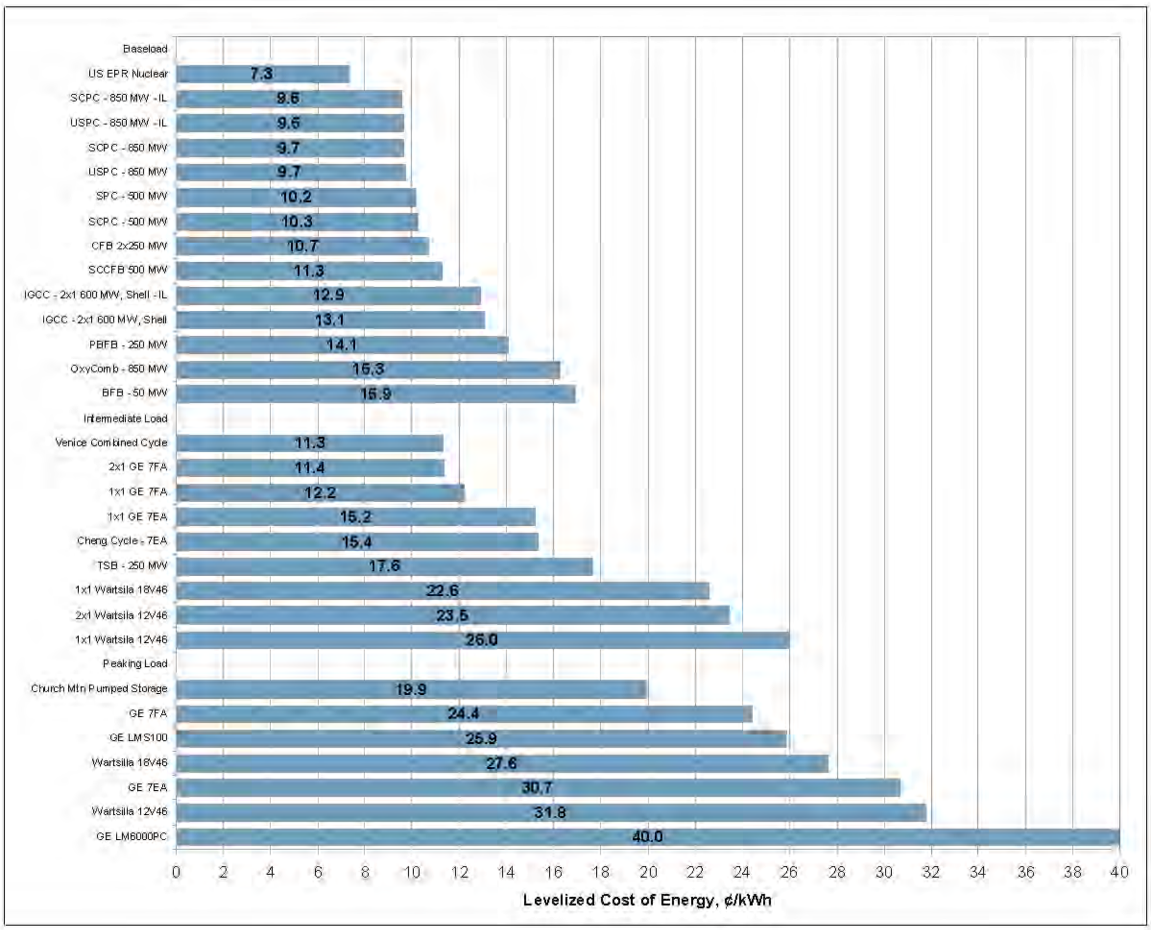

Figure 4
Utility Cost Ranking with Environmental Costs

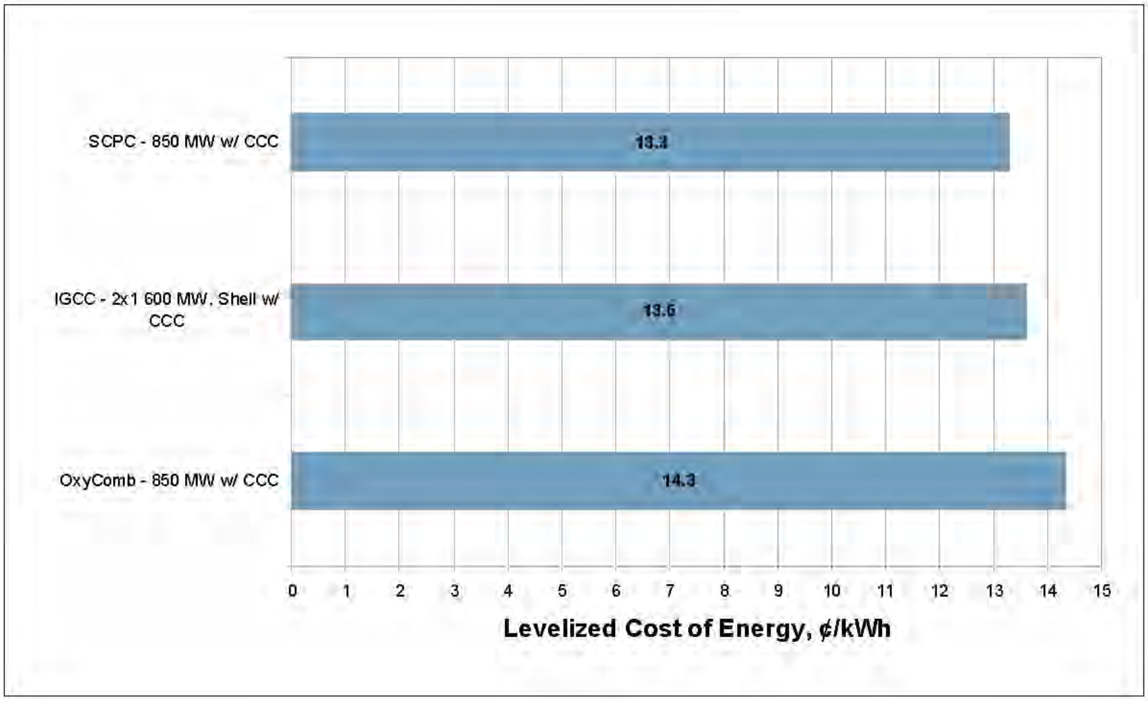

Figure 5
CO_2 Mitigation Technology Utility Cost Ranking with Environmental Costs

Table 59 Emissions Allowance and CO_2 Cost Forecast							
	BAU Case			$15 CO_2 Case			
Year	SO_2, $/ton	NO_x, $/ton	Mercury, $/lb	SO_2, $/ton	NO_x, $/ton	Mercury, $/lb	CO_2, $/ton
2007	[redacted]						
2008	[redacted]						
2009	[redacted]						
2010	[redacted]						
2011	[redacted]						
2012	[redacted]						
2013	[redacted]						
2014	[redacted]						
2015	[redacted]						
2016	[redacted]						
2017	[redacted]						
2018	[redacted]						
2019	[redacted]						
2020	[redacted]						
2021	[redacted]						
2022	[redacted]						
2023	[redacted]						
2024	[redacted]						
2025	[redacted]						
2026	[redacted]						
2027	[redacted]						
2028	[redacted]						
2029	[redacted]						
2030	[redacted]						

Renewable and Energy Storage Resources

No additional busbar costs were generated for the renewable and energy storage technologies to include the cost of emissions. As mentioned in the previous section, emission allowance costs are speculative, since no regulations are in place.

4 CSR 240-22.040 (2)(B)2

For each pollutant identified pursuant to paragraph (2)(B)1., the utility shall specify at least two (2) levels of mitigation that are more stringent than existing requirements which are judged to have a nonzero probability of being imposed at some point within the planning horizon.

The general principles governing the creation of an IRP probability tree are what shaped the CO_2 mitigation paths. The first step is to evaluate what the scenarios, as a group, need to capture to adequately inform resource plan selection. In short, they ought to span the full range of outcomes that could alter the preferred resource plan, but within a reasonable range of likelihood. As a general rule, then, AmerenUE attempted to avoid creating branches that have very small probability (that is, less than 5%) relative to other branches for that same variable. Among the leading resource plan, scenarios representing such extremely improbable events would be unlikely to alter choices under uncertainty. Second, for critical uncertain factors determined by policy decisions (*e.g.*, CO_2 prices), probabilities are constrained more by political feasibility than by physical limits or even by advocates' proposals. As the economic impact estimates for the current and future proposals are flushed out, and the true magnitude of the net societal costs becomes clear, a greater resolution of political will can be reliably expected. Thus, the CO_2 abatement requirements that end up being promulgated may be determined more by a political willingness to pay than by any scientific need.

Given the uncertainty in CO_2 prices in cap-and-trade schemes, it is much easier to simulate the range of political realities with a CO_2 price path. AmerenUE decided that a high and a moderate set of CO_2 prices would adequately reflect the full uncertainty in carbon policy. Figure 6 depicts the two CO_2 price paths that comprise the market-based CO_2 policy branches of the probability tree. The yellow and pink lines represent the high and moderate CO_2 price cases, respectively. The high CO_2 price case assumes an initial CO_2 price in 2012 of [redacted] per short ton, in nominal dollars, increasing through the model horizon at [redacted] annually in real terms. The moderate CO_2 price case assumes a 2012 CO_2 price of [redacted] per short ton, in nominal dollars, again increasing at [redacted] annually in real terms. AmerenUE management and stakeholders deemed that these two cases encompass the full breadth of potential CO_2 prices over the planning horizon. Note that from the perspective of assigning subjective probabilities, each of these cases reflects a range of values around the given trajectory. As such, the CO_2 policy branches depicted below do not reject the possibility of 2012 CO_2 prices above [redacted] or below [redacted] but instead offer a representative range of politically probable CO_2 trading regimes.

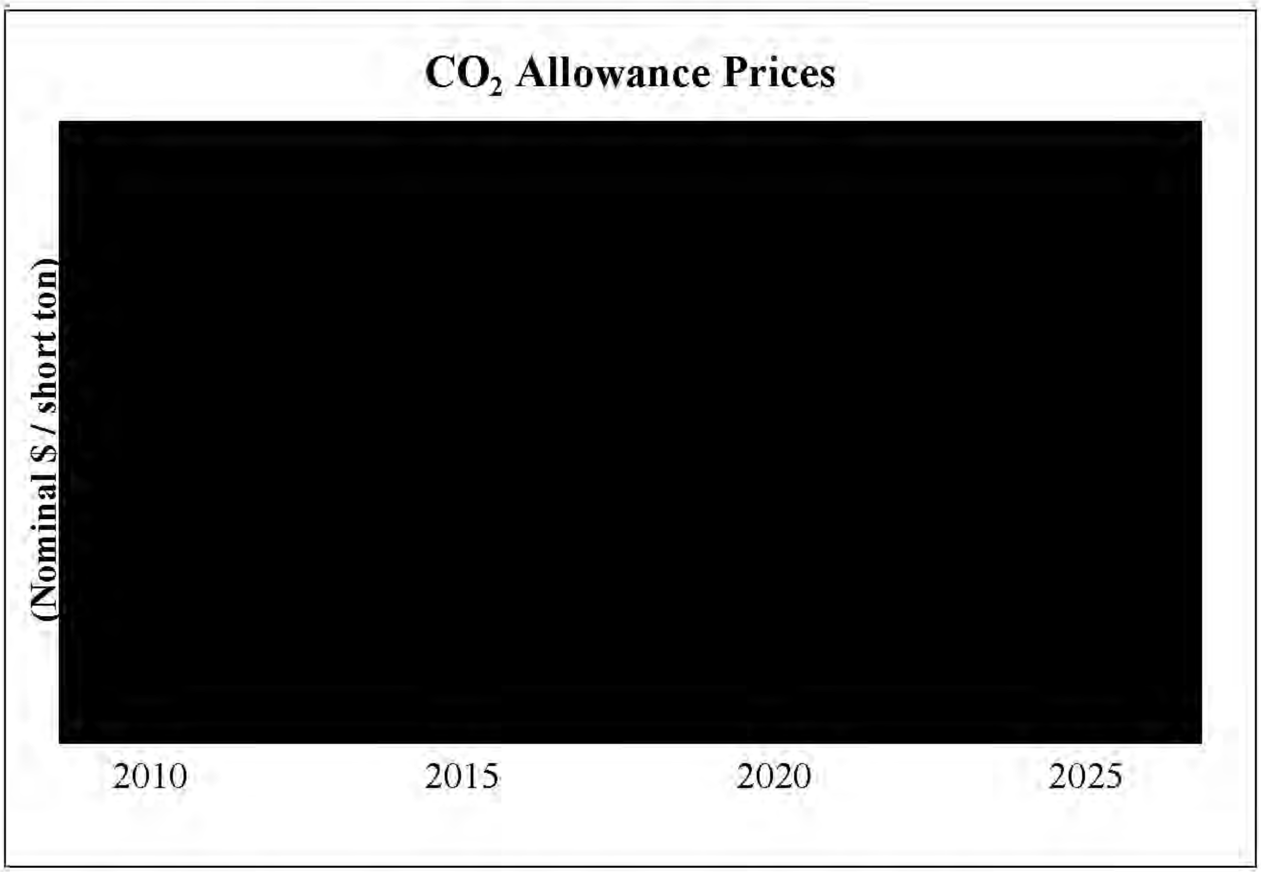

Figure 6: CO_2 Allowance Prices (Nominal $/Short Ton) for the CO_2 Policy Branches of Probability Tree, Excluding the Business-As-Usual Scenario.

The Mandates scenario (given by the blue line on the horizontal axis in Figure 6) envisioned another major greenhouse gas reduction policy outside of emission trading markets. In place of an explicit CO_2 price, a patchwork of prescriptive federal policies would effect reductions in CO_2 emissions. First, the scenario sets a national renewable portfolio standard (RPS) requiring 20% of U.S. electricity demand to be met by renewable generation technologies by 2020. As given in Figure 7, the national RPS becomes binding in 2010 at 7.5%, rises at 1.0% per year though 2015 and then at 1.5% per year through 2020, and then remains at 20% through the planning horizon. To accommodate regions with less renewable generating options, the scenario establishes a \$30/MWh ceiling on the price of national renewable energy credits (RECs). In addition, the Mandates scenario prohibits new coal builds without carbon sequestration capabilities after 2015.[1] Though such mandates might not have the same environmentalist fervor as market-based approaches, they could have a higher chance of political passage if cap-and-trade negotiations stall. How to equitably distribute free CO_2 allowances (and, in turn, alleviate the significant near-term costs) continues to encumber cap-and-trade policies aiming for significant reductions in CO_2 emissions. This inertia surrounding market-based approaches might then induce less comprehensive, but more politically feasible prescriptive regulations on the state and ultimately Federal level. As such, AmerenUE assigned a nonzero probability to the Mandates case.

[1] The scenario does not stipulate, however, that coal generators built prior to 2015 be shut down.

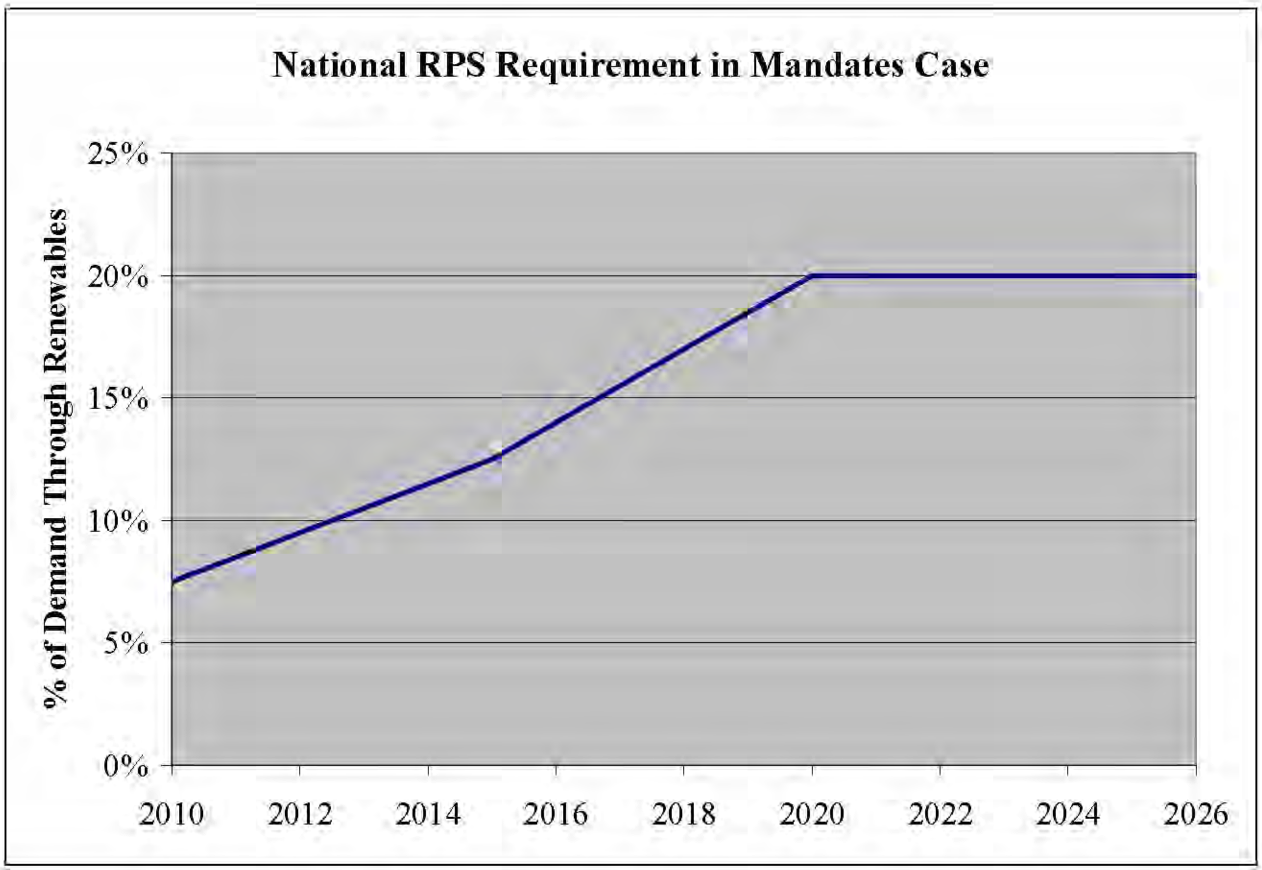

Figure 7: National RPS Modeled in the Mandates Case.

The last CO_2 policy branch in the probability tree is the business-as-usual, or BAU, scenario. This case represents the continuation of the present world, with no major greenhouse gas policy measures within the planning horizon and with base case assumptions for natural gas prices and load growth. Despite having a very small probability, the BAU case was still included in the probability tree because it represents an upper bound on the range of load growth projected in AmerenUE's service territory. All other things equal, both higher natural gas prices and more aggressive rates of energy efficiency improvement would reduce demand growth relative to BAU forecasts. Thus, modeling the BAU as a scenario and using its integrated projections of key IRP driver variables to probabilistically select alternative resource plans hedges against the risks of a capacity shortage, as explained in the response to section 4 CSR 240-22.030 (7).

4 CSR 240-22.040 (2)(B)3

For each mitigation level identified pursuant to paragraph (2)(B)2., the utility shall specify a subjective probability that represents utility decision-maker's judgment of the likelihood that additional laws or regulations requiring that level of mitigation will be imposed at some point within the planning horizon. The utility, based on these probabilities, shall calculate an expected mitigation level for each identified pollutant.

An integral component of a risk analysis of alternative resource plans is the assignment of subjective probabilities to each of the critical uncertainties. That is, the following uncertainties encompassed in the probability tree need to be stated as a probability distribution function (pdf):

1. Greenhouse gas (GHG) policy outcomes, especially in terms of CO_2 price levels;
2. Natural gas prices;
3. Load growth paths, especially in terms of breakthroughs in energy efficiency and distributed generation.

Having assigned a probability to each of the three forks in a tree branch, the likelihood of an integrated scenario (*i.e.*, of the endpoint in a tree branch) is simply the product of the probabilities of each fork. The elicitation process on climate policy futures conformed to the tenets of decision analysis laid out in the response to section 4 CSR 240-22.030 (7).

Two senior executives from AmerenUE were designated experts to assign subjective probabilities to each of the four CO_2 branches of the IRP probability tree: (1) Dan Cole, Senior Vice President, Administration; and (2) Joe Power, Vice President, Federal Legislation and Regulatory Affairs. CRA interviewed each expert separately, and both independently chose to structure their thinking by creating an "event tree." This "event tree" illustrates the different possible political developments that could affect both the direction and timing of GHG policy outcomes. Moreover, it is devised to provide insight into the likelihood of each CO_2 branch of the probability tree. In the case of a market-based approach to abating CO_2 emissions, the experts isolated their thought processes around cap-and-trade mechanisms, and the likelihood of a federal bill passing at various junctures in the IRP horizon. Figure 8 below offers the approximate configuration of the GHG experts' event trees.

