Public

Integrated Resource Plan

4 CSR 240-22.070

Risk Analysis and Strategy Selection

February 2008

4 CSR 240-22.070 (1)

The utility shall use the methods of formal decision analysis to assess the impacts of critical uncertain factors on the expected performance of each of the alternative resource plans developed pursuant to 4 CSR 240-22.060 (3), to analyze the risks associated with alternative resource plans, to quantify the value of better information concerning the critical uncertain factors and to explicitly state and document the subjective probabilities that utility decision-makers assign to each of these uncertain factors. This assessment shall include a probability tree representation of uncertainties associated with each alternative resource plan.

The scenario tree presented in the response to section 4 CSR 240-22.040 (8) (D) illustrates the critical uncertain factors that produced the nine sets of integrated projections of key IRP inputs (*i.e.*, scenarios) to be used in the strategy selection phase. The responses to sections 4 CSR 240-22.030 (7), 4 CSR 240-22.040 (2) (B) 1- 3, and 4 CSR 240-22.040 (8) (A) clarify how the load growth, CO_2 policy, and natural gas price branches of the probability tree were developed, and how AmerenUE assigned subjective probabilities to each of these scenarios. The final probability tree, including the critical independent uncertainties and the subjective probabilities assigned to them, appears in the response to section 4 CSR 240-22.070 (5). The response to section 4 CSR 240-22.070 (8) details how AmerenUE derived the expected value of perfect information (EVPI) for each of the critical scenario and independent uncertainties. Finally, the response to section 4 CSR 240-22.070 (5) (B) presents the cumulative distribution function (cdf) of the difference from the best plan, in terms of the present value of revenue requirements (PVRR), as well as deciles of this cumulative probability for each of the top 18 alternative resource plans subjected to risk analysis. From this analysis, a preferred alternative resource plan emerged, the NUC1600-Agg-LowNoWind option. 4 CSR 240-22.070 Appendix A introduces a concept called risk preference, and reinforces the preferred status of the NUC1600-Agg-LowNoWind plan within all reasonable levels of risk aversion.

4 CSR 240-22.070 (2)

Before developing a detailed probability tree analysis of each resource plan, AmerenUE will conduct a preliminary sensitivity analysis to identify the uncertain factors that are critical to the performance of the resource plan. This analysis shall assess at least the following uncertain factors:

(A) The range of future load growth represented by the low-case and high-case load forecasts;
(C) Future changes in environmental laws, regulations, or standards;
(D) Relative fuel prices;
(H) Sulfur dioxide emission allowance prices;

The preliminary sensitivity analysis for uncertain factors was segmented into two steps: joint sensitivity analysis (or Step 1: Scenarios) and independent sensitivity analysis (or Step 2). The analysis process was fully defined in AmerenUE's Waiver Request Related to Risk Analysis and Strategy Selection which was filed with the MPSC on April 19th, 2007. The MPSC approved the waiver requests on May 10, 2007. A preliminary screening analysis for uncertain factors described in (A), (C), (D), and (H) was performed as a part of the joint sensitivity analysis (or Step 1: Scenarios).

(A) The range of future load growth represented by the low-case and high-case load forecasts;

The response to section 4 CSR 240-22.030 (7) delineates the load growth cases modeled as part of the integrated MRN-NEEM scenarios comprising the probability tree. AmerenUE deemed that the "transformed demand" scenario, in which accelerated rates of energy efficiency improvement spur substantial reductions in utility demand, and the "base load" case fully encompassed the range of uncertainty in Eastern Missouri load profiles through 2026. Both sensitivity analysis and full-scale MRN-NEEM modeling confirmed that altering load growth assumptions materially affected the key parameters (electricity prices, allowance prices, *etc.*) upon which resource plans are evaluated.

(C) Future changes in environmental laws, regulations, or standards;

Both CRA International and AmerenUE management initially judged CO_2 policy uncertainty as one of the most influential drivers in the resource plan selection phase, and preliminary sensitivity analysis proved this to be true. Thus, AmerenUE appropriately represented this uncertainty through four distinct cases in the probability tree, explained in the responses to sections 4 CSR 240-22.040 (2) (B) 1, 4 CSR 240-22.040 (2) (B) 2, and 4 CSR 240-22.040 (2) (B) 3.

(D) Relative fuel prices;

As described in the natural gas price forecast component of the response to section 4 CSR 240-22.040 (8) (A), AmerenUE developed a base natural gas price scenario and a high natural gas price scenario to envelop the uncertainty in natural gas prices. Their inclusion in the probability tree indicates that they are indeed critical to the performance of candidate plans. In contrast to natural gas prices, coal prices are endogenously determined in the NEEM model, as given in the coal price forecast component of the response to the same section. Prior to scenario modeling, CRA also assessed the sensitivity of electricity prices in Eastern Missouri to variations in nuclear fuel prices, capital costs for new nuclear generators, and nuclear penetration limits. In particular, CRA appraised the effects of (1) increasing nuclear fuel prices six-fold, (2) increasing new nuclear capital costs by 150%, and (3) raising the nuclear penetration rates threefold, in both BAU and high CO_2 price contexts. The spread in Eastern Missouri electricity prices resulting from the various combinations of nuclear policy assumptions was not significant enough to merit inclusion in the probability tree.

(H) Sulfur dioxide emission allowance prices;

SO_2 allowance prices are endogenously formulated in the MRN-NEEM model, in accordance with the methodology outlined in the response to section 4 CSR 240-22.040 (2) (B) 4.

(B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital;;

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities;

(F) Construction costs and schedules for new generation and transmission facilities;;

(G) Purchased power availability, terms and cost;;

(I) Fixed operation and maintenance costs for existing generation facilities;

(J) Equivalent or full- and partial-forced outage rates for new and existing generation facilities;

(K) Future load impacts of demand-side programs; and;

(L) Utility marketing and delivery costs for demand-side programs.;

Independent Uncertain Factors Sensitivity Analysis Overview

The items listed in sections (B), (E), (F), (G), (I), (J), (K), and (l) below plus one additional independent uncertain factor, with and without Renewable Production Tax Credits, were analyzed in the Independent Uncertain Factor Sensitivity Analysis. This discussion is divided into 3 sections: Data, Modeling, and Analysis.

Some of the items listed below were determined to be dependent uncertain factors and thus were reviewed by CRA and included in their development of the nine (9) scenarios. The remaining items, (B), (D – Only Nuclear Fuel), (E), (F), (G), (I), (J), (K) and (L) were all included as individual independent uncertain factors and are listed here as:

1) Capital Costs
2) Interest Rates
3) Equivalent Forced Outage Rate
4) Variable O&M
5) Fixed O&M
6) Nuclear PTC
7) Renewable PTC
8) Nuclear Fuel Costs
9) Off-system sales
10) Demand-Side Resources
11) Decommissioning Costs

Data:

Data for a range of potential values of each of the eleven uncertain factors, and their associated probabilities, was provided by a variety of expert sources.

Some representative examples of this data, in this case provided by the engineering firm Black & Veatch, are shown in the tables below.

Parameter					
Capital Cost					
Fossil					
Deviation	30	15	0	-10	-20
Probability	5%	25%	40%	25%	5%
Renewable					
Deviation	30	15	0	-10	-20
Probability	5%	25%	40%	25%	5%

Variable O&M Cost					
850 MW PC					
Range	-60%	Base	40%	80%	
Probability	15%	50%	25%	10%	

EFORd			
850 MW PC			
Range	4	6	10
Probability	25%	50%	25%

There is a variety of how many values are provided for any particular uncertain factor. Sometimes there are 5 different potential values and associated probabilities, sometimes 4, sometimes 3. In addition, there are a wide variety of probabilities for the lowest value and for the highest value: among these 3 examples probabilities for the lowest value were either 5%, 15%, or 25%, and probabilities for the highest value were either 5%, 10%, or 25%.