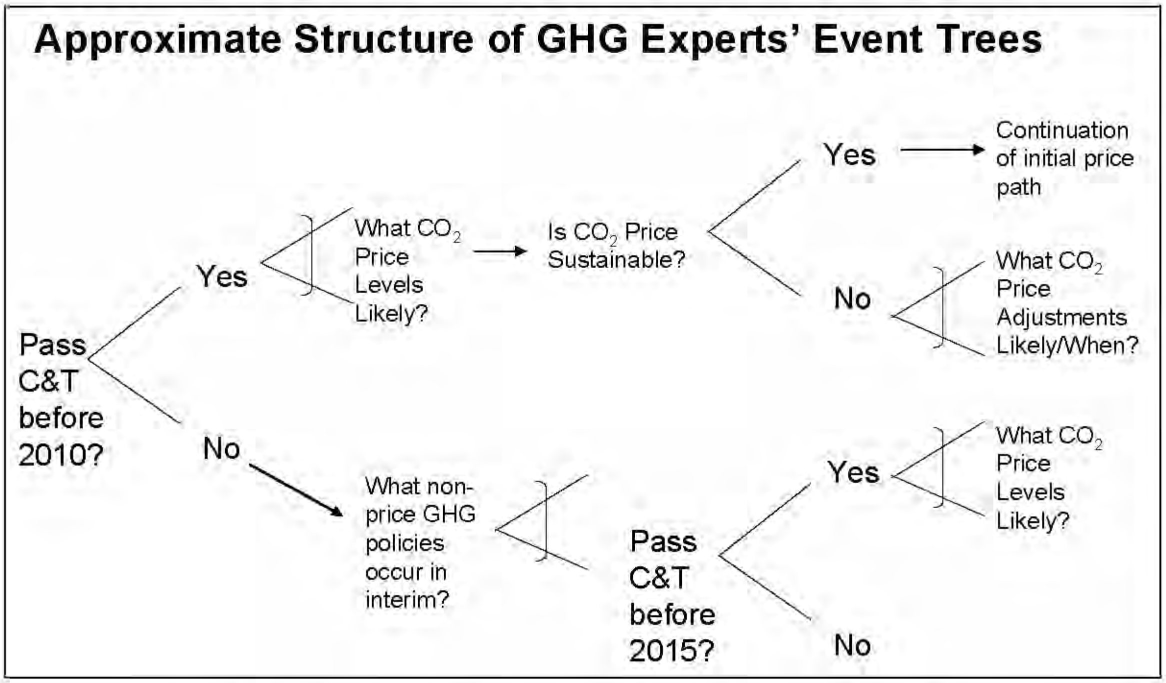

Figure 8: Approximate Structure of GHG Experts' Event Trees.

In order to grasp reasonable bounds for this political willingness to pay for CO_2 emissions, the experts discussed hypothetical economic impacts of a range of 2020 CO_2 prices, particularly [redacted] to [redacted] per short ton. Even at the lower end of this range, preliminary analysis revealed substantial reductions in national output from some of the largest energy-intensive sectors of the economy. The political traction of such negative economic impacts factored into the formulation of the event tree (and eventually of the CO_2 policy branches) that captured the full range of uncertainty without venturing into a highly improbable world view.

The construction of an event tree like that presented in Figure 8, in which the expert assigns a discrete probability to each temporal event, offers several key insights. One, it quantifies the chance of no CO_2 policy through 2026; that is, of the BAU branch. Two, it assesses each expert's expectation for a non-price GHG policy, which the probability tree embodies in the Mandates scenario. Three, it guides the formulation of a continuous CO_2 price distribution for each expert, given that a cap-and-trade bill becomes law at some point within the IRP horizon. Before plotting CO_2 prices across the duration of the horizon, CRA elicited the probability that some form of cap and trade would occur before 2026. Simultaneously, there was discussion devoted to the idea of a collection of mandates accumulating in the absence of binding cap-and-trade legislation, to the extent that formal cap and trade became politically unwarranted. The remaining slice of probability would be attributable to the continuation of the present no-significant-policy course.[2] The end results of this process are illustrated in Figure 9.

[2] Each expert approached the assignment of probabilities differently, such that the probability assigned to the BAU branch might have been the first step, as opposed to the last.

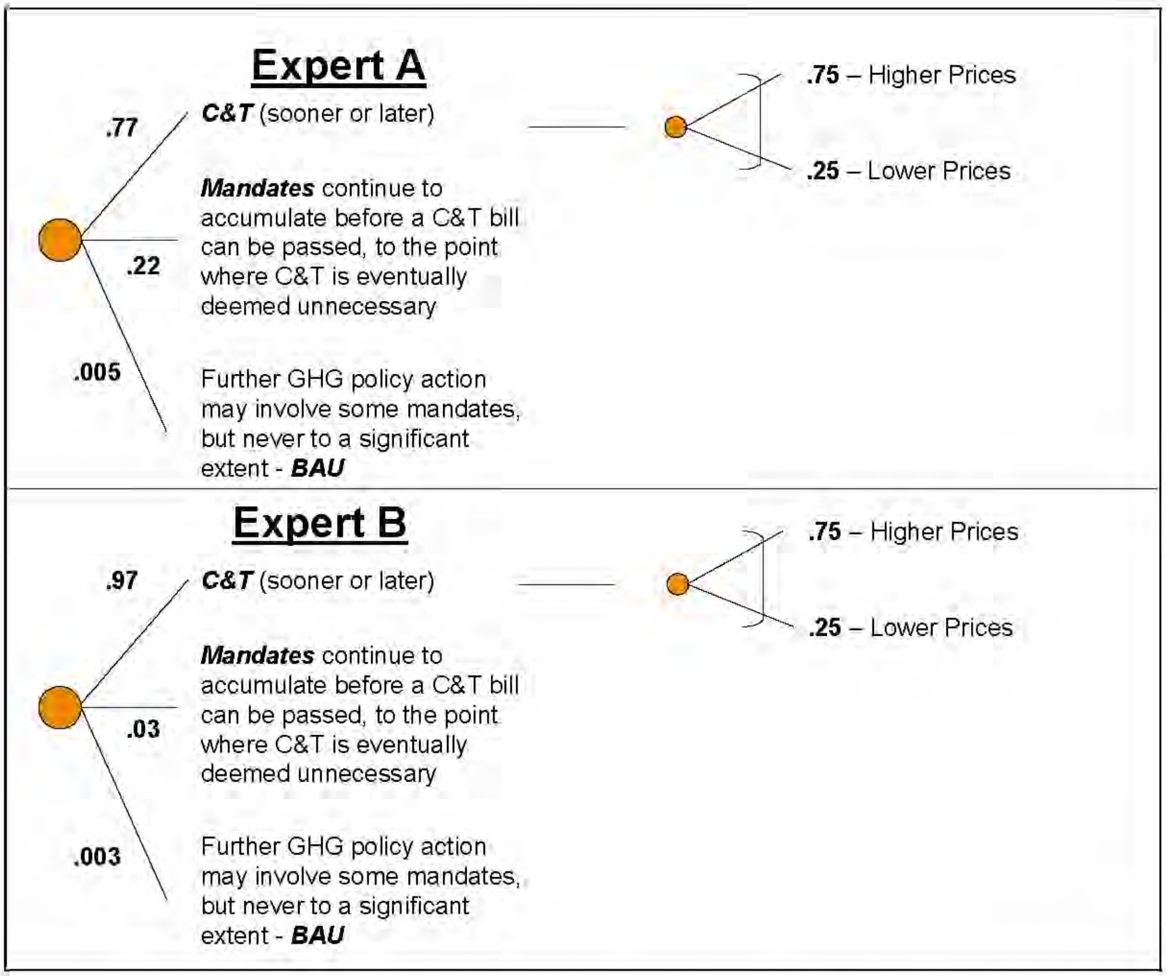

Figure 9: Assignment of Probabilities to Cap-and-Trade, Mandates, and BAU CO_2 Policy Branches.

The most significant disparity in opinion between the two experts was in the distribution of probability between the mandates-only and cap-and-trade policy branches. After the first round of the elicitation process, the experts were presented with this discrepancy and asked to think about a suitable consensus. Each agreed that splitting the difference in the probability, such that the cap-and-trade branches constituted a little less than 88% of the likelihood and the Mandates branch approximately 12%, was consistent with their views. The next step was to develop a range of plausible CO_2 prices and associated subjective probability distribution functions (pdfs), provided that cap-and-trade positively happens. After discussing reasonable CO_2 price bounds, each expert was guided into representing the range of CO_2 prices by two generic sets of "higher" and "lower" prices. Both believed that provided a "low" or "high" price trajectory was in place, there would be no drastic variations in growth rates. That is, as given in Figure 8, each set of CO_2 prices, once implemented, would be sustainable through the planning horizon. Despite some discrepancies in the actual price levels, each expert independently assigned 75% probability to the "higher" case and 25 % probability to the "lower" case.

With the event tree structure in Figure 8 governing the elicitation process, each expert developed a "high" and "low" CO_2 price every three years from 2012 through 2030. Figure 10 presents the results of this phase, in which cap-and-trade was treated as a given.

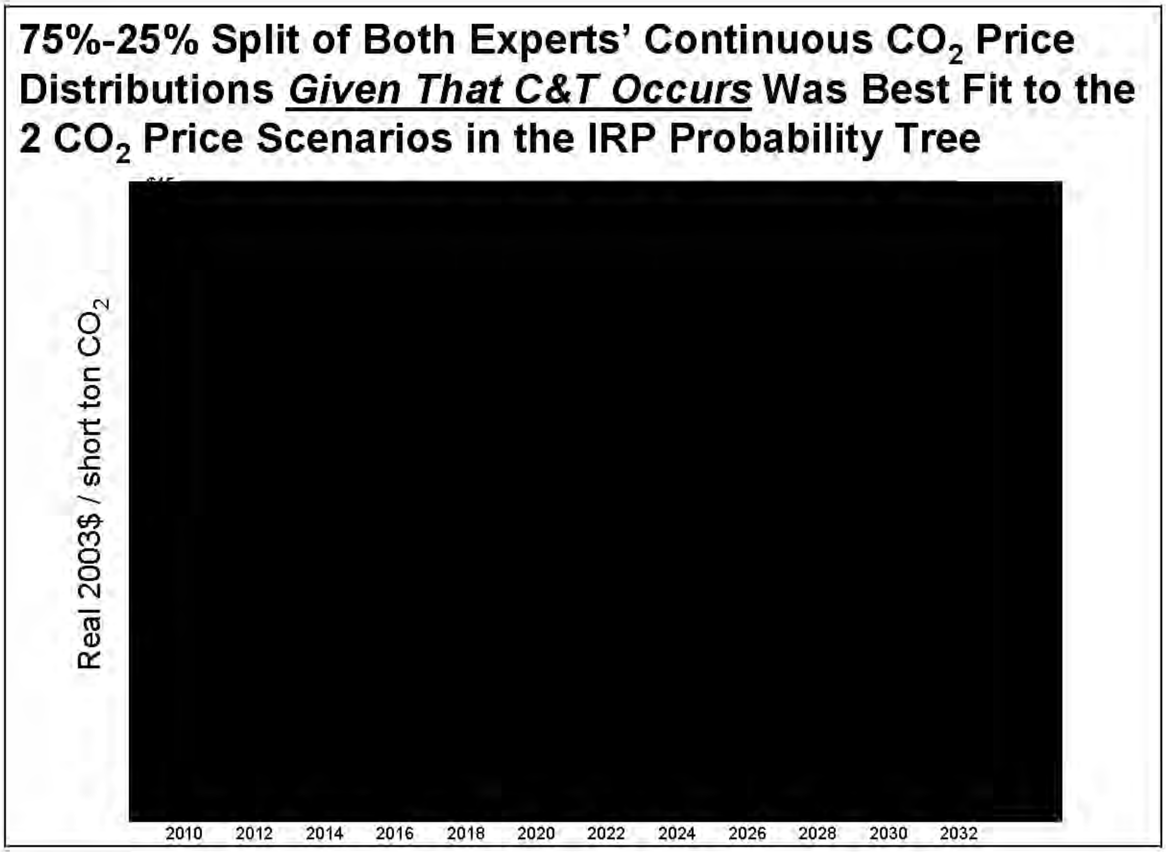

Figure 10: Experts' "Higher" and "Lower" CO_2 Price Paths alongside Cap and Trade Price Paths in the Probability Tree.

The "higher" and "lower" price paths elicited from each expert were very closely aligned not only with one another, but, more importantly, with the "High" and "Moderate" CO_2 policy branches in the probability tree. The final probability assignments to each of the four GHG branches in the probability tree are given below in Figure 11. Note that the probability assigned to the high CO_2 price case equals the product of the probability of cap-and-trade eventuating within the IRP horizon (88%) and that of higher CO_2 prices given that precondition (75%). For the moderate CO_2 policy case, the conditional probability in the above equation is 25%.

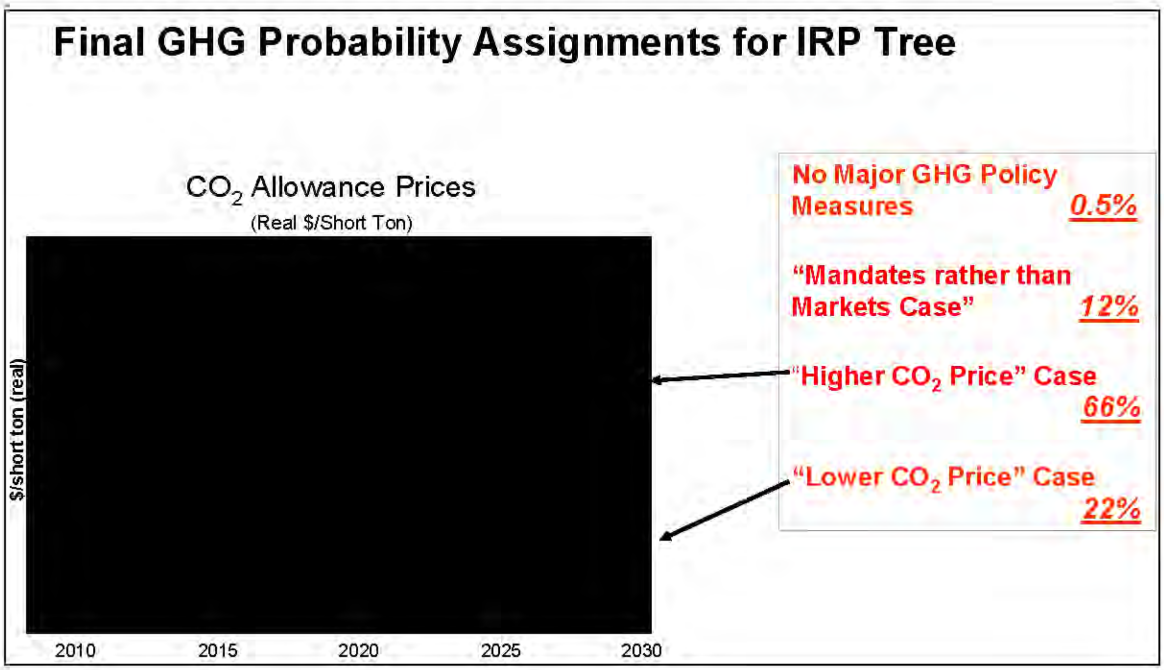

Figure 11: Final CO_2 Policy Probability Assignments for the Probability Tree.

4 CSR 240-22.040 (2)(B)4

The probable environmental cost for a supply-side resource shall be estimated as the joint cost of simultaneously achieving the expected level of mitigation for all identified pollutants emitted by the resource. The estimated mitigation costs for an environmental pollutant may include or may be entirely comprised of a tax or surcharge imposed on emissions of that pollutant.

Table 60 below summarizes the probable environmental costs related to SO_2, NO_X, Hg, and CO_2 emissions for generic new unit types in the MRN-NEEM model. For coal-based technologies, namely advanced coal, integrated gasification combined cycle (IGCC), and integrated gasification combined cycle with carbon capture and sequestration (IGCC with CCS), SO_2 and Hg emissions are a function of both the generation/retrofit technology and the type of coal being burned. CRA's North American Electricity & Environment Model, or NEEM, provides exceptional detail of the U.S. coal sector, with coal supply curves representing 21 distinct coal supply regions and coal types. These coal supply regions are linked to the generation units by a coal transportation matrix with unit-specific transportation costs. Naturally, each variety of coal differs in the content of SO_2 and Hg per unit of heat input, and the lower and upper bounds for emissions rates given in Table reflect this range (note that the Hg emissions rate is given in lb/TWh, whereas all other rates are in lb/MWh). NO_X and CO_2 emissions rates, on the other hand, are assumed to be invariant to the type of coal being used, and are solely determined by generation technology. NEEM assumes a CO_2 emissions rate of 207.9 lb/million British thermal units (MMBtu) for coal-based capacity, with CCS technology achieving a 90% reduction in CO_2 emissions. The CO_2 emissions for gas-fired combined cycle (CC) and combustion turbine (CT) units are assumed to be 116.7 lb/MMBtu. NO_X emissions rates range from 0.02 lb/MMBtu (CC) to 0.08 lb/MMBtu (CT) among emitting new unit types. These rates, in terms of energy input, are then multiplied by the fully loaded heat rate to produce the emissions rates of Table , given in terms of the electricity produced.

To clarify, consider the CO_2 emissions rate given below for IGCC with CCS capacity. NEEM assumes that this technology captures and sequesters 90% of the 207.9 lb of CO_2 emitted per unit of energy input. Thus, the rate of CO_2 released into the atmosphere from an IGCC with CCS generator is 20.79 lb/MMBtu. NEEM assumes a heat rate of 9.713 MMBtu/MWh for this capacity type.[3] As a result, the emissions rate for IGCC with CCS units is equal to the product of 20.79 lb/MMBtu and 9.713 MMBtu/MWh, equal to 202 lb/MWh.

Table 60: Estimated Mitigation Costs for Generic New Capacity.

	*Emissions Rate (lb / MWh or TWh)**				*Mitigation Costs ($ / MWh)*			
New Unit Type	**SO_2**	**NO_X**	**Hg**	**CO_2**	**SO_2**	**NO_X**	**Hg**	**CO_2**
Coal	0.12 - 0.92	0.53	1.61 - 9.23	1,839	*Mitigation Cost = C_t * Emissions Rate, where C_t = Allowance Price per lb*			
IGCC	0.11 - 0.86	0.58	1.52 - 8.67	1,727				
IGCC with CCS	0.13 - 1.01	0.68	1.77 - 10.13	202				
CC	-	0.14	-	817				
CT	-	0.87	-	1,265				
Nuclear	-	-	-	-				
Renewables	-	-	-	-				

The cost of mitigating the emissions of a particular pollutant is dependent upon the emissions rate and the market price of an emissions allowance, C_t. In the moderate and high CO_2 price scenarios, the market price of CO_2 is represented by a simple CO_2 price, as exhibited in figure 6. Recall that there is no explicit price on CO_2 emissions in the Mandates and BAU branches of the probability tree. For the three pollutants (SO_2, NO_X, and Hg), however, NEEM estimates allowance prices consistent with all existing environmental regulations in fully-functioning allowance price markets. These are:

- Title IV/Clean Air Interstate Rule ("CAIR") for SO_2 – Title IV melds into the CAIR SO_2 program beginning in 2010 when units in the CAIR region (including units in Missouri) are required to submit two allowances for every ton emitted. This increases to 2.86 allowances per ton emitted in 2015 and beyond;

[3] For purposes of comparison, NEEM assumes a heat rate of 10.4 MMBtu/MWh for new nuclear capacity, 8.844 MMBtu/MWh for new coal capacity, 8.309 MMBtu/MWh for IGCC capacity, 7.0 MMBtu/MWh for CC capacity, and 10.842 MMBtu/MWh for CT capacity.

- SIP Call/CAIR Ozone Season NO_X – the SIP Call program for ozone season NO_X compliance is modeled in Missouri through 2008, after which this program is phased out in place of the CAIR Ozone Season NO_X program;

- CAIR Annual NO_X – the CAIR Annual NO_X program begins in 2009 for much of the Eastern United States including Missouri, with a second, tighter cap in 2015;

- Clean Air Mercury Rule ("CAMR") – the final CAMR rule begins in 2010 and applies to all generating units in all states, with a second, tighter cap in 2018.

NEEM dynamically calculates allowance prices for NO_X, SO_2, and Hg emissions subject to each of the above constraints. In general, if an emissions cap is binding at any point during the model horizon, the allowance price is equal to the marginal cost of abating one more pound or ton of pollutant. NEEM allows for banking, so emissions in a given year do not necessarily match the prescribed annual limits of the program, as given below in Table 61. The degree to which the prescribed caps are binding (*i.e.*, the level of emissions), combined with optimal banking choices, sets the equilibrium allowance price. NEEM determines unit-level emissions for SO_2, NO_X and Hg based on each modeled unit's fuel choices, existing equipment, retrofit choices, and dispatch, the details of which are described below.