Thus a user could not simply use the given lowest value as the “Low” since there would be a different probability associated with the probability of “Low” for each uncertain factor. Similarly, a user could not simply use the given highest value as the “High” since there would be a different probability associated with the probability of “High” for each uncertain factor.

To have a common meaning for the probability of Low/Base/High, the probability distributions implied by this variety of data were created, and a common definition of Low/Base/High was used to pull values from those implied probability distributions. This process did not depend on how many values were provided by experts for each uncertain factor, and it overcame the problem of having varying levels of probabilities associated with varying numbers of observations for various uncertain factors.

Given the implied probability distribution curve for any uncertain factor, the value at its 25th percentile was used for the "Low" case, the value at its 50th percentile was used for the "Base" case, and the value at its 75th percentile was used for the "High" case. Recall the meaning and use of percentiles:

- A value at the 25th percentile of a probability distribution means that there is a 25% chance that this value (or a lower value) will occur, looking leftward toward lower values on the curve. Looking the other direction from the 25th percentile (rightward, towards higher values on the curve), there is a 75% chance that higher values than this value will occur.
- A value at the 50th percentile of a probability distribution means that there is a 50% chance that this value (or a lower value) will occur, looking leftward toward lower values on the curve. Looking the other direction from the 50th percentile (rightward, towards higher values on the curve), there is a 50% chance that higher values than this value will occur.
- A value at the 75th percentile of a probability distribution means that there is a 75% chance that this value (or a lower value) will occur, looking leftward toward lower values on the curve. Looking the other direction from the 75th percentile (rightward, towards higher values on the curve), there is a 25% chance that higher values than this value will occur.

Use of 25th percentile for "Low" and 75th percentile for "High" was true for all uncertain factors with one exception. That exception was the Capital Cost uncertain factor, in which case the 10th percentile was used for the "Low" case instead of the 25th percentile, and the 90th percentile was used for the "High" case instead of the 75th percentile. This change was made to reflect the expected higher sensitivity to Capital Cost variation.

> Oracle's Crystal Ball is the leading spreadsheet-based software suite for predictive modeling, forecasting, simulation, and optimization. Used by 85 percent of the Fortune 500, Crystal Ball gives you unparalleled insight into the critical factors affecting risk, and calculates the likelihood that you will reach your objectives. With Crystal Ball, you will make the right tactical decisions to move you toward your strategic goals and gain a competitive edge under even the most uncertain market conditions.
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The range of likely values and their associated probabilities was converted into the implied probability distribution curves by using the "probability curve fitting" capability of "Crystal Ball" software from Oracle Corporation. This process is shown by using one of the three example datasets shown above, the "Variable O&M Cost" (VOM) data for "850 MW PC."

Variable O&M Cost					
850 MW PC					
Range	-60%	Base	40%	80%	
Probability	15%	50%	25%	10%	

The VOM uncertain factor (and many other uncertain factors) will be used as a "multiplier factor" in the subsequent modeling steps, so the data in the first row, which is percent change data, is converted to an equivalent "multiplier factor" data by adding 100% to each percent change value.

Variable O&M Cost				
850 MW PC				
Range	-60%	Base	40%	80%
%Change expressed as Multiplier	40%	100%	140%	180%
Probability	15%	50%	25%	10%

For example, the 80% percent change entry in the 4th column of data in the table then becomes a 180% "multiplier factor." These two are equivalent, since an 80% percent change applied to a value of 1000 results in 1800, while a 180% multiplier factor applied to the same value of 1000 results in the same 1800. These equivalents are inserted into this table, and are highlighted by a yellow background.

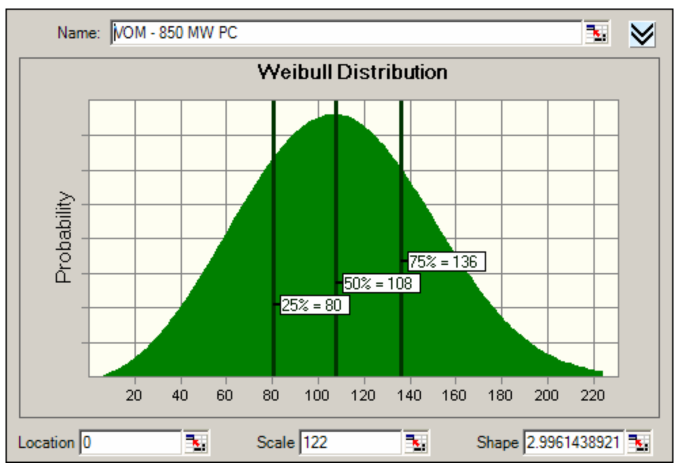
Crystal Ball software needs a minimum of 15 observations to fit a probability distribution, and none of the uncertain factors came with anywhere close to 15 observations. However, the probability curve fitting can still occur by using multiple occurrences of the given values so that this minimum is met or exceeded, in appropriate quantities, reflecting the given probabilities of those values.

In the case of "VOM 850 MW PC," if 20 total observations are used to develop the implied probability distribution

- 15% of the 20 observations (3 observations) would have a value of "40%"
- 50% of the 20 observations (10 observations) would have a value of "100%"
- 25% of the 20 observations (5 observations) would have a value of "140%"
- 10% of the 20 observations (2 observations) would have a value of "180%

	#	value
1	1	40
2	2	40
3	3	40
4	1	100
5	2	100
6	3	100
7	4	100
8	5	100
9	6	100
10	7	100
11	8	100
12	9	100
13	10	100
14	1	140
15	2	140
16	3	140
17	4	140
18	5	140
19	1	180
20	2	180

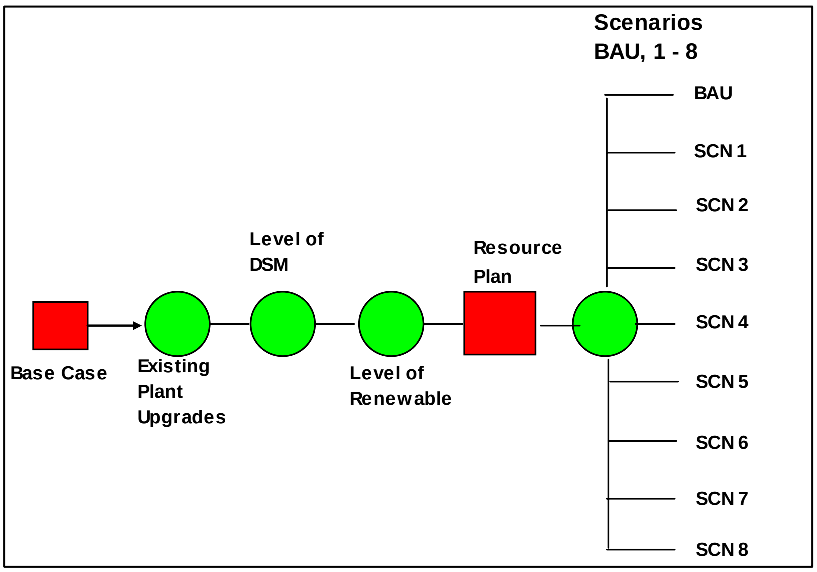
The probability distribution implied by this data for the "VOM 850 MW PC" uncertain factor is shown in the nearby chart. On the chart is shown the values at the 25th, 50th, and 75th percentiles. Thus the Low, Base and High values for the "multiplier factor" for "VOM 850 MW PC" would be:



- 80% for the "Low" case (using the value at the 25th percentile)
- 108% for the "Base" case (using the value at the 50th percentile)
- 136% for the "High" case (using the value at the 75th percentile)