Table 61: SO_2, NO_X, and Hg Emissions Limits.

	SO_2	NO_X			Hg
	Title IV/CAIR	**SIP Call**	**CAIR Ozone**	**CAIR Annual**	**CAMR**
Year	Million Tons	Thousand Tons	Thousand Tons	Million Tons	Tons
2008	9.44	528	-	-	-
2009	9.44	-	568	1.722	-
2010	8.95	-	568	1.722	38
2015	8.95	-	485	1.268	38
2018	8.95	-	485	1.268	15
2020	8.95	-	485	1.268	15
2030	8.95	-	485	1.268	15

SO_2 emissions in NEEM are dynamically calculated over time in response to a number of endogenous factors. Initial data that is used to calculate SO_2 emissions includes the quantity and characteristics of the existing coal fleet, particularly the capacity, existing equipment, and coal types that can be burned at each unit. NEEM models existing Federal SO_2 legislation and rules including Title IV and the Clear Air Interstate Rule (CAIR). These provide a cap on the level of SO_2 emissions. The model also includes an estimate of the existing bank of SO_2 allowances entering 2007 (approximately 6 million tons) and allows for additional banking or withdrawals from the bank in order to comply with the cap in the most cost efficient manner possible.

The emissions from existing coal units will change over time in response to the SO_2 allowance price projected by NEEM and the SO_2 reduction options available to each unit. Units can reduce their SO_2 emissions in a number of ways. First, units that do not have either a wet or dry flue gas desulfurization (FGD) retrofit may add one. The cost of these retrofits is a function of the size of the unit and the cost parameters included in Table 62.[4] A unit will add an FGD if the cost of installing the FGD, as measured in

[4] Based upon the testimony of J.E. Cichanowicz to the Illinois Pollution Control Board, Notice of Filing in the Matter of: Proposed New 35 Ill. Adm. Code 225 Control of Emissions From Large Combustion Sources, Case No. R2006-025, submitted 7/28/2006, Appendix B and upon follow-up discussions. The dry FGD option includes the capital costs of a fabric filter, but there is another dry FGD option available in NEEM for units that already have activated carbon injection with a fabric filter (ACI/FF) installed. As for the variable operating and maintenance (O&M) costs for the wet FGD technology, AmerenUE assumes medium coal sulfur content.

dollars per ton of SO_2 removed, is less than the cost of purchasing allowances for that unit over the useful life of the retrofit.[5]

Table 62: Retrofit Costs and Characteristics.

Retrofit	Reference Size (MW)	Capital Cost ($/kW)	Fixed O&M ($/kW-Yr)	Scaling Exponent	Variable O&M ($/MWh)	% Removal
Wet FGD	500	$380.83	$8.17	-	$2.20	98%
Dry FGD	500	$304.18	$6.69	-	$1.05	90%
SCR	243	$200.00	$0.72	0.270	$0.66	90%
SNCR	150	$20.04	$0.30	0.629	$0.96	35%
ACI	250	$36.58	$1.83	0.333	$0.77	60% - 75%
ACI/FF	600	$115.34	$5.77	0.333	$0.32	90%
HACI	250	$36.58	$1.83	0.333	$1.13	50% - 90%

A second option to reduce SO_2 emissions is to change coal types. As shown in Table 63, each coal has different SO_2 contents. If a coal can be delivered to the unit then it can switch to burning that coal. For units that do not currently burn Powder River Basin (PRB) coal, a capital cost would be incurred to account for the plant being able to burn PRB coals. Lastly, a unit can reduce its SO_2 emissions by cutting back on generation. If the unit does not have other options, its SO_2 emissions costs may push it higher up the dispatch curve and therefore cause it to generate less. In addition to existing coal units, new coal units also produce SO_2 emissions. All new coal units, however, are assumed to include a wet FGD and therefore have an SO_2 emission rate that reflects 98% removal of inlet SO_2.

[5] Under CAIR, units in the CAIR region would need to purchase two allowances for each ton emitted from 2010 through 2014 and 2.86 allowances per ton emitted from 2015 onwards. Thus, if a unit were located in the CAIR region and the allowance price in 2010 were $500, the unit would add an FGD if the cost per ton removed were less than $1,000 per ton ($500 allowance price multiplied by two to account for the need for two allowances per ton emitted).

Table 63: Coal Characteristics.

Coal Type	Rank	SO_2 (lbs/MMBtu)	Hg (lbs/TBtu)	Heat Content (Btu/lb)
Northern Appalachia - High Btu, Low Sulfur	Bituminous	2.47	12.31	12,862
Northern Appalachia - High Btu, High Sulfur	Bituminous	3.95	12.54	12,900
Northern Appalachia - Low Btu, Low Sulfur	Bituminous	1.72	15.98	12,097
Northern Appalachia - Low Btu, High Sulfur	Bituminous	3.42	20.87	11,782
Central Appalachia, Compliance	Bituminous	1.12	5.87	12,731
Central Appalachia, Non-Compliance - High Btu	Bituminous	1.5	8.24	12,637
Central Appalachia, Non-Compliance - Low Btu	Bituminous	1.8	9.2	12,030
Southern Appalachia	Bituminous	1.97	8.73	12,185
Illinois Basin, High Sulfur	Bituminous	5.2	6.44	11,395
Illinois Basin, Medium Sulfur	Bituminous	2.8	6.44	11,395
Illinois Basin, Low Sulfur	Bituminous	1.7	6.44	11,395
Central Basin	Bituminous	4.82	12.72	12,077
Lignite	Lignite	2.62	10.8	6,743
Powder River Basin, Montana	Sub-bituminous	1.19	5.17	9,043
Powder River Basin, Northern Wyoming	Sub-bituminous	0.89	7.08	8,380
Powder River Basin, Central Wyoming	Sub-bituminous	0.75	5.42	8,562
Powder River Basin, Southern Wyoming	Sub-bituminous	0.65	5.76	8,854
Rocky Mountain, Colorado	Western Bit.	0.93	3.65	11,466
Rocky Mountain, Utah	Western Bit.	1.04	4.14	11,554
Four Corners	Bituminous	1.44	4.2	9,666
Import	Bituminous	0.98	5.52	12,000

NO_X emissions in NEEM are also dynamically calculated over time in response to a number of endogenous factors. Unlike SO_2, NEEM includes initial NO_X emission rates for coal-, natural gas-, and oil-fired plants. This information is based on third quarter 2005 NO_X rates reported as part of the EPA's Continuous Emissions Monitoring System (CEMS). Since the third quarter is part of the summer ozone season when post-combustion controls are most likely to be operated, these third quarter emission rates are more informed estimates. As previously described, all emitting units are subject to the caps prescribed by the SIP Call, CAIR NO_X Ozone Season, and CAIR NO_X Annual programs.

As for SO_2, there are multiple options for reducing NO_X emissions on existing units. Two retrofits are available to coal units.[6] These units will install either Selective Catalytic Reduction (SCR) or Selective Non-Catalytic Reduction (SNCR) if the cost per ton of NO_X removed is less than the NO_X allowance price that will be faced by the unit.

[6] Retrofits are not provided as an option for natural gas- or oil-fired units because they would be more expensive on a dollar per ton removed basis than for coal units.

The costs and characteristics of SCR and SNCR are included in Table 62.[7] The other means of reducing NO_X emissions from existing units is to reduce the level of generation from those units. New units, in contrast, are assumed to have controls in place necessary to meet New Source Performance Standards (NSPS). As such, new coal units have a NO_X emission rate of 0.06 lbs/MMBtu, new combined cycle units have a NO_X emission rate of 0.02 lbs/MMBtu, and new combustion turbines have a NO_X emission rate of 0.08 lbs/MMBtu.

Similar to SO_2 emissions, Hg emissions are only from coal-fired units. Hg emissions for any coal unit are a function of the coal burned and the equipment in place on the unit. While there are Hg-specific retrofits, Hg can also be removed as a co-benefit from some non-Hg controls such as FGDs and SCRs. The Hg co-benefits given in Table 64 were provided to CRA by the Electric Power Research Institute (EPRI), and used as part of comments filed in response to the proposed Clear Air Mercury Rule (CAMR).[8]

[7] Based upon the testimony of J.E. Cichanowicz to the Illinois Pollution Control Board, Notice of Filing in the Matter of: Proposed New 35 Ill. Adm. Code 225 Control of Emissions From Large Combustion Sources, Case No. R2006-025, submitted 7/28/2006, Appendix B and upon follow-up discussions. SCR capital costs represent CRA best estimates, informed by the above Cichanowicz testimony and by 2006 EPA Integrated Planning Model (IPM) base case assumptions, available at http://epa.gov/airmarkets/progsregs/epa-ipm/index.html. All other information pertaining to SCR and SNCR costs and characteristics in Table are derived from the 2006 EPA IPM base case assumptions.

[8] This EPRI report, entitled "EPRI Comments on EPA Proposed Emission Standards/Proposed Standards of Performance, Electric Utility Steam Generating Units: Mercury Emissions" is available at http://www.epa.gov/mercury/pdfs/OAR-2002-0056-2578.pdf.

Table 64: Mercury (Hg) Co-Benefits.

Equipment in Place			% Removal of Inlet Hg		
PM Control	**SO_2 Control**	**NO_X Control**	**Bituminous**	**PRB**	**Lignite**
Fabric Filter	Dry FGD	No SCR	85	25	10
		SCR	90	25	10
	Wet FGD	No SCR	85	75	40
		SCR	90	75	40
	No FGD	No SCR	75	65	10
		SCR	75	65	10
Cold-Side ESP	Dry FGD	No SCR	50	15	10
		SCR	85	15	10
	Wet FGD	No SCR	60	35	35
		SCR	85	35	35
	No FGD	No SCR	35	20	10
		SCR	35	20	10
Hot-Side ESP	Dry FGD	No SCR	0	0	0
		SCR	0	0	0
	Wet FGD	No SCR	55	30	30
		SCR	85	30	30
	No FGD	No SCR	20	0	0
		SCR	20	0	0
Venturi Scrubber	Dry FGD	No SCR	25	15	15
		SCR	60	15	15
	Wet FGD	No SCR	25	15	15
		SCR	60	15	15
	No FGD	No SCR	20	5	5
		SCR	20	5	5

Table lists the three mercury control options available to coal-fired units in NEEM in order to comply with the emissions limits stipulated by the CAMR rule. The Activated Carbon Injection (ACI) technology can only be operated in conjunction with bituminous coal use, and represents a less capital-intensive option for larger units that can rely on existing particulate matter (PM) controls for mercury co-benefits. If the unit already has a fabric filter (FF), then ACI alone was an available retrofit. On the other hand, if the unit did not have a fabric filter, then the ACI option available to it, ACI/FF, was naturally more costly because it also included the installation of a fabric filter.[9] The

[9] Based on the testimony of J.E. Cichanowicz to the Illinois Pollution Control Board, Notice of Filing in the Matter of: Proposed New 35 Ill. Adm. Code 225 Control of Emissions From Large Combustion Sources, Case No. R2006-025, submitted 7/28/2006, Appendix B and upon follow-up discussions. The reference size and scaling exponent given for ACI are for the component of capital and FOM costs

last mercury control retrofit available is halogenated activated carbon injection (HACI), which is designed for use with sub-bituminous coals and incurs greater variable O&M than ACI due primarily to increased sorbent costs.

With perfect foresight through the end of the modeling horizon, NEEM then chooses generation patterns, fuel choices and consumption levels, and potential retrofit installations in a manner that minimizes the net present value of total system costs while meeting all reserve margin requirements and complying with all environmental regulations. Allowing for the banking (and subsequent withdrawal) of allowances that could result if permit prices rise faster than the 5% discount rate, NEEM charts an optimal allowance price path through the model horizon. Again, the resulting allowance price represents the marginal cost of abating one more pound or ton of the pollutant; that is, C_t, from Table 60. The following charts in Figure 12, Figure 13, and Figure 14 illustrate SO_2, NO_X, and Hg prices, respectively, for each of the nine branches in the final probability tree.[10] In the case of NO_X allowance prices, Figure 13 presents prices formulated under the SIP Call cap for the years prior to 2010, and then prices under the tighter CAIR NO_X Annual cap in all subsequent years. CO_2 permit prices in each of the scenarios are given in figure 6. In addition, 4 CSR 240-22.040 Appendix G lists the SO_2, NO_X, and Hg retrofits installed on AmerenUE coal plants in each of the nine scenarios.

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attributable to the upgrade of the electrostatic precipitator's (ESP) specific collecting area (SCA) to accommodate Hg removal, equal to $35/kW (in 2005 dollars) for a 250 MW unit. Capital costs also include the construction of a sorbent tower and modifications to the flue gas stream mechanisms, together equal to $2/kW (in 2005 dollars) for a 400 MW reference size (and with a power scaling factor of 0.9). Fixed operating and maintenance costs are assumed to be 5% of capital expenditures. ACI variable operating and maintenance costs are based upon sorbent costs of $0.50/lb, a sorbent injection rate of 4 lb/Mmacf, and disposal costs of $28/ton (all in 2005 dollars), as well as considerations of ash disposal costs. ACI/FF variable operating and maintenance costs are based upon a lower sorbent injection rate of 1.5 lb/Mmacf and a greater disposal cost of $1,200/ton (in 2005 dollars). The Hg removal percentages are dependent upon both the size of the generating unit and of the SCA of the ESP.

[10] See Table B - 3, Table B - 4, and Table B - 5 in 4 CSR 240-22.040 Appendix F for data Tables of SO2, NOX, and Hg allowance prices, respectively.

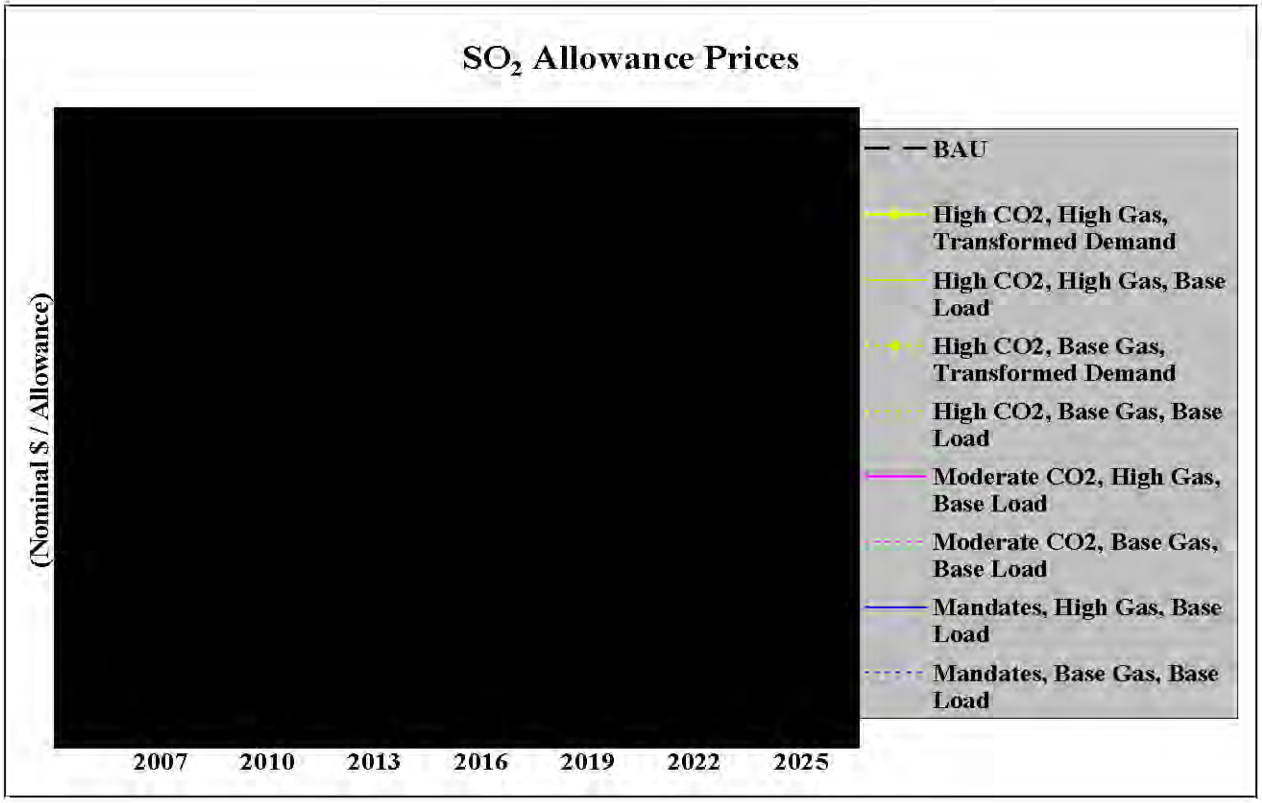


Figure 12: SO_2 Allowance Prices (Nominal $/Allowance).

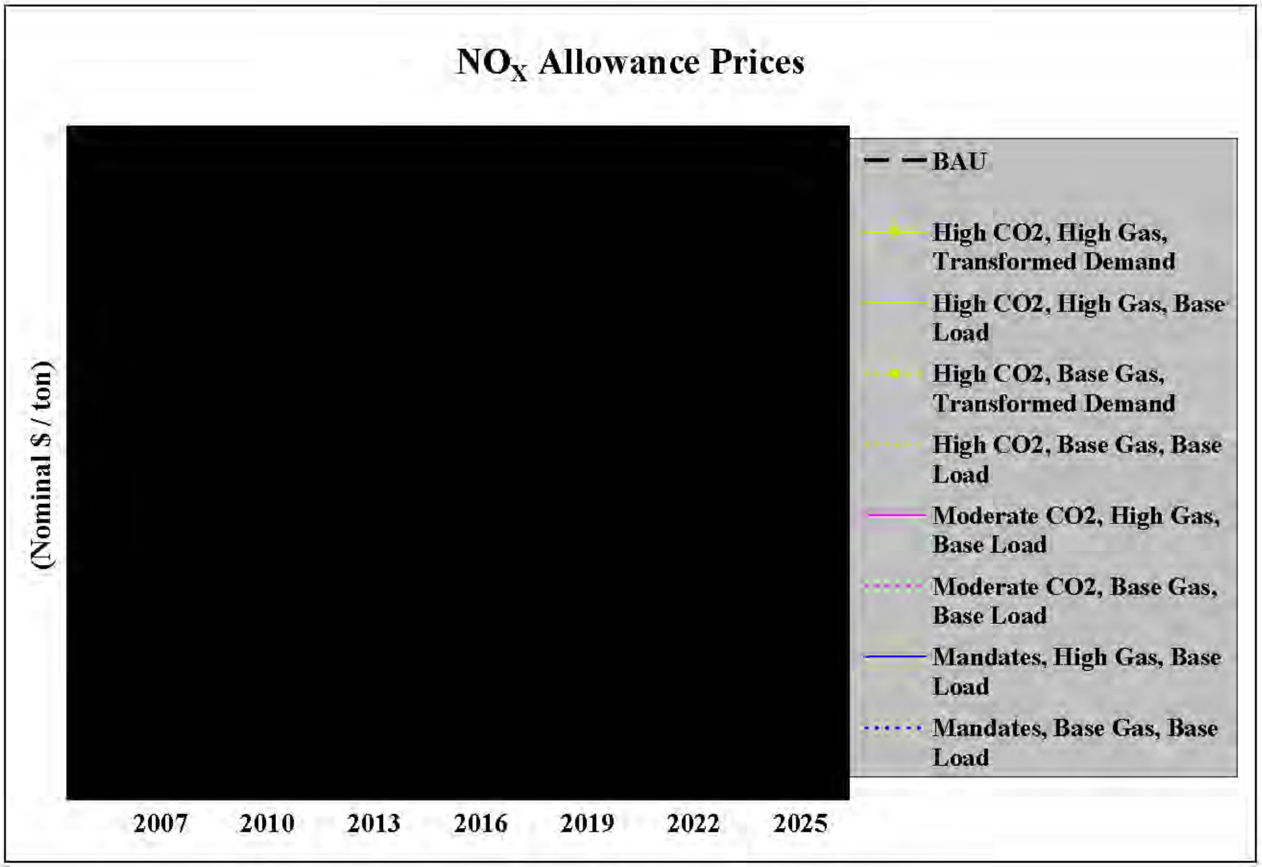


Figure 13: NO_X Allowance Prices (Nominal $/Ton).