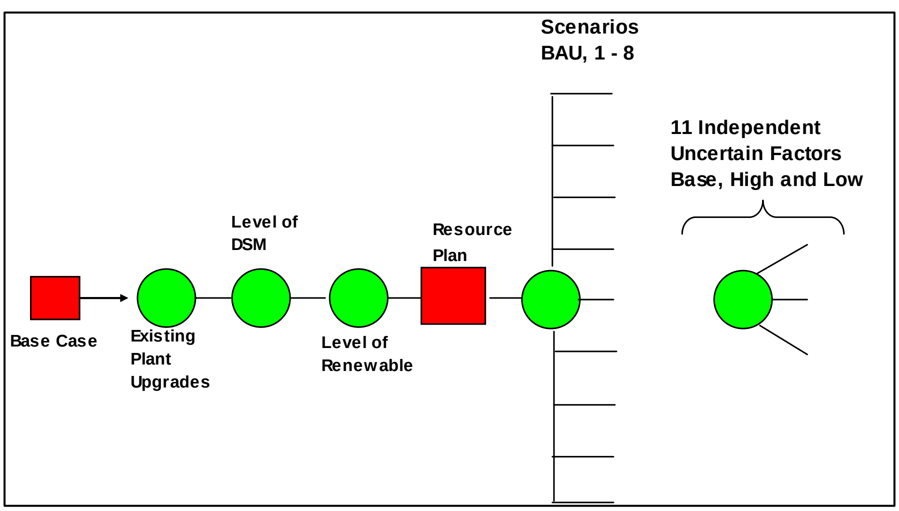
Modeling Independent Critical Uncertain Factors

An illustration of the frame work for modeling the critical uncertain factors is shown in a decision tree below starting with an example of a basic resource plan:



Generic example of a study created using one resource plan.

Studies were then built with each of the top 18 resource plans and then the 11 independent uncertain factor nodes were added to the tree. An illustration of the frame work for modeling each resource plan with the 11 uncertain factors is shown below:



Generic example of a study used to test the 11 Independent Uncertain Factors.

Analysis of Critical Uncertain Factors

Determination of which independent uncertain factors were critical uncertain factors was accomplished by analyzing the change in two metrics when using 3 value levels (Low/Base/High) for each of the 11 independent uncertain factors, for the top 18 alternative resource plans, in 9 scenarios, a total of 5,346 endpoints. The change was calculated by comparing the difference between using a High value versus a Base value, and when using a Low value versus a Base value. The two metrics were

- Change in present value of revenue requirement (PVRR)
- Change in rank on PVRR

The analysis began by finding the best (lowest) PVRR for any of the 18 plans for each scenario, given a Base value for each uncertain factor. This is shown in the first nearby table, with the abbreviations used here and later in this section explained in the second nearby table. The value for the best PVRR for each scenario is the same regardless of which independent uncertain factor is used, when a base value for each independent uncertain factor is used.

Minimum of PVRR		ScenarioNum								
Level	Indep Unc.	0	1	2	3	4	5	6	7	8
Base	Cap. Costs	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	Decomm	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	DSM	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	EFOR	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	FOM	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	Int. Rates	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	NPTC	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	NRPTC	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	Nuc Fuel	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	OSS	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
	VOM	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695

Abbreviation	Full name
Cap. Costs	Capital Costs
Decomm	Decommissioning costs
DSM	Demand-side resources
EFOR	Equivalent forced outage rate
FOM	Fixed O&M
Int. Rates	Interest rates
NPTC	Nuclear production tax credit
NRPTC	No renewable production tax credit
Nuc Fuel	Nuclear fuel
OSS	Off-system sales
VOM	Variable O&M

Tables of PVRR results when using Low, Base, and High values for the independent uncertain factors were then created. Each of the 1,782 endpoints in each of these 3 tables (5,346 total endpoints) was compared to the appropriate best PVRR. This was done using each endpoint's scenario number to make the comparison to the appropriate best PVRR. The differences versus best PVRR by scenario number were multiplied by the scenario probabilities, and then totaled for an expected value of difference versus best PVRR.