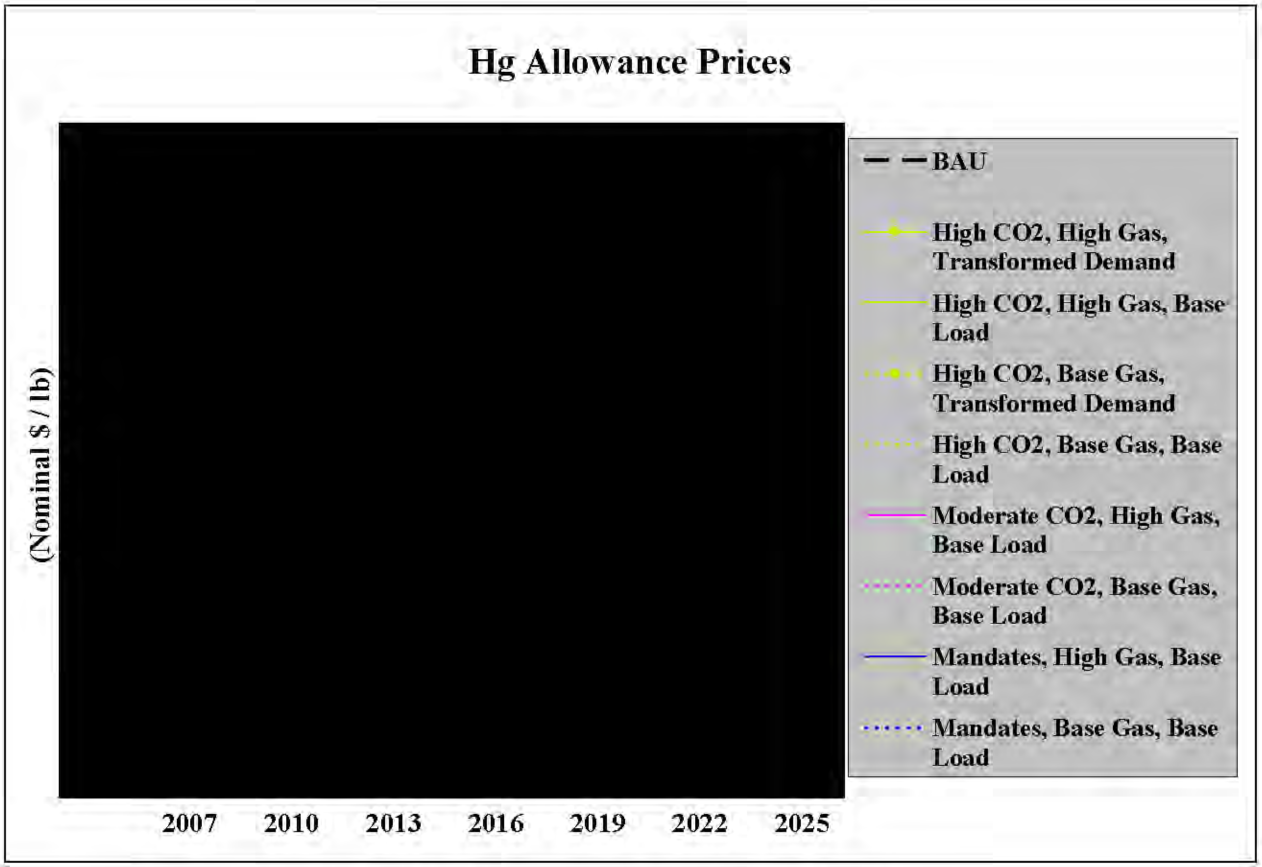


Figure 14: Hg Allowance Prices (Nominal $/lb).

4 CSR 240-22.040 (2)(C)

The utility shall rank all supply-side resource options identified pursuant to section (1) in terms of both of the following cost estimates: utility costs and utility costs plus probable environmental costs. The utility shall indicate which supply-side options are considered to be candidate resource options for purposes of developing the alternative resource plans required by 4 CSR 240-22.060(3). The utility shall also indicate which options are eliminated from further consideration on the basis of the screening analysis and shall explain the reasons for their elimination.

Fossil Fuel Resources

Each technology in the screening was scored according to criteria defined in Table 58. Scoring was applied as objectively as possible to ensure that technologies were evaluated on a consistent basis. The results of the scoring are shown in the Scoring Table of 4 CSR 240-22.040 Appendix D.

A graphical summary of the scoring results is shown on Figure 15. Scoring results for technologies with CO_2 mitigation, carbon capture and compression, are provided in a separate figure. Figure 16 graphically displays scoring results for technologies with CO_2 mitigation.

From these scorings, the resource options were narrowed to a short list of candidate resource options that best met the scoring criteria. These options include the following:

- Supercritical PC.
- IGCC.
- Combined Cycle Combustion Turbine - 2x1 7FB.
- Simple Cycle Combustion Turbine - Aeroderivative - LMS 100.
- Simple Cycle Combustion Turbine - Frame - 7FA.

These technologies should be carried forward to integration for modeling purposes. Modified cases for supercritical PC and IGCC are also carried forward.

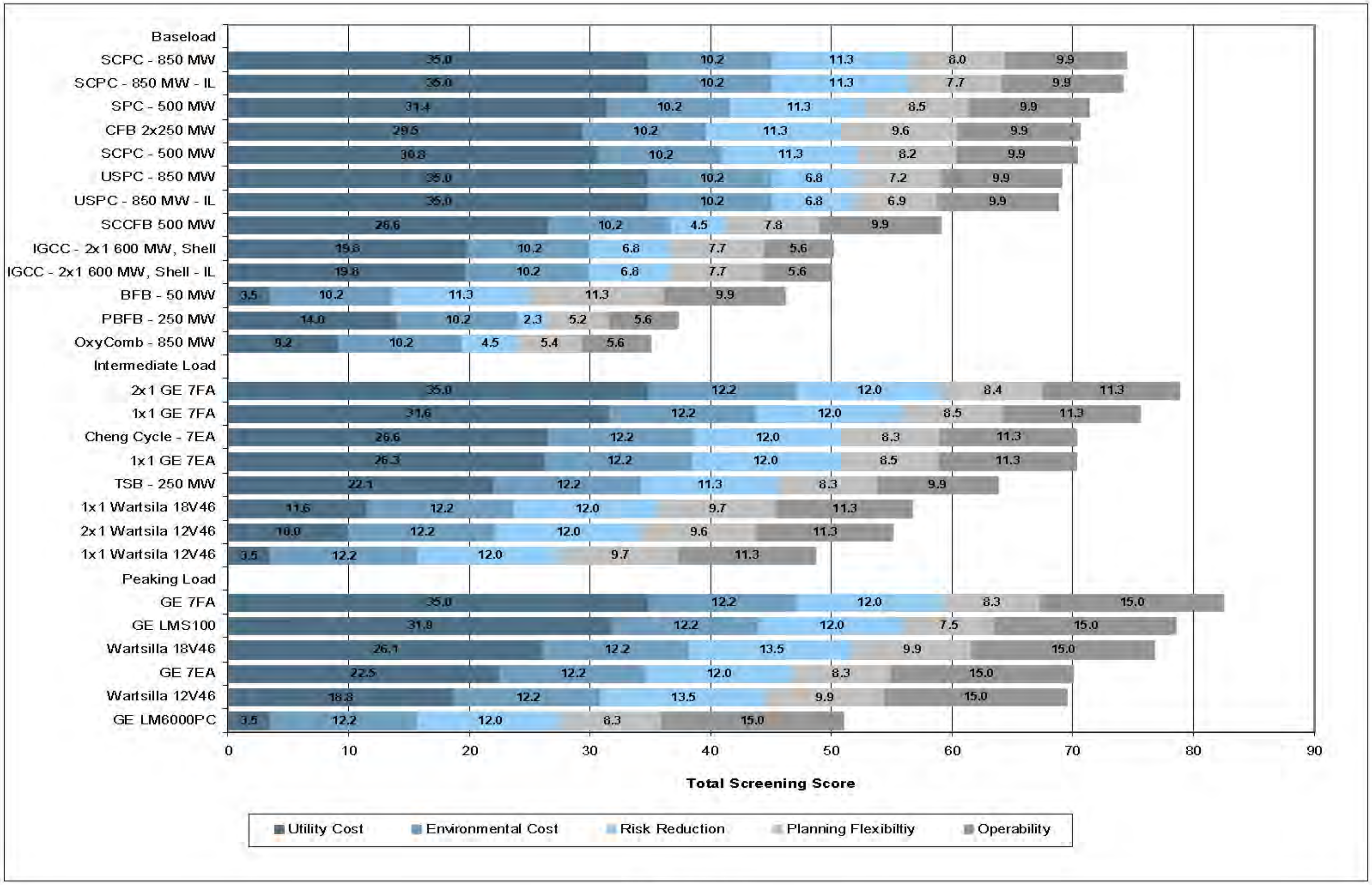


Figure 15
Summary of Scoring Results

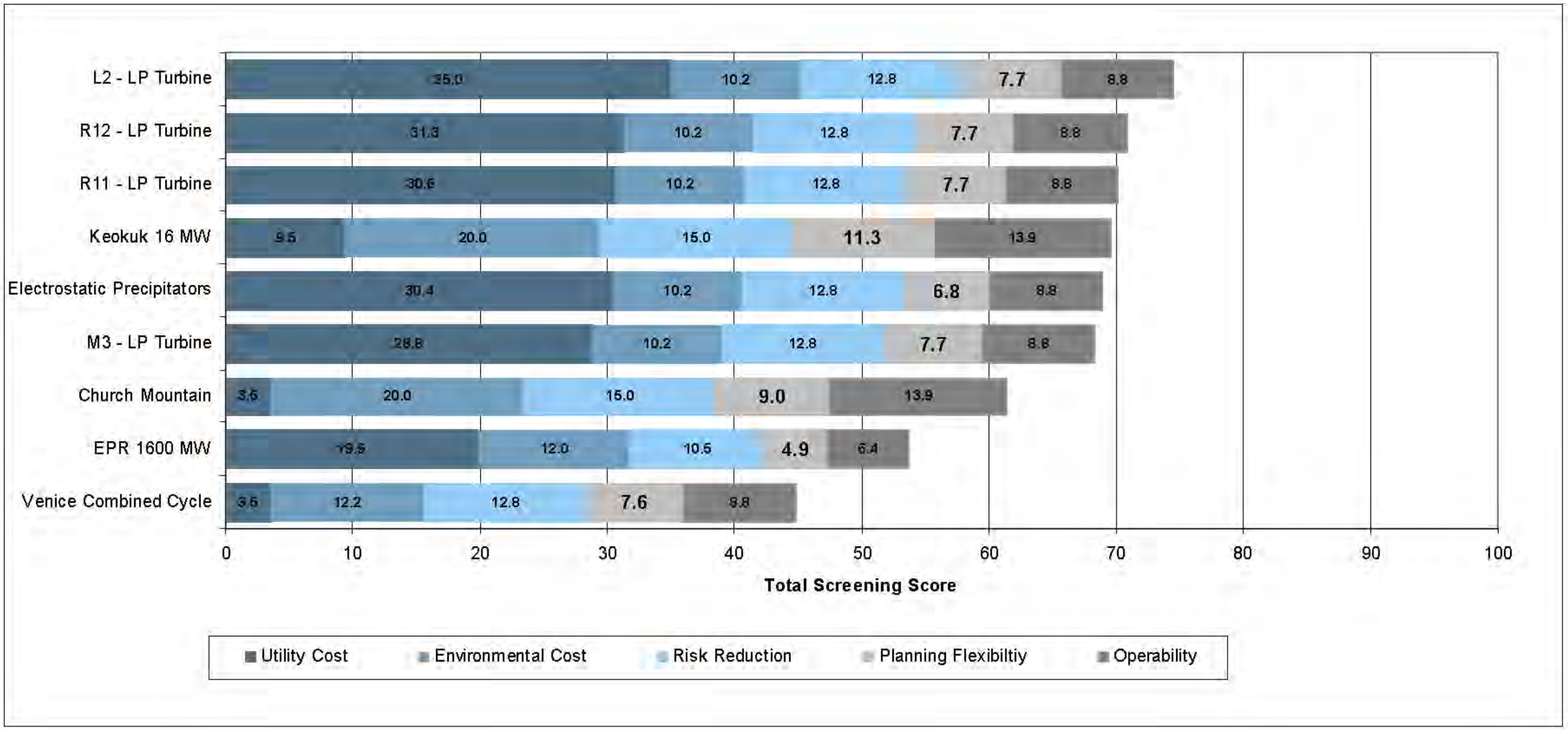


Figure 15
Summary of Scoring Results

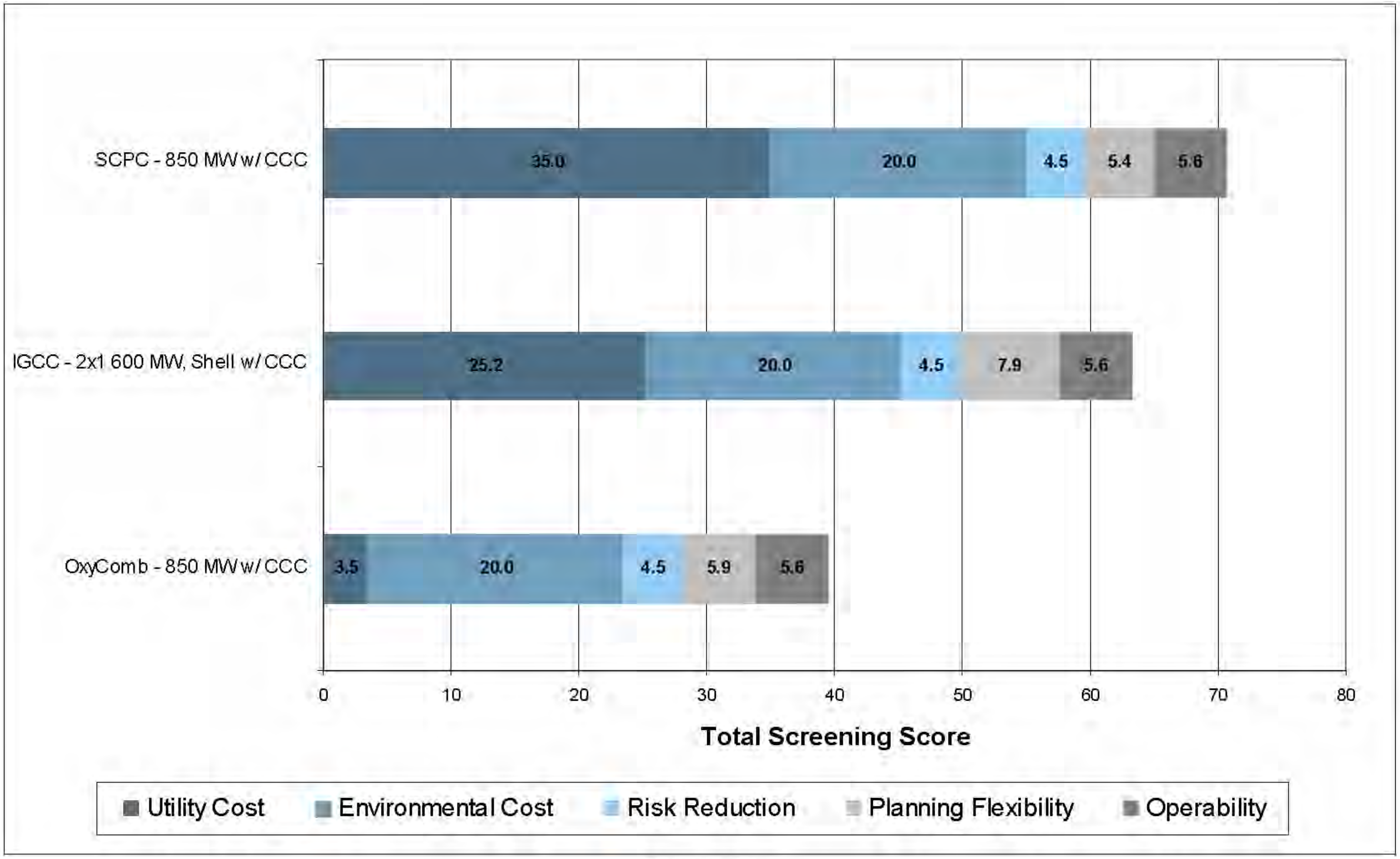


Figure 16
Summary of CO_2 Mitigation Scoring Results

Renewable and Energy Storage Resources

Each technology in the screening was scored according to criteria defined in Table 58. Scoring was applied as objectively as possible to ensure that technologies were evaluated on a consistent basis. The results of the scoring are shown in 4 CSR 240-22.040 Appendix D.

A graphical summary of the scoring results is shown on Figure 17.

From these scorings, the technology resource options were narrowed to a short list of candidate resource options that best met the scoring criteria. These candidate resource options include the following:

- Biomass Combustion – Standalone.
- Biomass Combustion – Cofiring.
- LFG – Reciprocating Engine.
- LFG – Combustion Turbine.
- Hydroelectric – Run of River.
- Wind.

These technologies should be carried forward to integration for modeling purposes.

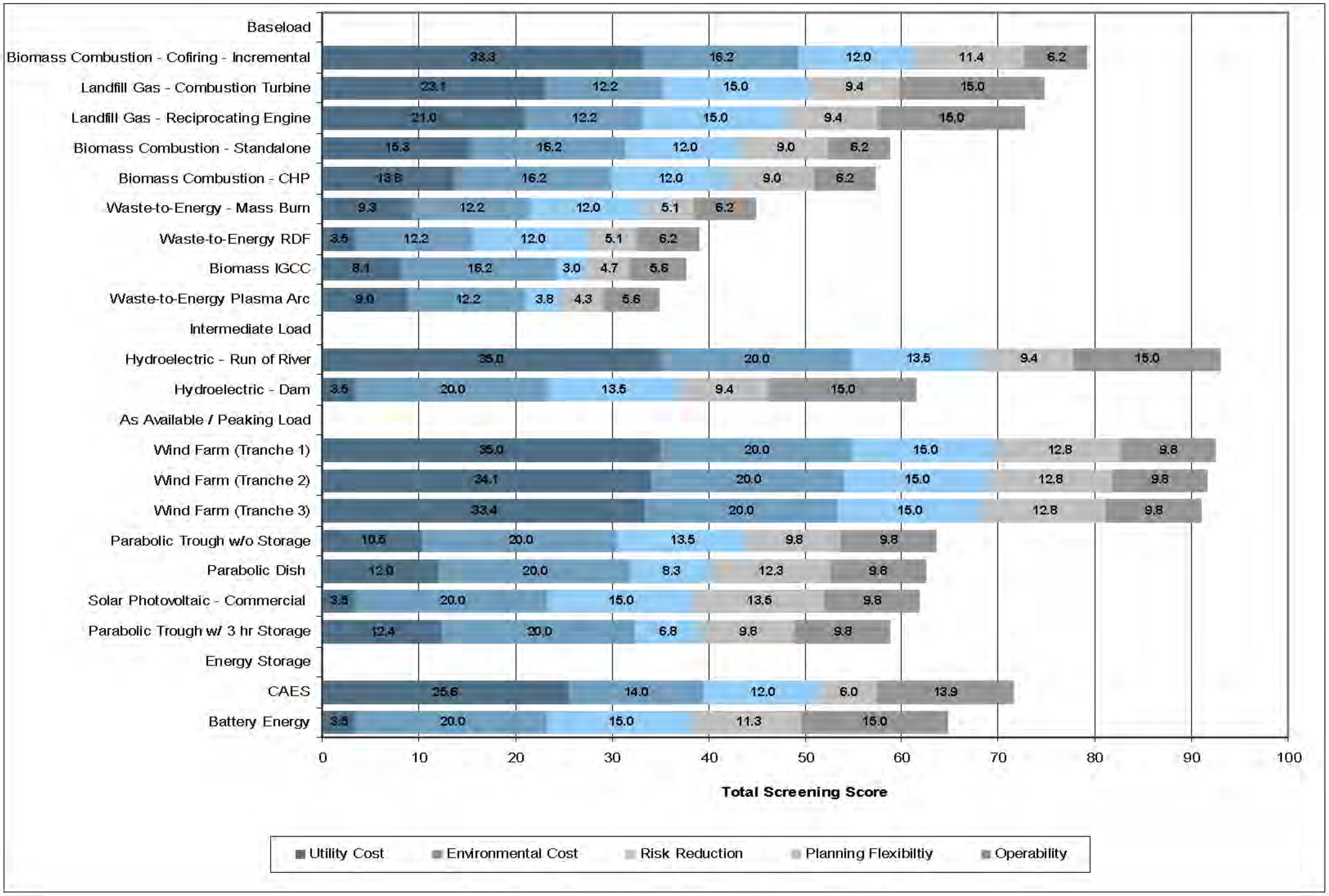


Figure 17 Summary of Scoring Results

Renewable Portfolio Cases

Missouri Senate Bill 54 requires that AmerenUE shall make a good faith effort to generate or procure sufficient electricity generated by eligible renewable energy technology to meet the following renewable generation targets of total retail sales:

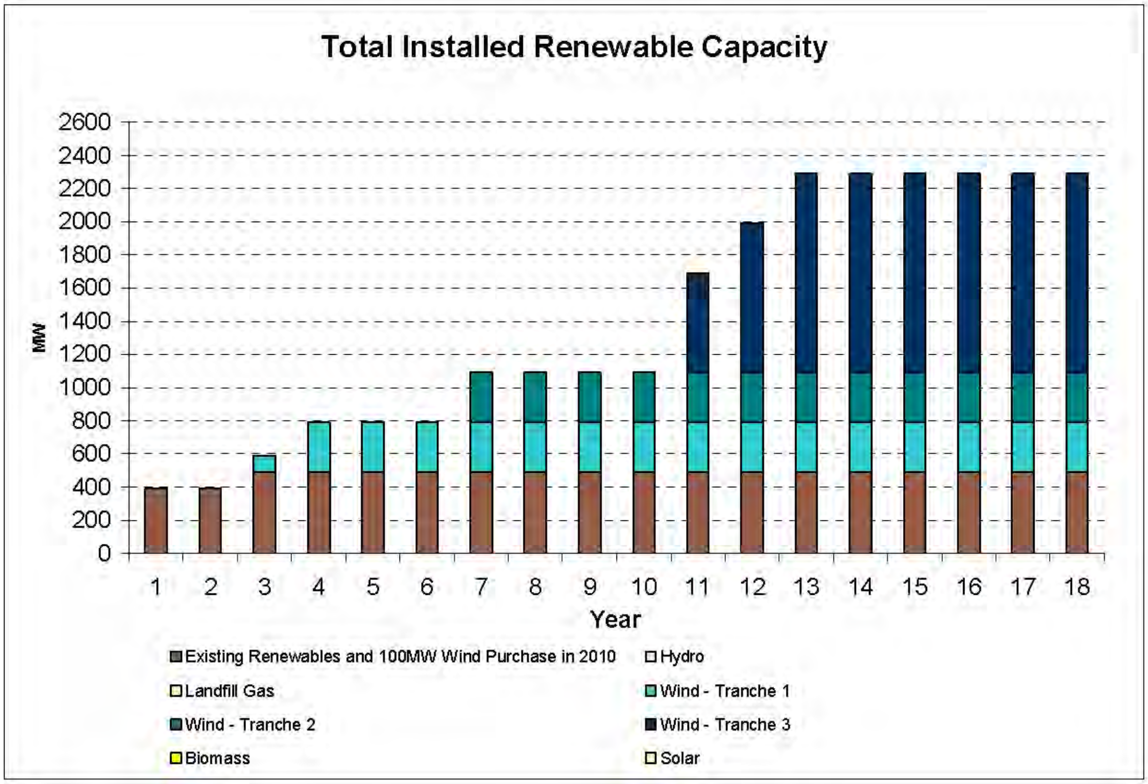
Year	**Energy Target (% of total retail Sales)**
2012	4%
2015	8%
2020	11%

Based on this requirement, five renewable portfolio cases were provided by utilizing the above screened technologies in various combinations. The five renewable portfolio cases are as follows:

- All Wind Renewable Portfolio (RP) Case.
- Moderate RP Case.
- Low RP Case with Wind (including consideration of Demand Side Management (DSM)).
- Low RP Case without Wind (including consideration of Demand Side Management (DSM)).
- High RP Case.

The All Wind Case projects installation of 1,800 MW of wind generation capacity. The installation of this generation capacity is expected to occur in three phases across all of Missouri and portions of Illinois, Iowa, and Kansas. Recognizing that the cost of wind projects would vary depending on the availability of the resource and the capability of the transmission system to deliver power, three cost tranches were established. Cost Tranche 1 includes 300 MW of wind capacity sited in Illinois. Cost Tranche 2 includes the remaining feasible wind capacity in northeast Missouri. Potential wind projects located in northwest Missouri, southwestern Iowa, and Kansas have been included in Cost Tranche 3. Considering the available wind regimes and the advancement of wind turbine technology expected over time, capacity factors for Tranche 1, Tranche 2 and Tranche 3 are 33 percent, 35 percent and 39 percent, respectively.

In the all Wind Case, as shown in Figure 18 the total renewable energy (including existing renewable generation and 100MW wind purchase in 2010) is 6.1% of Ameren UE total retail sales in 2012, 8.1% in 2015 and 16.6% in 2020, which exceeds generation targets established for Missouri Senate Bill 54.



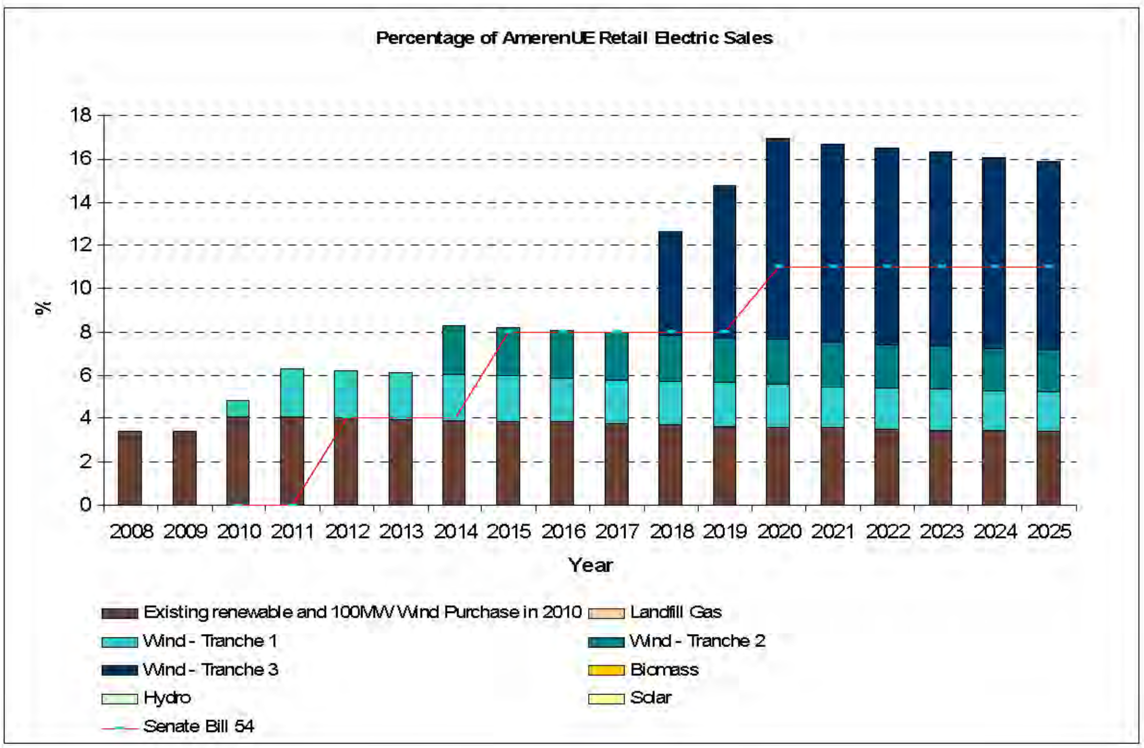
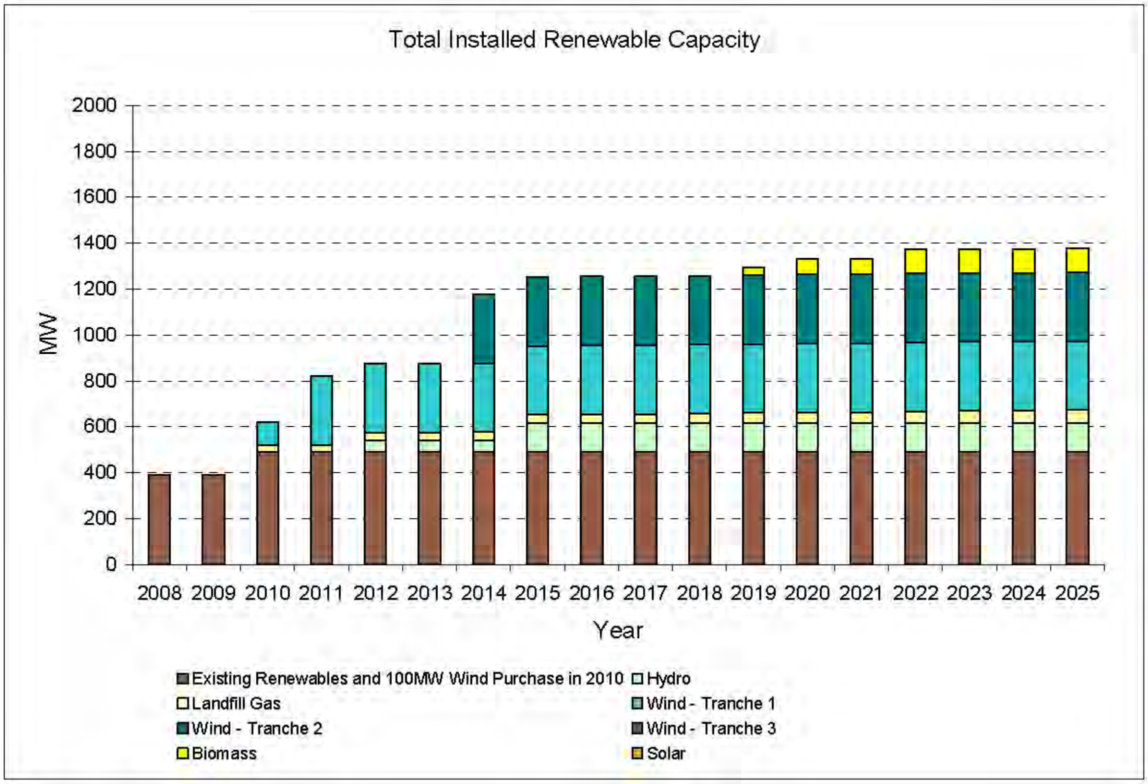


Figure 18 All Wind RP Case

While the Moderate Case renewable generation targets could likely be achieved from wind resources in Missouri and neighboring states, other renewable options may be available that would provide lower costs to AmerenUE. As shown in Figure 19, AmerenUE has assembled a projection of the renewable projects available that would meet the generation targets established in the Moderate Case. The Moderate Case renewable generation energy is 7.6% of Ameren UE total retail sales in 2012, 10.7% in 2015 and 11.3% in 2020, which meets generation targets established for Missouri Senate Bill 54.

It is expected that the available landfill gas, hydro and biomass projects identified in the Moderate Case will all be comparable in cost to Cost Tranche 1 Wind resources. LFG and hydro candidate projects seem well defined and likely could be developed. The renewable portfolio assembled for the Moderate Case includes only one standalone biomass project. By picking and choosing from these projects, it seems the Moderate Case targets could easily be met from the perspective of resource availability. If necessary, additional Cost Tranche 2 Wind projects could be executed to reach the targets defined in the Moderate Case. This analysis does not consider the cost effectiveness of the candidate projects.



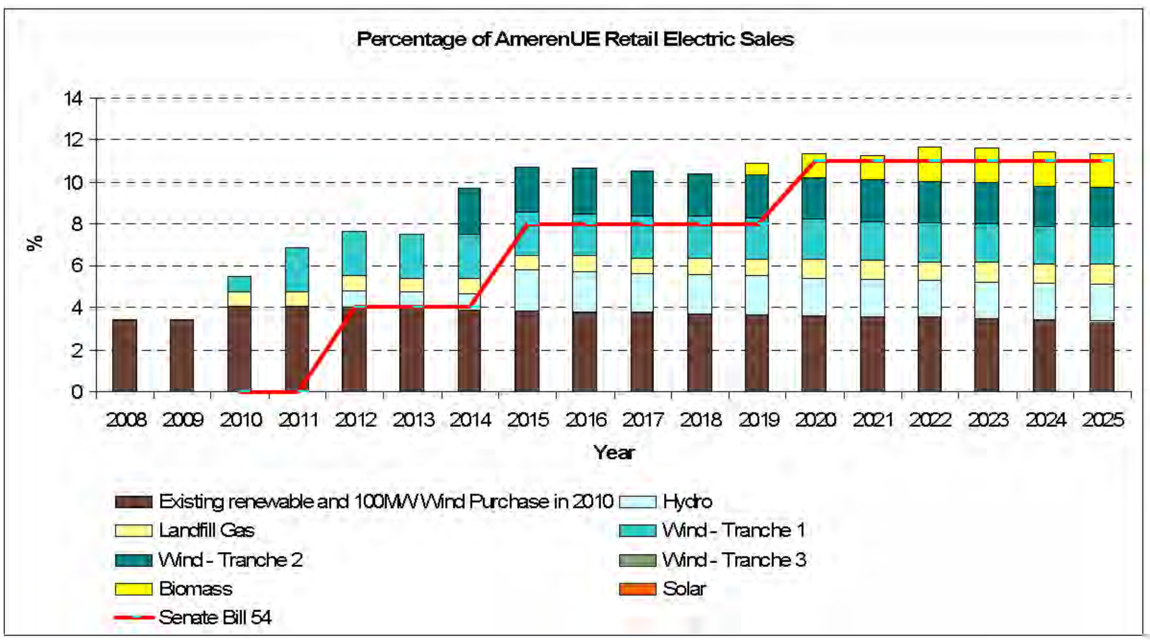
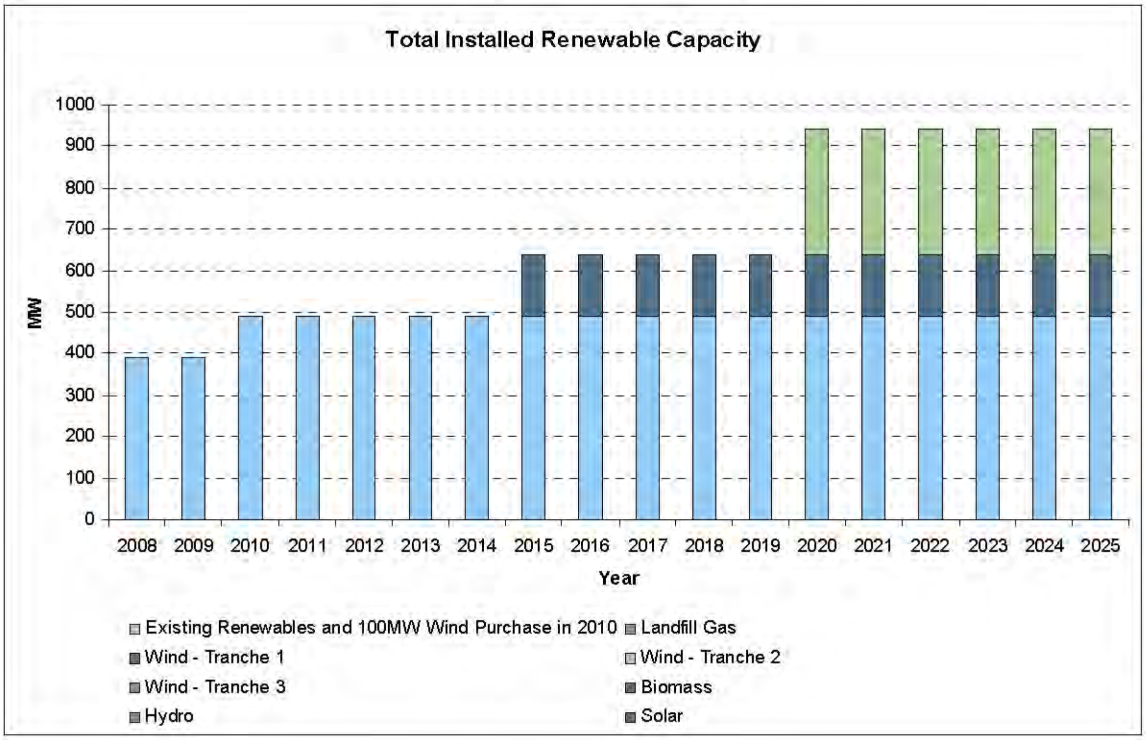


Figure 19 Moderate RP Case

Taking into account the potential of Demand Side Management (DSM), the generation targets of the Low Case with Wind are significantly reduced, as shown in With consideration of DSM, the generation targets can be achieved by relatively modest installation of wind capacity: 150 MW of generation capacity in 2015, supplemented with 300 MW of generation in 2020. This strategy results in shortfall in the targeted generation in 2015, but otherwise surpasses the generation targets set forth in the Low Case with Wind when DSM considerations are included.



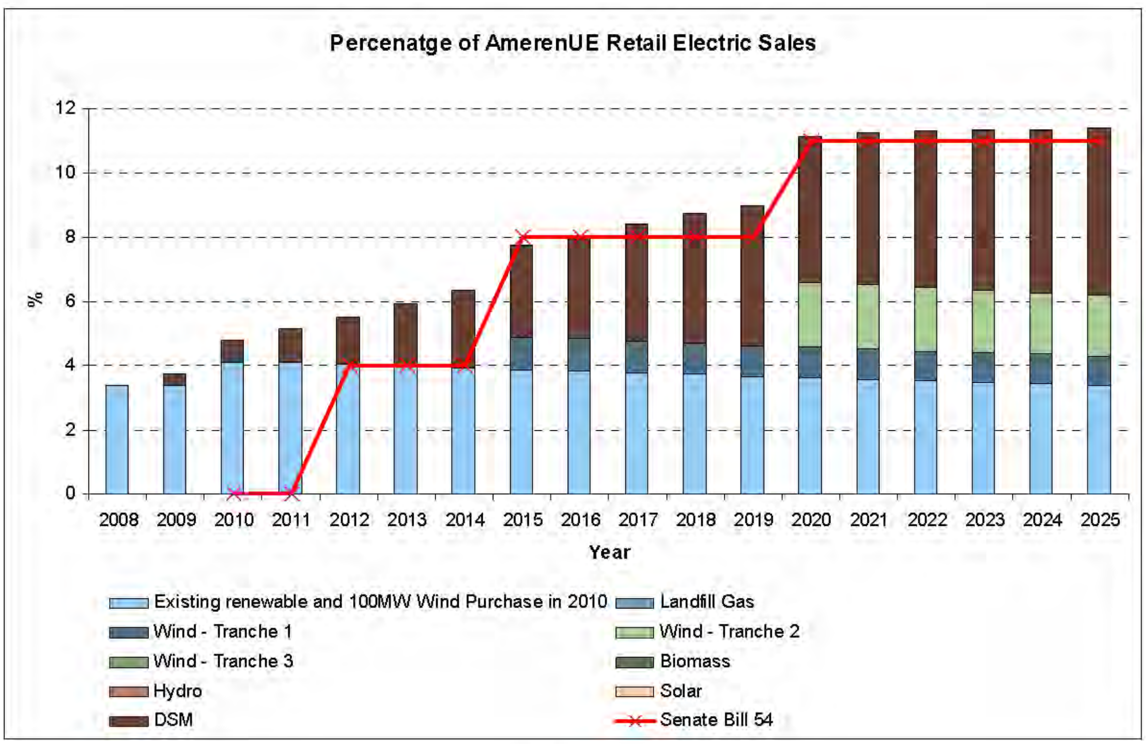
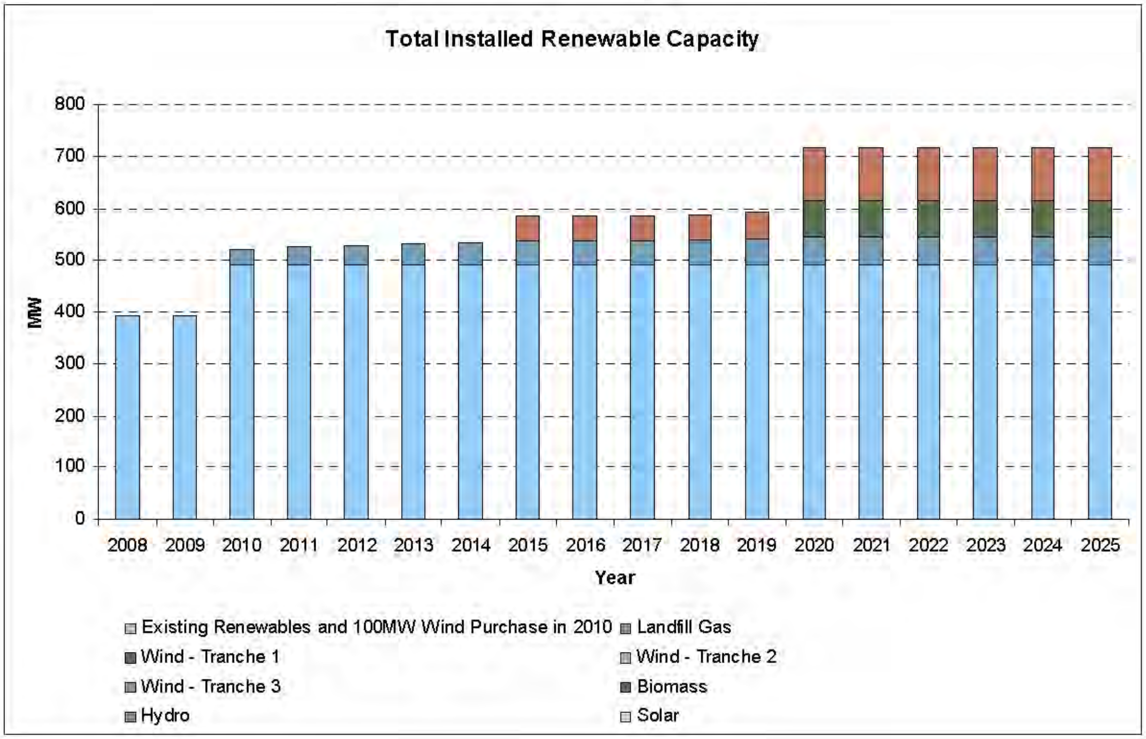


Figure 20

Low RP Case with Wind (including consideration of DSM)

Compared to wind resources, since other renewable options provide lower costs to AmerenUE, another Low Case without wind is achieved from the Moderate Case by removing wind resources. With consideration of DSM, Using Land fill Gas, Biomass and Hydro technology, the generation targets can be achieved by without wind resources, as shown in Figure 21.



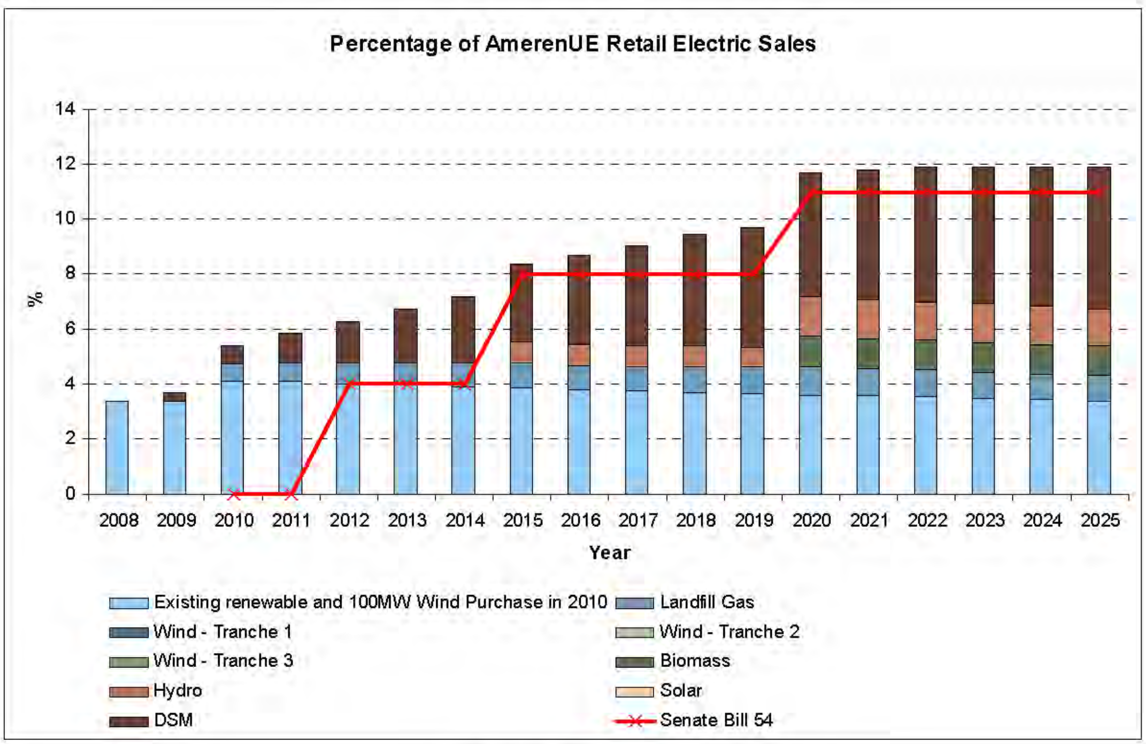
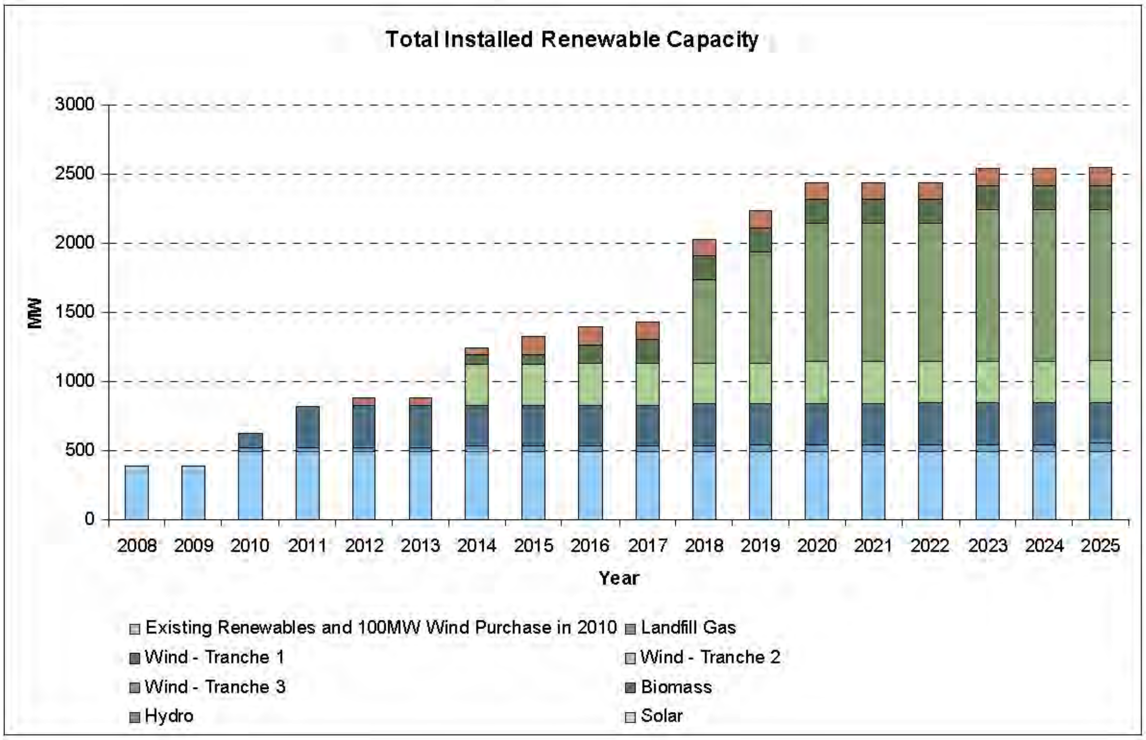


Figure 21

Low RP Case without Wind (including consideration of DSM)

The High Case is not met as readily or as cost-effectively as the Moderate Case. The generation projections shown in Figure 22 use all of the available LFG and hydro opportunities as well as aggressive application of potential biomass resources. The High Case renewable generation energy is 7.6% of Ameren UE total retail sales in 2012, 11.9% in 2015 and 20.5% in 2020, which exceeds generation targets established for Missouri Senate Bill 54.

The hydro projections may be aggressive as well, as they include the use of a proposed technology that is not yet commercially proven. The High Case generation target could be met with a more aggressive wind portfolio projection. Solar technologies have not been considered as likely resources to meet the targets. If they were, photovoltaic cells would be the likely technology choice.



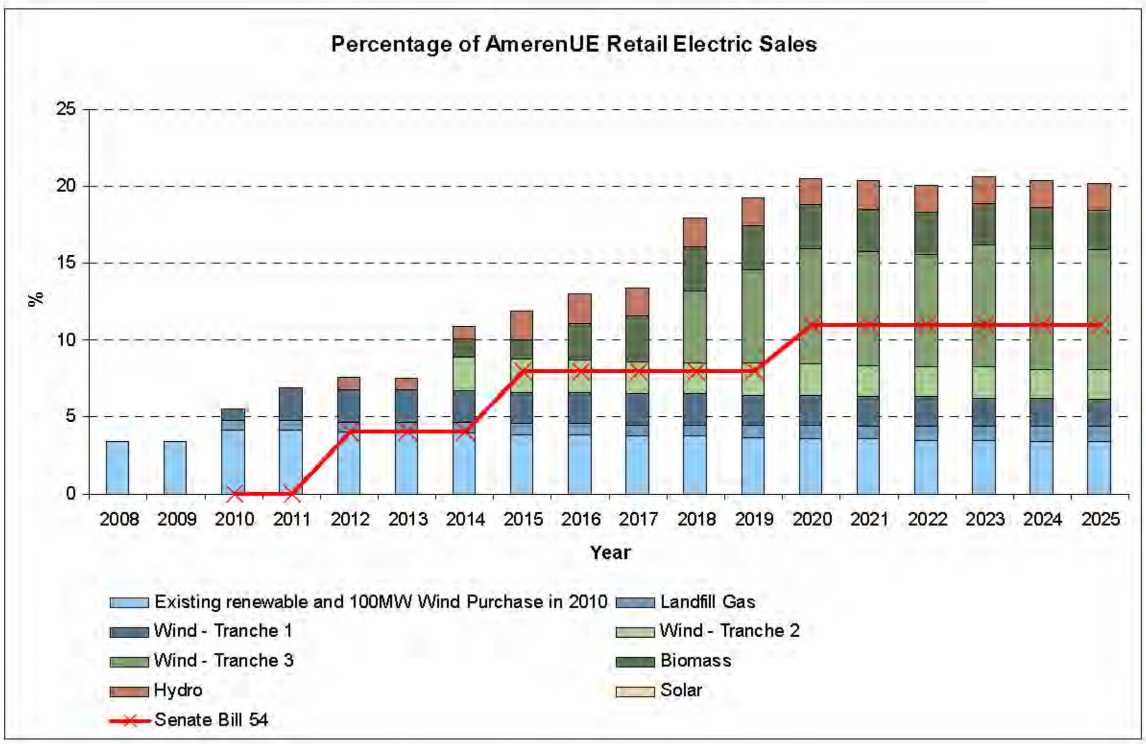


Figure 22 High RP Case

Wind Tiers

For this supply side resource study, wind was categorized in three tiers: Tranche 1, Tranche 2, and Tranche 3. The wind tiers included unique EPC capital costs, capacity factors, and Owner's costs to account for wind tower heights, regional wind resources, and transmission and distribution (T&D) system upgrades.

Where T&D upgrades are required, there would likely be regional benefits associated with some of the upgrades. It is likely that there could be cost sharing for some of those upgrades. However, those factors were not considered in characterizing the wind tranches. Also, production tax credits were not included in characterizing the wind tranches. The following describes the associated wind resource regions and distinct characteristics:

- **Wind Tranche 1** - Wind Tranche 1 would include 300 MW of generation in Illinois.
    - EPC Capital Cost - The EPC capital cost for Wind Tranche 1 was assumed to be the base EPC capital cost among the three tranches.
    - Capacity Factor - An annual average capacity factor of 33 percent was assumed. This is indicative of projects using 80 meter towers, which is currently the commercial standard for American wind projects.
    - Owners Costs - The T&D upgrade Owner's cost requirements for Tranche 1 was estimated at $25,000,000 (±20 percent), and is based on posted system impact studies for existing generation interconnection requests in the MISO Queue.

- **Wind Tranche 2** - Wind Tranche 2 would include 300 MW of generation in NE Missouri/SE Iowa. It is expected that Tranche 2 resources could not come online until 2014.
    - EPC Capital Cost – The EPC capital cost for Wind Tranche 2 includes a nominal cost increase of $200 per kw to account for taller towers.
    - Capacity Factor - Average annual capacity factor for Wind Tranche 2 increases slightly to 35 percent compared to Wind Tranche 1 because the

Tranche 2 projects are assumed to use 100 meter towers. Tranche 2 projects are expected to be developed later than Tranche 1, which would increase the likelihood that taller towers may be used.

- Owners Costs - The T&D upgrade Owner's cost requirements for Tranche 2 was estimated at $35,000,000 (±30 percent), and is based on posted system impact studies for existing generation interconnection requests in the MISO Queue. For wind capacity greater than 300 MW, it is estimated that there would be a substantial increase in the T&D upgrade costs to develop the necessary outlet T&D.

- **Wind Tranche 3** - Wind Tranche 3 would include 400 to 1,200 MW of generation in NW Missouri/SW Iowa or Eastern Kansas. It is expected that Tranche 3 resources could not come online until 2018.
  - EPC Capital Cost - The EPC capital cost for Wind Tranche 3 includes a nominal cost increase of $200 per kw to account for taller towers.
  - Capacity Factor - Average annual capacity factor for Wind Tranche 3 increases slightly to 39 percent compared to Wind Tranche 2. Projects in the Tranche 3 regions are expected to have higher capacity factors than those the other regions. Similar to Wind Tranche 2, Tranche 3 assumes 100 meter towers.
  - Owners Cost – The T&D upgrade Owner's cost requirements for Tranche 3 includes a screening-level estimate of T&D installation and upgrades. These activities are assumed to cost roughly $219,000,000. In addition to transmission upgrades, transmission service costs of approximately $17,000,000 to $25,000,000 per year are expected to be required. This cost is distributed over projects with a generation capacity of 400 MW. Adding more Tranche 3 wind capacity is expected to require more transmission upgrades. A total of 800 MW of Tranche 3 wind is expected to require up to $430 million for transmission upgrades and services.

4 CSR 240-22.040 (3)

The analysis of supply-side resource options shall include a thorough analysis of existing and planned interconnected generation resources. The analysis can be performed by the individual utility or in the context of a joint planning study with other area utilities. The purpose of this analysis shall be to ensure that the transmission network is capable of reliably supporting the supply resource options under consideration, that the costs of transmission system investments associated with supply-side resources are properly considered and to provide an adequate foundation of basic information for decisions about the following types of supply-side resource alternatives:

(A) Joint participation in generation construction projects;

(B) Construction of wholly-owned generation or transmission facilities; and

(C) Participation in major refurbishment, upgrading or retrofitting of existing generation or transmission resources.

AmerenUE's transmission strategy to meet the changing requirements of the utility industry includes least-cost local area planning considering growth and system development requirements, participation in NERC reliability standards development, participation in SERC regional planning activities, participation in regional generation connection evaluations, coordination with the Midwest ISO to improve overall regional operations, and engagement with the Midwest ISO on tariff issues. It is believed that continued active involvement in the various planning processes will maintain a reliable transmission system.

AmerenUE continues to plan its transmission systems following the AmerenUE Transmission Planning Criteria and Guidelines and NERC Reliability Standards to meet the various needs of the customers and to minimize the opportunities for significant constraints that would impact reliability.

AmerenUE routinely performs rigorous analyses of the AmerenUE system throughout a one- to ten-year planning horizon. These studies consider the effects of system load growth, the adequacy of the supply to new and existing substations to meet local load growth, the selection of sites for new generation resources, the changing regional use of the bulk electric system (BES) and the resulting impacts on the reliability of the AmerenUE transmission system. In the event that these studies forecast reduced reliability, additional studies evaluating all practical alternatives are performed to determine what, where and when system upgrades are required. These proposed solutions include applicable new technologies, e.g. Flexible AC Transmission System (FACTS) devices, high-temperature operation conductor, etc., as well as more traditional planning solutions. Distributed generation resources and demand-side management solutions are also considered, if practical and permitted considering applicable NERC standards. The total cost for maintaining system reliability is considered for the expansion options.

AmerenUE participates in national and regional reliability and planning activities through the NERC and SERC organizations and the Midwest ISO (MISO). AmerenUE provides leadership through active participation in NERC and SERC committees, including the NERC Planning Committee, the NERC Transmission Issues Subcommittee, and the SERC Engineering Committee to promote reliability throughout the nation. AmerenUE participates in the SERC study groups and committees responsible for developing near-term and longer-term intra-regional and inter-regional transmission assessments, and in the groups that assess reliability on a SERC regional or sub-regional basis. AmerenUE works through the NERC and SERC processes to provide comments and information to NERC or FERC regarding planning issues, proposed reliability standards, and to request clarifications to existing reliability standards. AmerenUE also participates with the MISO in their annual expansion planning efforts to coordinate and pursue activities associated with the planning, operation, and maintenance of a reliable transmission system. Participation in the MISO planning efforts is the method by which AmerenUE's local plans are "rolled-up" on a regional basis. This regional roll-up provides the opportunity to evaluate regional solutions that may resolve multiple local issues. Through these RTO activities, AmerenUE works to provide a reliable system throughout the Midwest region and to ensure that opportunities for system expansion make sense and would provide the required system benefits while seeking a balance between regional and AmerenUE goals and attempting to minimize cost exposure to AmerenUE customers.

AmerenUE also participates in regional generation interconnection studies for proposed generation interconnections inside and outside of the AmerenUE footprint. AmerenUE responds to requests for proposals from Midwest ISO and performs studies of proposed generation interconnections to the AmerenUE system or AmerenUE participates in the ad hoc stakeholder groups that oversee the studies. Participation in these activities ensures that the studies are performed on a consistent basis and that the proposed connections are integrated into the AmerenUE system and planning processes so as to maintain system reliability. As discussed above, all applicable AmerenUE transmission planning criteria and NERC Reliability Standards are used in evaluating the proposed generation connections. Powerflow, short-circuit, and stability analyses are performed to evaluate the system impacts of the requested interconnections. If system deficiencies are identified in the connection and system impact studies, facility studies are performed to refine the limitations and develop alternative solutions.

AmerenUE also participates with its neighbors in joint planning activities, and in ad hoc committees for interconnection requests in areas outside of AmerenUE which may affect the reliability of the AmerenUE system. In addition, AmerenUE is working with the Midwest ISO to increase participation and coordination in studies involving RTO seams. Participation in these interconnection study activities influences the planning process and leads to a more reliable local and regional BES.

AmerenUE continues to work to improve the overall effectiveness of regional operations within the Midwest ISO footprint. The Midwest ISO methodologies, processes, and business practices for a variety of activities have been evolving since AmerenUE joined the organization. Many of the processes were borrowed from PJM and modified to fit Midwest ISO requirements. Opportunities for improvement continue to exist, but are often hindered by tariff issues.

Tariff issues can also impact transmission system expansion and development. AmerenUE continues to work with the Midwest ISO to ensure that tariffs affecting transmission are reasonable, fair, and equitable.

As discussed above, the AmerenUE transmission system needs to be flexible and robust to serve the needs of all users, including AmerenUE bundled native retail load, for a wide variety of operating conditions. A flexible and robust transmission system is necessary to enable AmerenUE to pursue cost effective capacity and energy alternatives to serve its customers as well as meet any renewable energy targets established by legislation or directive.

Updates to AmerenUE's transmission plans are provided to the Midwest ISO twice a year for model-building and other planning and reporting activities. The more significant projects are included in the Appendix A of the Midwest ISO transmission expansion plan (refer to Appendix A information on the Midwest ISO web site. Information to be provided to the Midwest ISO for their next expansion plan will note the projected completion of the following AmerenUE projects:

1. Loose Creek-Mariosa Delta 345 kV line and Mariosa Delta 345/161 kV substation in 2008
2. Joachim 345/138 kV substation in 2008

Appendix A of the Midwest ISO transmission expansion plan (MTEP) also includes the major transmission connections and upgrades planned for the AmerenUE system to support large generation interconnections. Some of these are associated with the proposed 1,650 MW Prairie State Energy Campus, located in Washington County, Illinois, approximately 35 miles southeast of St. Louis. The Prairie State project, including a 28-mile Baldwin-Rush Island 345 kV transmission line, is a significant enhancement to the AmerenUE system in the St. Louis metropolitan area. In addition, over 1000 MW of coal and 4000 MW of wind development have been proposed for interconnection studies in the AmerenUE-Illinois footprint, and some of these are in various stages of study. A few wind projects (totaling about 600 MW) have been proposed in the northern part of the AmerenUE footprint. AmerenUE is also considering a second Callaway nuclear plant addition in the mid-to-late 2010s; with some transmission analysis already completed and other studies waiting to get underway.

The Midwest ISO has been coordinating the planning activities of its members since the first Midwest ISO expansion planning effort in 2003. To date the Midwest ISO has had very little impact on the network upgrades identified in the AmerenUE planning processes. Local transmission plans continue to be rolled-up to the regional level, but no AmerenUE projects have been modified and no additional AmerenUE network upgrades have been proposed to meet regional goals. The Midwest ISO planning process continues to evolve with a long term goal to develop a robust transmission system to provide for regional reliability and to support a regional market.

The Midwest ISO has developed a method to assess the deliverability of generation within the Midwest ISO market. While this test is more typically associated with unregulated generation, it is the default test which the Midwest ISO uses to evaluate all generation within its footprint. Generation which passes this test can be designated as a network resource by any load in the Midwest ISO footprint (or in the case of AmerenUE, designated to serve the native AmerenUE bundled load). Generation that fails this test can either participate in the Midwest ISO market as an energy resource, which cannot be designated for capacity resource purposes, or the generation could alternately seek to establish limited deliverability to a specific load, such as to the AmerenUE bundled load. All AmerenUE generation in service, except for 63 MW of Audrain generation, has been determined to have regional deliverability and therefore can be designated as a network resource for AmerenUE bundled load. A facilities study to remove the transmission limitation associated with Audrain generation and allow regional deliverability for the entire plant has been requested. The latest MISO list of generator deliverability test results is available at the Midwest ISO website.

NOTE: The projects and recommendations identified in this filing are intended to comply with a Missouri Public Service Commission planning process to address load growth in response to projected increases in demand. Accordingly, requirement references to specific projects do not constitute a permitting determination by AmerenUE. Such evaluations and determinations are complex and require consideration of variables that are beyond the scope of this report.

4 CSR 240-22.040 (4)

The utility shall identify and analyze opportunities for life extension and refurbishment of existing generation plants, taking into account their current condition to the extent that it is significant in the planning process.

For the existing facilities these options within the scope of our work include continued operation and routine maintenance, repair and replacement (RMRR); efficiency improvements and reduction of the utility's own use of energy.

Our process included three steps, and following are details of each stage.

- Identify resource options
- Qualitative Engineering Feasibility Screening
- Preliminary Screening: Cost and Performance Details

Identify Resource Options

Under this step, meetings and one on one dialogue were held with various personnel in AmerenUE, including senior management, plant, engineering, and corporate staff.

Discussion started with the general direction for resource planning by senior management. Fundamental objectives focused on safe and reliable power for AmerenUE customers. Additional discussion was held regarding identification of key stakeholders at the plants and the corporate office. Stakeholder involvement of key suppliers was also a discussion topic. The general direction yielded the following results presented at **Stakeholder Meeting #1:**

- **Historic Performance**
- **Description of plants**

- **Identification of Reasonable Potential Options**
- **Clarification items for existing plants**

Identification of reasonable potential options focused on 4 areas. Efficiency Improvements, Auxiliary power reduction, RMRR/Capacity/Restoration Enhancement and continued operation projects.

NOTE: The categories and projects set forth below are intended to optimize the performance of various equipment, components, operating processes and existing facilities. Such projects and process improvements are not intended to increase steam flow or result in an increased consumption of fuel.

1. **<u>Efficiency improvements</u>**

   i. Improve turbine efficiency with select hydro and steam component upgrades.

   ii. Maintain design thermal plant (boiler) efficiencies.

      1. Routine/Real time (EtaPro) Performance Testing of boilers/turbines for baseline design efficiency.
      2. SH and RH steam temperature/pressure design ratings
      3. Reduction in boiler air-in leakage for ID fan power
      4. Modifications to air heater seals to improve efficiency
      5. Monitor and repair to achieve FGET as designed
      6. Sootblower optimization to improve heat transfer
      7. Evaluate and repair steam valves for leak through
      8. Expanded monthly efficiency reporting by plant.

   iii. International Peer Efficiency review process leadership, Asian-Pacific Partnership with electric utility engineers from US, China, Japan, South Korea, Australia, and India.

   iv. Neural network artificial intelligence for combustion optimization

2. **Auxiliary power reduction**
    i. Investigate auxiliary power usage target of 5% at the power plants.
    ii. Variable speed drives (VFD's) for large single speed motors in cycling duty applications.
    iii. Evaluate high efficiency Motors, Lighting, Cooling and transformer upgrade projects.

3. **Plant RMRR** and **Capacity enhancements**

   The key initiatives identified as reasonable potential options include the following.

   a. LP turbine upgrades – Carry forward, 11 completed, 9 planned, 8 of 9 in 2008 Integrated Resource Plan Response -70 MW estimate
   b. Hydro turbine runner upgrades – Carry forward, 16 MW estimate
   c. HRSG combine Cycle Repowering – Carry forward
   d. Precipitator advanced controls – Carry forward, 5 MW estimate
   e. CTG Power Augmentation – Not carried forward, additional research required
   f. Audrain CT facility upgrade – Not carried forward, extensive engineering required
   g. Condenser upgrades – Not carried forward, additional engineering required.
   h. Boiler Slag diverters – Not carried forward, pilot project, no capacity increase.
   i. Intake condenser discharge wave power – Not carried forward. New technology requiring additional study
   j. Synfuels and Biofuels – Not carried forward, new unit application only.
   k. Labadie cooling towers – Not carried forward, extensive engineering required.

4. **Analysis of Continued Operations**

   Evaluation of continued operation options versus plant/unit retirement analysis is an integral part of AmerenUE resource planning. Such analysis, however, involves a significant degree of uncertainty.

   Retirement analysis deliverable will be a "Process of Decision Making" on how continued operation dates will be determined. The following steps will be included.

   a) Safety of continued plant operations.
   b) Fuel patterns and availability of fuel for the boilers

c) New and revised Environmental regulations at the City, County, State, Federal and International level.
d) Availability of new confirmed technologies for fossil fuel combustion.
e) Utilization of coal combustion by-products and landfill implications.
f) National and international competition and scheduling of new and upgraded equipment fabrication.
g) Condition assessment of the various boiler, turbine and coal handing components.
h) Impact on system reliability and availability.
i) Operational and Financial risk assessments.

<u>Qualitative Engineering Feasibility Screening</u>

Upon completion of identification of resource options, the process moved to quantitative screening of potential supply side options. Each technology or initiatives was analyzed independently.

Qualitative screening included significant collection of data (Pre-analysis & Analysis).

This was followed by Cost and Performance details being developed for each option including installation capital, Operational cost, and installed cost per KW. Technologies and initiatives were also evaluated for deployment readiness and maturity.

The next step was the Development of Uncertain Factors (Risk Factors). This would lead to Preferred Plan Selection. Also to be included would be resource screening for cost, scheduling, probabilities, etc. Action steps included the following:

1. Review the current assets in the existing fleet.
2. Identify reasonable potential options in the following areas:
    a. Efficiency Improvements
    b. Auxiliary power reduction
    c. Continued Plant Operations

   d. RMRR/Performance Optimization
3. Review of historic, current or budgeted projects in above 4 areas.
4. Complete a Risk/Opportunity analysis with plant personnel.
5. Identification of the Continued Operation versus Retirement process.
6. Complete the Carry Forward analysis by internal and external stakeholders.

A team was developed and pecific responsibilities in these areas were given to the group representative. Discussion held with stakeholders centered on identification of equipment limitations, and operating issues at the Labadie, Rush Island, Sioux and Meramec fossil plants. Similar dialogue was held on issues pertaining to the hydro plants of Osage and Keokuk, as well as the various Combustion Turbine sites.

Group meetings were held to identify internal and external resources required to complete a thorough identification of options and option analysis. Firms considered included Black and Veatch, Burns and McDonnell, and Sargent & Lundy. A scope of work was developed to use for awarding option identification to an external engineering firm.

It was determined that the existing plant option identification could be completed without use of external engineering consultants. Meetings were held with representatives from the different coal, hydro and CTG plants to identify and review options at their site.

The process used was a brainstorming session that resulted in the following conclusion presented at **Stakeholder Meeting #2 on July 13, 2007:**

Projects with potential to increase or restore the capability of the plant.

Technology Description	Capacity increase restoration (MW)	Capital cost (1,000's)	Operation Costs	Technology Maturity	$/KW Installed	Comment
Labadie Cooling Towers	400K mwhr	[redacted]	TBD	High		Missouri River site
LP Turbine upgrades	70	[redacted]	N/A	High	$ [redacted]	Project history
ES Precipitator Advance Controls	5	[redacted]	N/A	High	$ [redacted]	
Air heater Slag Diverters	Mwhrs not capacity	[redacted]	N/A	Low	$ [redacted]	Trial project
Total Coal enhancements	**75**					
Technology Description	**Capacity increase restoration (MW)**	**Capital cost (1,000's)**	**Operation Costs**	**Technology Maturity**	**$/KW Installed**	**Comments**
Osage and Keokuk turbine runner upgrades	16	[redacted]	N/A	High	[redacted]	9 units completed
Combustion Turbines						
Venice HRSG Repowering	175	[redacted]	TBD	High	$ [redacted]	Reference B&V study
Multi-site mass flow power augmentation	TBD	TBD	TBD	Moderate	TBD	Multiple technology options
Audrain Facility upgrade	24	TBD	TBD	High	TBD	

Projects with potential to improve the efficiency of the plant

Technology/Initiative Description	Capacity increase restoration (MW)	Capital cost (1,000's)	Operation Costs	Technology Maturity	$/KW Installed	Comments
Fouling and FGET losses	N/A	TBD	TBD	High		Analysis underway
Boiler-Turbine efficiency improvements	N/A	TBD	TBD	High		7% Thermal efficiency improvement
High efficiency motors, lighting, HVAC, transformers	5	[redacted] [redacted]	TBD	High	[redacted]	TBA
Auxiliary Power Reduction	TBD	TBD	TBD	High		Best in class
Variable Frequency Drives	N/A	[redacted] [redacted]	TBD	Moderate		7000 mwhrs
Stainless Steel Condensor Upgrades	N/A	TBD	TBD	Moderate		10-75MW biofouling load limitation worst case

Projects with potential to extend the life of the plant

Technology/Initiative Description	Capacity increase restoration (MW)	Capital cost (1,000's)	Operation Costs	Technology Maturity	$/KW Installed	Comments
Sub-critical to Ultra Supercritical Repowering	60 – 75	Estimate not available	Unknown	Very Low	unknown	Potential inclusion in 2011 IRP Filing
Meramec retirement analysis						Environmental, Safety, Engineering, and Financial analysis

Preliminary Screening: Cost and Performance details

After concluding qualitative analysis, existing plant items were selected for inclusion as Candidates for Preliminary Screening. Cost and performance details were identified and characterized. This information summarized the remaining options in one of the following two areas:

- Specific options NOT passed and reasons
- Specific options passed and reasons (with estimated costs and savings)

The next steps in the preliminary screening analysis included the four items below.

1. Identify potential capacity increase/restoration, associated costs, and implementation timing.
2. Review the detailed process of decision making for plant life extension and retirement.
3. Development of a Plant retirement analysis timeline.
4. Submit details to Black & Veatch for inclusion in Preliminary Screening.

The following items were passed on to Preliminary Screening for inclusion in the Black and Veatch summary. They were also presented in IRP Stakeholder Workshop #3 on August 14, 2007.

AmerenUE Existing Plant Resource Options
Preliminary Screening Information and Data
PASS-ON Options

Initiative	Status
Steam Turbine Upgrades	Passed
Hydro Turbine Upgrades	Passed
Venice HRSG Repowering	Passed
Electrostatic Precipitators	Passed
Variable Frequency Drives	Not Passed
Auxiliary Power Reduction	Not Passed
Audrain Facility upgrade	Not Passed
CTG Power Augmentation	Not Passed
Labadie Cooling Towers	Not Passed
Air heater slag diverters	Not Passed

1. **LP turbine replacement – STATUS: PASS ON**

This project involves capital upgrades to the Low Pressure steam turbines at several of the large fossil plants identified below. The total steam turbine upgrade is 70 megawatts.

In progress: Labadie Unit 1. LP turbine #1 and LP turbine #2. Increase in output of 20 MW. Cost of upgrade is $18 Million. The timeframe for this upgrade is the spring of 2008. The 20MW associated with this project are accounted for in the current system capacity.

The remaining items are future planned projects representing the 70MW included in the 2008 Integrated Resource Plan.

a. Rush Island Unit 2. LP turbine #1 and LP turbine #2. Increase/restore in output of 15 MW. Cost estimate of upgrade i[redacted] Most likely timeframe for upgrade installation is 2009.
b. Rush Island Unit 1. LP turbine #1 and LP turbine #2. Increase/restore in output of 15 MW. Cost estimate of upgrade i[redacted] Most likely timeframe for this upgrade installation is 2012.
c. Labadie Unit 2. LP turbine #1 and LP turbine #2. Increase/restore in output of 20 MW. Cost estimate of upgrade is[redacted] Most likely timeframe for this upgrade is 2011.

d. Meramec Unit 3. LP turbine and HP turbine. Increase/restore in output of 20 MW. Cost estimate of upgrade i[redacted] Most likely timeframe for this upgrade is 2010.

2. <u>Osage and Keokuk turbine upgrades – STATUS: PASS ON</u>

<u>In progress:</u> Osage Unit 1 - 7.5 MW. Osage Unit 7 - 7.5 MW, [redacted] cost estimate each. These projects are currently underway. The 15 MW associated with these 2 projects are accounted for in the current system capacity.

The remaining items are future planned projects representing the 16 MW included in the 2008 Integrated Resource Plan. Likelihood and magnitude of relicense cost have not been estimated or included.

a. Keokuk Unit 1 - [redacted] 2 MW
b. Keokuk Unit 2 - [redacted] 2 MW
c. Keokuk Unit 3 - [redacted] 2 MW
d. Keokuk Unit 4 - [redacted] 2 MW
e. Keokuk Unit 5 - [redacted] 2 MW
f. Keokuk Unit 6 - [redacted] 2 MW
g. Keokuk Unit 14 - [redacted] 2 MW
h. Keokuk Unit 15 [redacted] 2 MW

3. <u>Electrostatic Precipitator Upgrades – STATUS: PASS ON</u>

This project involves installation of new power supplies and transformer/rectifier sets on the precipitator controls at the fossil plants. Cost estimates for these controls are [redacted] and should reduce the auxiliary power required to operate the precipitators (~5MW).

a. Labadie Units 1, 2, 3 and 4 - [redacted] Power Savings of 2 MW @ full load with all 4 units.
b. Rush Island units 1 and 2. [redacted] Power savings of 700KW @ full load with both units.
c. Sioux Units 1 and 2 [redacted] Power savings of 900 KW @ full load with both units.
d. Meramec Units 3 and 4. [redacted] Power savings of 1 MW @ full load with 4 units.

4. <u>Callaway Unit #1 Plant Upgrade – STATUS: PASS ON</u>

In addition to the fossil and hydro plant opportunities identified above, a potential upgrade for Callaway Unit #1 was identified. An upgrade to Callaway Unit #1 is being considered and will be studied in greater detail. The upgrade is expected to result in an additional 70 MWs and cost approximatel[redacted] The extent of the modifications necessary to complete the upgrade is not fully known but is expected to involve changes below. The implementation plan outlines the major milestones and schedule for completing the feasibility study.

- Main Electric Generator - The generator is loaded to it's maximum capacity. A re-wind can not add enough bars for the expected power increase. The generator will be replaced with a larger frame size to accommodate the added load.
- Main Step Up Transformers - The main step up transformers are also operating at their maximum capacity. A larger transformer is required to accommodate the added load.
- HP Turbine - It is anticipated the HP turbine will need to replace the nozzle plates to allow for the steam flow increase associated with the proposed power up rate. The existing nozzle plates have approximately 5% excess flow capacity. The expected steam flow increase for the proposed up rate is approximately 9%.
- Reactor Head Replacement - The reactor head is being replaced to mitigate the alloy 600 issues present in the industry. The change in reactor temperature for the power up rate could potentially reduce our safety margin as currently installed. The replacement reactor head would restore the safety margins.

5. <u>Venice HRSG Repowering – STATUS: PASS ON</u>

Screening assumptions, energy and cost data were developed in previous engineering studies initiated by Ameren. The Venice plant is the site of the 2005 installation of 2 x 501FD2 units. These units were designed with potential for heat recovery steam generation (HRSG) retrofit, Combined cycle configuration. This creates an opportunity to install a 175MW HRSG for steam production using the discharge energy from the combustion engines.

An estimate for this Repowering project is [redacted] The major components required includes the HRSG boiler, By-pass damper system, Steam turbine-generator and Circulating water system. Black &Veatch supplied data for detailed screening analysis.

The following technologies and initiatives **were not passed** on to preliminary screening. These none selected initiatives require additional analysis and/or engineering studies for feasibility scoring. The rational for none selection is included.

6. Variable Frequency Drives: STATUS – NOT PASSED

This project involves identification and selection of large motors with variable load application. Typical characteristics include:

a. Motors sized at or greater than 5000 horsepower
b. Variable load range with at least 70% load factor.
c. Duration of time at reduced load factor of 8 hours per day.
d. Estimated power saving of 800 kw/hour.
e. Assumed 1 application at each of the 4 major fossil plants.
f. Installation cost estimate of $30/horsepower for VFD equipment.
g. Purchase cost estimate of $75/horsepower for VFD equipment.

The next steps associated with this initiative include continued engineering analysis of variable frequency drives for reliability. Identification of the design, purchase and installation cost will be required. Analysis of potential vendors and cyclic duty applications will be performed.

7. Auxiliary Power Reduction: STATUS – NOT PASSED

This project represents megawatt capacity from the use of high efficiency motors, lighting, transformers, and HVAC equipment. The 5 MW associated with precipitator controls is a subset of auxiliary power reduction. Plant specific reviews need to be completed.

Currently the following order of magnitude estimates are representative of auxiliary power usage reduction potential. This energy conservation will be further categorized in specific plant studies to determine options to reduce owner's energy use and associated cost vs. magnitude. Additional boiler-turbine thermal efficiency improvement opportunities will also be evaluated.

a. Labadie aux power usage is 4.7%, representing an industry best practice.
b. Rush Island aux power usage is 5.7%. Potential for reduction from 5.7% to 5.3%, representing 30,000 mwhrs.

c. Meramec aux power usage is currently 6.7%. Potential for reduction from 6.7% to 6.2%, representing 50,000 mwhrs.
d. Sioux aux power usage is 6.3%. Potential for reduction from 6.3% to 6%, representing 20,000 mwhrs.
e. Preliminary auxiliary power energy saving totaling 100,000 mwhrs.

8. Combustion Gas Turbine Power Augmentation: STATUS – NOT PASSED

This project involves various methods to the increase mass flow volume of combustion turbines. Methods include fogging, wet compression, Pre-cooling, combustor upgrades, and increased engine firing temperature >2050 degrees F. Additional engineering study required is required to evaluate and select the appropriate technology. These potential upgrades involve major engine modifications/bucket replacements, design and installation of demineralizer systems, and high pressure pump/nozzle systems. Next Steps include engineering analysis of mass addition & combustion systems, evaluate impact on turbines, and determine life cycle cost of new power augmentation systems.

9. Audrain Facility upgrade: STATUS – NOT PASSED

This project involves potential capacity available at the Audrain Combustion Turbine Generator facility. There may be transmission constraints on the facility. Detailed engineering analysis will be completed to fully evaluate the facility. The next steps include a study by the MISO group which has been requested to review transmission constraints. The study scoping call was scheduled and completed on September 27, 2007 involving MISO and other appropriate parties. Study results will be reviewed by AmerenUE Transmission, Plant and Energy Trading personnel.

10. Air heater Slag Diverters: STATUS – NOT PASSED

This project involves installation of ash diverters on large tangential pulverized coal boilers to minimize convection pass ash pluggage. A trial project was launched at the Rush Island plant during the spring of 2007. Our next steps include a period of study and observation monitoring over an extended period of 12 to 24 months to evaluate effectiveness. If this proves effective in preventing or significantly minimizing ash fouling, we will evaluate this option on other AmerenUE units.

11. <u>Labadie Cooling Tower: STATUS - NOT PASSED</u>

This project involves the design and installation of concrete cooling towers to supplement the Missouri River cooling capacity at the Labadie power plant. Extensive additional engineering and plant studies are required. Next steps include a complete engineering analysis of cooling towers and thermal heat exchange rates. Evaluation of system designs, system cost and system installation options for cooling towers will also be required.

4 CSR 240-22.040 (5)

(5) The utility shall identify and evaluate potential opportunities for new long-term power purchases and sales, both firm and nonfirm, that are likely to be available over all or part of the planning horizon. This evaluation shall be based on an analysis of at least the following attributes of each potential transaction:

(A) Type or nature of the purchase or sale (for example, firm capacity, summer only);

(B) Amount of power to be exchanged;

(C) Estimated contract price;

(D) Timing and duration of the transaction;

(E) Terms and conditions of the transaction, if available;

(F) Required improvements to the utility's generating system, transmission system, or both, and the associated costs; and

(G) Constraints on the utility system caused by wheeling arrangements, whether on the utility's own system, or on an interconnected system, or by the terms and conditions of other contracts or interconnection agreements.

AmerenUE solicited professional services from qualified firms to assist in identifying, collecting data, and screening potential power purchase agreements per the requirements in Supply-Side Resources Analysis (4 CSR 240-22.040 Appendix M).

Burns & McDonnell (B&Mc) was engaged to develop the Request For Information (RFI) (4 CSR 240-22.040 Appendix N). B&Mc emailed the RFI directly to the bidder's that expressed interests as well as posted announcements on various industry web pages. The announcements pointed interested parties to a web site where they could obtain copies of the RFI. B&Mc collected questions, proposed answers to AmerenUE, and posted the questions and answers to the web site. They received, opened, and screened the proposals. This task was done in private. After they had the conforming proposals identified, they performed a bus bar analysis using levelized cost comparisons of the various offers.

An RFI was developed (4 CSR 240-22.040 Appendix O) to solicit brief descriptions of proposed resource options and information from parties who may have or be developing supply side resources that would be of benefit to AmerenUE. The RFI solicited information on capacity and energy sources that could be used by AmerenUE to satisfy its reserve and load serving obligations starting in approximately 2014. Options were solicited for peaking, intermediate and base load type operations. The RFI indicated a variety of contracting options for these resources would be consideration as part of the planning process. The RFI sought only indicative offers and pricing terms. The RFI was issued on June 1, 2007. Information submittals were due on July 13, 2007.

No proposals were received for peaking and intermediate plants. Two responses were for traditional pulverized coal plants being developed in the area. The responses were received from the following companies:

1. [redacted]
2. [redacted]

[redacted]

The [redacted] response included an offer from the [redacted] located in [redacted] The project has obtained all permits required and has been approved for construction. The project is nearing financial close, which is expected for [redacted] The offer provided is for an ownership share of [redacted] in the project. Subsequent inquiries about the potential to obtain additional capacity indicated that additional capacity would be available through a Power Purchase Agreement arrangement. [redacted] was unwilling to provide specifics on the PPA option in the open forum of the AmerenUE IRP process. Verification of full project deliverability to the MISO market was provided by [redacted]

The project cost includes all typical development, transmission and Owner's development type costs. Costs do not include AFUDC or the AmerenUE owner's costs associated with its participation in the project. The project costs can be subject to increase or decrease as the EPC contract is not a total project wrap. According to information submitted by [redacted] the contracts for the Engineer, Procure, Construct and Manage (EPCM), Air Quality

Control System (AGC), Steam Turbine/Generator, and Boilers have been executed. Therefore, pricing should be fairly well defined at this point.

During the analysis, additional information was requested of [redacted] about emissions, inflation and other factors. In addition, information was requested about additional capacity that might be available from the plant. The response from [redacted] is included below:

> "Equity participation in the project is sold out. Regarding potential PPA sales, we do not desire to negotiate for such services in a quasi-public forum. Therefore we do not intend to submit any additional information."

The [redacted] Based on the above response, no further analysis of the Prairie States project was performed.

[redacted]

Transmission interconnection and delivery issues are not finalized for any of the [redacted] facilities. [redacted]

[redacted] would only send information about a project upon execution of a separate Confidentiality Agreement (CA) for that project. A CA was executed between AmerenUE and [redacted] for the [redacted] Information was submitted for the [redacted] The offer was for a Unit Contingent Power Purchase Agreement arrangement. [redacted] indicated that equity participation may be an option, but provided no details of such an approach.

The following points provide information from [redacted] on major issues associated with the project:

1. Due to the early status of development for this project, the cost values for [redacted] should be considered subject to change as the plant is developed. Contingency expected due to construction cost escalation and other financing assumptions are included in [redacted] expected capacity price range of [redacted] month to [redacted]
2. The escalation rates for the fixed and variable O&M and fuel charges is expected by [redacted] to be approximately 2.5 percent.
3. [redacted] Burns & McDonnell considers the [redacted] to be tight for a coal plant of this size. Typical site area allocations by Burns & McDonnell for this size facility are in the area of 850 acres. The impacts of a small site could be manifested in smaller coal reserves, less property for ponds and ash disposal areas, and isolation from neighbors, prompting noise and dust emission complaints.
4. The [redacted] is in the early stages of development. No permitting or transmission study final results are available. Any costs associated with the transmission system improvements necessary for full delivery to the MISO market could increase the costs indicated in the attached information.
5. The plant site has rail delivery from two rail companies. The plant is expected to be fired on Powder River Basin fuel. The fuel deliverability and pricing would have typical uncertainties for this fuel as in other plants being considered in the IRP.

A simplified milestone schedule for the [redacted] development was provided by [redacted]

6. They are currently in final stages of the system impact study process with MISO and expect full deliverability analysis with the facility study in the 1st quarter 2008;

7. The PSD construction permit draft application was submitted and reviewed. The final application submission is planned for September. They expect to obtain the permit 2nd quarter 2008;
8. [redacted] expects to submit the [redacted] application in the September/October time frame. They plan on obtaining the certificate in 2nd quarter 2008;
9. The Financing/Start of Construction is scheduled for the 4th quarter 2008/1st quarter 2009;
10. The Commercial Operating Date is scheduled for 3rd quarter 2013.

Summary

Since the [redacted] offer from [redacted] was withdrawn, only the [redacted] offer of the [redacted] capacity was considered in any detail. Due to the permitting issues associated with new coal plants, there is increasing uncertainty about the ability to obtain permits for new units in a timely fashion. The recent activity of interveners in the permitting process for coal fired power plants indicates that there should be an assumed minimum of a 12 month delay in the COD of the [redacted] from that provided by [redacted] due to these issues.

The transmission improvements necessary for full deliverability status of the [redacted] to the MISO market have not been established. AmerenUE assumes that the increased project cost for transmission services will add approximately 6 percent to the project cost.

A 30 year levelized analysis of the [redacted] was performed based on the information provided. A discount rate of 8.8851 percent was used for net present value calculations. A weighted cost of capital of 10.1375 percent was used for the levelization of the [redacted]

All values provided by [redacted] were in 2007$ with the exception of the demand charge. Inflation was taken as 2.5 percent based on the [redacted] assumption. The demand charge was deflated to 2007$ using this average inflation amount. Allowance was made for transmission project capital costs by adding 6 percent of the demand charge to the demand charge provided by [redacted] Delivery costs will be additive to the levelized analysis.

Using the information provided and the assumptions shown on the attached analysis, the levelized analysis summarized below indicates that the [redacted] PPA has the levelized costs shown in Table 2 at a 90 percent capacity factor, which was the level at which the emissions were defined from the unit. The mid-range and high range demand charges were used in the analysis. The full summary is in 4CSR 240-22.040 Appendix R.

30 Yr. Levelized Cost Analysis

[redacted]

Emission Scenario	Mid Range Demand Charge ($/MWh)	High Range Demand Charge ($/MWh)
None	[redacted]	[redacted]
Business as usual	[redacted]	[redacted]
$15CO2	[redacted]	[redacted]

[redacted] has indicated that they believe the high range of demand charges includes all of the uncertainty associated with the project capital costs. The above analysis does not consider the cost of imputed debt on AmerenUE from use of a power purchase agreement.

Planning risks associated with th[redacted] offer include the inability to advance or delay the project based on AmerenUE's needs. Since this is a developer based project and AmerenUE is not taking the total output, then the plant will only be constructed when it is fully subscribed. This may be earlier or later than is optimal with AmerenUE's needs.

Another risk is the development of the necessary transmission improvements required to provide for full deliverability to the MISO system. These analyses are currently under way and will not be known for several months. The extent of improvements necessary and utilities involved may impact the construction time for the projects. A 1 percent increase in transmission investment would result in a 0.2 to 0.3 percent increase in project cost.

Transmission delivery risk for the project is not an issue once the project is deemed deliverable to MISO. The cost exposure to losses and congestion could be reduced by AmerenUE's use of transmission rights in the MISO market and the extent to which the loss and congestion exposure could be hedged by Ameren.

AmerenUE decided that evaluating the build greenfield advanced supercritical coal costs developed by B&V with full and partial ownership was representative of the [redacted] as well as the greenfield coal plant. If coal technology is selected as part of the preferred resource plan, AmerenUE will have further decisions wit [redacted] before determining the specific approach of building a plant versus a power purchase agreement.

4 CSR 240-22.040 (6)

For the utility's preferred resource plan selected pursuant to 4 CSR 240-22.070(7), the utility shall determine if additional future transmission facilities will be required to remedy any new generation-related transmission system inadequacies over the planning horizon. If any such facilities are determined to be required and, in the judgment of utility decision-makers, there is a risk of significant delays or cost increases due to problems in the siting or permitting of any required transmission facilities, this risk shall be analyzed pursuant to the requirements of 4 CSR 240-22.070(2).

AmerenUE periodically performs near-term and long-term studies of the transmission system to identify the need for additional facilities in the future. This effort includes evaluation of alternative developments to identify and subsequently implement the optimum portfolio of new transmission projects in the planning horizon.

Proposals by entities to connect new generation to transmission facilities under the purview of the Midwest ISO are handled by a series of activities. First, the entity proposing the addition of generation makes a formal request to the Midwest ISO and establishes a generation queue position. The queue position drives all study work and cost allocation for system upgrades, if needed. Proposed generation additions are generally studied in queue order.

The first step is for the Midwest ISO to convene an ad hoc group of stakeholders to discuss the proposed generation connection and to identify the required scope of the study work to evaluate the impact of the proposed connection. Possible impacts from other generation connection requests in the area are also considered. Other generation requests in the same area and having similar queue order may be studied together to determine an aggregate system impact.

The next step in the process is for Midwest ISO to coordinate the completion of a Feasibility Study. (This study, as well as the other studies in the process may be done by Ameren, a consultant hired by Midwest ISO, or the Midwest ISO staff.) The purpose of the

Feasibility Study is to make a rough determination of the likely impact of the proposed generation on the transmission system and a very rough cost of facilities or changes needed to alleviate any problems. Stakeholders are invited to comment on the results and request adjustments. If the results of the Feasibility Study are judged to be favorable by the entity proposing the generation addition, that entity may request the completion of a System Impact Study.

The System Impact Study is a more detailed analysis of the impact of the generation addition and includes the development of mitigation plans including better cost estimates. Study results are conveyed to stakeholders. If requested by the entity proposing the generation, the next step completed is a Facilities Study. This study determines the scope of work for the transmission upgrades, evaluates the competing alternatives (if there are any) and includes detailed cost and schedule estimates that would alleviate any connection and deliverability issues if the proposed generation is connected to the transmission system. Risks associated with building facilities in known problem areas that could impact cost and schedule would be identified in these studies.

The cost for the new facilities may be the direct responsibility of the entity developing the generation or may be cost-shared with transmission owners, depending on the nature of the facilities and the impact on the system. Cost-sharing mechanisms are outlined in various Midwest ISO tariffs. The risks associated with increased costs due to permitting delays or material escalation would be somewhat reduced as those participating in the cost sharing would be responsible for the actual costs and not the estimated costs of the project.

Assuming the satisfactory completion of the studies and agreement with their results, Interconnection Agreements would be negotiated between the Midwest ISO, the transmission owner, and the generation developer and signed and filed with FERC. These agreements would compel the transmission owner to start the engineering and permitting processes to build the identified transmission facilities to connect and deliver power from the new generator to the load in the Midwest ISO. The agreements also contain language that address the risks of significant delays or cost increases due to problems in siting or permitting.

4 CSR 240-22.040 (7)

The utility shall assess the age, condition and efficiency level of existing transmission and distribution facilities, and shall analyze the feasibility and cost-effectiveness of transmission and distribution system loss-reduction measures as a supply-side resource. This provision shall not be construed to require a detailed line-by-line analysis of the transmission and distribution system, but is intended to require the utility to identify and analyze opportunities for efficiency improvements in a manner that is consistent with the analysis of other supply-side resource options...

AmerenUE has established processes to identify transmission assets with anticipated or demonstrated deficiencies related to age and condition. The condition of substation equipment is assessed periodically via the Transmission Asset Management process. Replacement or refurbishment is scheduled as needed. Information on lines identified for significant maintenance (e.g., replacement of conductor or structures) is provided to Electric Planning 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. Electric Planning has established a process to provide Corporate Planning information on an annual basis regarding the likely loss reduction associated with lines being replaced or rebuilt due to age or condition. It is expected those loss reductions will be included as a supply-side resource.

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

a) Circuit and Device Inspections

   Circuits and Devices are inspected to protect public and worker safety and to proactively address problems that might impact system reliability. The program includes inspection of all sub-transmission and distribution circuits having voltages in the range of 4kV to 69kV, as well as the poles, hardware and equipment on those circuits. The program also addresses the follow-up actions required to address deficiencies found during the inspections. Inspections are scheduled on an alternating basis to ensure each circuit has a visual inspection cycle of no more than 4 years for urban circuits or 6 years for rural circuits. Inspection program changes will be incorporated, as required, to comply with final adoption of Proposed 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, AmerenUE uses higher efficiency transformers. In addition, the Circuit and Device Inspection Program includes annual inspections of all line capacitors. Any cells found to be inoperable are repaired or replaced, thus enabling the proper power factor correction function.

b) Multiple Device Interruptions

Devices experiencing three or more avoidable interruptions in a 12-month period are designated for an engineering review. Corrective actions might include spot tree trimming, protective device additions, interrupting device coordination reviews, or other remedies.

c) URD Replacements

Individual sections of single phase or three phase direct buried cable are replaced after; four failures in a lifetime, or three failures in a lifetime provided two of them occur within a twelve month period.

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 after; an average failure rate of 0.6 failures/section is observed within a three-year period, or a total of six failures occur among all the cable sections within a three-year period.

These latter criteria apply only when there are at least three cable sections in the lateral and the failures are distributed among at least one-third of the cable sections in the lateral. When a lateral meets these criteria, an engineering representative in the associated division will study its performance in more detail (as well as the performance of the lateral on the other side of the normal open if it's looped) in order to make a final determination as to how much cable (if any) will be replaced.

Cables that have failed but do not satisfy any of the criteria above may also be replaced based on division judgment. In these cases the engineer or other division personnel will make the appropriate field observations or perform the necessary investigations to build a case that supports a cable replacement decision.

d) Substation Maintenance Strategy

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

e) Distribution Component Life-Cycle Analysis

AmerenUE is currently evaluating a life cycle analysis tool. Its purposes are to establish credible and defensible asset life cycle estimates, determine future spending requirements for all asset classes, and support regulatory and management efforts to fund the replacement and cost recovery of aging delivery infrastructure. As equipment is replaced and the system is developed, an emphasis is placed on efficiency and reduction of losses.

f) Conversion of Dusk-to-Dawn Lighting

AmerenUE standard lighting is high-pressure sodium with metal halide as an option for color sensitive applications. Mercury vapor, fluorescent and incandescent lamps are obsolete types and are replaced with high-pressure sodium luminaries as they fail. AmerenUE continually monitors development of more efficient lighting technology for trial applications.

AmerenUE assesses system capacity, efficiency and losses via seasonal distribution system planning studies.

a) Annual Distribution System Load Analysis and System Planning Process

AmerenUE records summer and winter peak load conditions (power, power factor, phase balance and voltage levels) at bulk and distribution substations. Peak load data are temperature-corrected to represent 1-in-10 year maximum values. Temperature correction multipliers are derived from statistical analysis of historic load data for several types of area load characteristics. Power flow analyses are then performed using the temperature corrected distribution substation loads as input data. Calculated bulk substation loading is compared with the temperature corrected measured values to evaluate what, if any, diversity factors are applicable at each bulk substation.

An integral part of the Distribution System Load Analysis Process is the establishment of equipment ratings and/or loading limits. AmerenUE evaluates transformer and conductor losses as part of the methodology used in establishing distribution equipment ratings 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. After verifying the validity of the system model, AmerenUE performs seasonal planning studies for winter and summer peak conditions. Worst-case single-contingency failure scenarios are evaluated for all bulk subtransmission substations, 34kV and 69kV subtransmission feeders, distribution substations, and distribution feeders. These studies assist in evaluating system limitations requiring upgrades necessary to maintain adequate system capacity. 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 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.

b) 2006 System Loss Study

During 2006, AmerenUE evaluated its overall electric delivery system losses. The results of this study were derived from a comprehensive analysis of the AmerenUE-MO electric system for the calendar year 2003. The results of this study are being employed in system planning activities.

c) Distribution System Engineering Analysis

- Transformer Load Management System

  This system provides the basis for the company's distribution circuit analysis and trouble analysis systems. By relating customers to the distribution transformer that serves them, the Transformer Load Management (TLM) system allows AmerenUE to predict transformer peak demand and KVA from the customer's total monthly energy usage. These predicted transformer loadings are utilized in the distribution circuit analysis system (see the next section regarding circuit analysis and DEW). The TLM system also allows monitoring of individual transformer summer and winter loadings to assist in providing reliable service to customers. Additionally, the company uses automated meter reading (AMR) technology to capture hourly meter demands during peak load periods to confirm and support the predicted loads calculated by TLM system. This AMR technology/process, referred to as System Load Snapshot, is executed when requested during selected system peak demand days in the summer and winter.

- Distribution Engineering Workstation System

  AmerenUE utilizes EPRI's Distribution Engineering Workstation (DEW) for distribution circuit analysis. Models of the distribution circuits are utilized in

DEW to perform analysis in order to ensure reliable, safe, and efficient operation of the distribution system. DEW is used to perform the following types of analyses at AmerenUE: Load Estimation, Power Flow, Protective Device Coordination, Fault Current, Voltage Flicker, Phase Balancing, and Capacitor Placement. DEW 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

- PSS/E System

  AmerenUE utilizes Siemens PTI's PSS/E software to evaluate Power Flow, Voltage Flicker and Capacitor Placement within the subtransmission system. Circuit models are utilized in PSS/E to perform these analyses in order to ensure reliable, safe, and efficient operation of the distribution 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.

- ASPEN System

  AmerenUE utilizes ASPEN, Inc. software to evaluate Fault Current and Protective Device Coordination within the subtransmission system. Circuit models are utilized in ASPEN to perform these analyses in order to ensure reliable and safe operation of the distribution system. 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.

- SCADA System

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

d) Transformer Replacement for Loss Reduction

AmerenUE 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.

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

a) Project Evaluation

Potential projects are typically identified by system operating personnel, operating division engineering staff, and distribution system planning engineers. All bulk substation, 34kV & 69kV line, and distribution substation projects are reviewed by the Distribution System Planning Department, while operating division engineers evaluate distribution system projects for 12kV and lower voltage levels.

All projects are compared on a level playing field, using an Integrated Spending Prioritization (ISP) Tool. ISP evaluates several aspects (financial payback, customer satisfaction, safety, reliability, financial risk, technical risk, etc.) of a potential project when establishing funding priorities. One part of this evaluation is based on a Risk Based Prioritization method utilizing a Service Availability Cost Factor (SACF). SACF is a calculated index that facilitates ranking projects on a common cost-benefit basis. In its simplest form, SACF represents the cost per unit risk where risk is measured as the customer load x hours of outage. It is often referred to as the cost per kVA-hr saved which represents the cost to save or avoid an outage to 1 unit of customer load (kVA) for one hour. By giving preference to projects with the lowest SACF scores, AmerenUE insures that system reliability will be enhanced as fully as possible by prioritized spending of the available capital funding.

System improvement options typically include the analysis of incremental system losses. For example, the addition of a new Farmington Substation was recommended instead of adding another unit to the Esther Sub, due largely to a reduction of line loss.

b) Loss-Evaluated Transformer Purchasing

AmerenUE purchases distribution transformers on a loss-evaluated basis, including first cost plus the evaluated cost of both no-load and load losses, capitalized over a 30 year life.

Future D.O.E. efficiency regulations may revise this methodology, but AmerenUE's current purchasing practices result in the lowest full-life total owning cost for medium and large power transformers.

c) System Power Factor

AmerenUE frequently executes 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, less current flows through the system and there is less power lost (I^2R losses) to heating of cables, bus bars, transformers, etc. These devices will run cooler and last longer too.

d) Typical Projects which Affect System Loss Reductions

- AmerenUE 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 138kV-fed distribution substations.
- When Division engineering staff review 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.

e) Distributed Generation Projects (AmerenUE owned and dispatched)

AmerenUE does have some interest in distributed generation to delay necessary distribution system expansion projects. Potential projects can be analyzed on a case-by-case basis; however, the scope of potential candidates tends to be small. Furthermore, there is a broad range of additional considerations that do not favor installations, including:

- System expansion projects usually provide significantly improved benefits that the addition of distributed generation would not provide. As an example, a second distribution feeder or unit at a substation provides contingency backup.
- The citing complexities, including noise and other required permitting take additional time and resources.
- There are a range of operational complexities, including fuel availability, testing, how to address failures, and new skill sets for employees that need to be overcome.

f) Customer Generation Projects (behind the meter)

Using Customer Generation for distribution system reliability is not in the scope of AmerenUE's electrical distribution system contribution to the IRP. For Renewable energy sources and energy technologies that substitute for electricity at the point of use, see 4 CSR 240-22.050(1)(D). However, the following comments are offered for consistency with the preceding information regarding distributed generation:

- Customer generation reduces the overall customer demand by supplying power locally (behind the meter) and it is not envisioned to include backfeed by customers to the distribution system.

- Unless there is an agreement whereby AmerenUE is authorized to dispatch the customer generation, there can be no distribution system benefit because AmerenUE could not count on the generation.
- Consequently, AmerenUE does not count non-dispatchable (behind the meter) customer generation to reduce peak demand when performing load analysis and system improvement justifications.