This process of assembling the PVRRs, calculating and summing the differences is shown in a partial example in two tables below. In the first table, the PVRRs when using Base value levels for the top 18 resource plans are shown by scenario for Capital Costs and partially for Decommissioning Costs, with the scenario minimum PVRR (best) shown in the blue-highlighted row above it.

Level	IndepUncert	Plan	B-Scen_0	B-Scen_1	B-Scen_2	B-Scen_3	B-Scen_4	B-Scen_5	B-Scen_6	B-Scen_7	B-Scen_8
		Scenario Min (best) --->	34,595	37,509	39,126	38,265	39,609	36,826	36,557	34,968	35,695
B	Cap. Costs	Coal425W/OCCS-Agg-Moderate	34,990	39,110	40,351	39,446	40,722	37,297	36,838	35,439	35,788
B	Cap. Costs	Coal425W/OCCS-Agg-no	34,595	39,473	40,572	39,654	40,886	37,194	36,596	36,408	36,458
B	Cap. Costs	Coal850W/OCCS-Agg-Moderate	34,860	38,923	40,282	39,282	40,624	37,176	36,780	35,439	35,788
B	Cap. Costs	Combine Cycle-Agg-Moderate	34,935	39,086	40,229	39,370	40,612	37,242	36,727	35,439	35,788
B	Cap. Costs	NUC1200-Agg-High	35,823	37,768	39,410	38,601	39,947	37,302	37,255	34,968	36,116
B	Cap. Costs	NUC1200-Agg-LowW/Wind	35,054	38,343	39,719	38,807	40,150	37,067	36,750	36,573	37,182
B	Cap. Costs	NUC1200-Agg-Moderate	35,187	37,862	39,371	38,500	39,838	36,964	36,752	35,431	36,308
B	Cap. Costs	NUC1200-Agg-no	34,970	38,466	39,804	38,855	40,198	37,068	36,702	36,495	37,060
B	Cap. Costs	NUC1200-Agg-Wind	35,653	38,062	39,624	38,811	40,149	37,318	37,181	35,608	36,582
B	Cap. Costs	NUC1600-Agg-High	36,012	37,509	39,236	38,507	39,857	37,310	37,373	35,134	36,458
B	Cap. Costs	NUC1600-Agg-LowW/Wind	35,210	37,974	39,480	38,600	39,933	37,028	36,816	36,619	37,428
B	Cap. Costs	NUC1600-Agg-Moderate	35,330	37,525	39,126	38,265	39,609	36,914	36,817	35,471	36,501
B	Cap. Costs	NUC1600-Agg-no	35,119	38,090	39,559	38,645	39,976	37,021	36,761	36,573	37,303
B	Cap. Costs	NUC1600-Agg-Wind	35,821	37,746	39,402	38,609	39,953	37,292	37,270	35,623	36,764
B	Cap. Costs	Pumped Storage-Agg-Moderate	34,928	39,072	40,250	39,217	40,581	37,242	36,735	35,423	35,821
B	Cap. Costs	Simple Cycle-Agg-High	35,647	38,988	40,305	39,508	40,730	37,593	37,268	34,983	35,695
B	Cap. Costs	NUC1600-Agg-LowNoWind	35,083	37,658	39,197	38,286	39,625	36,826	36,648	36,046	36,929
B	Cap. Costs	Combine Cycle-Agg-LowNoWind	34,704	39,248	40,301	39,419	40,672	37,127	36,557	35,980	36,162
B	Decomm	Coal425W/OCCS-Agg-Moderate	34,990	39,110	40,351	39,446	40,722	37,297	36,838	35,439	35,788
B	Decomm	Coal425W/OCCS-Agg-no	34,595	39,473	40,572	39,654	40,886	37,194	36,596	36,408	36,458
B	Decomm	Coal850W/OCCS-Agg-Moderate	34,860	38,923	40,282	39,282	40,624	37,176	36,780	35,439	35,788
B	Decomm	Combine Cycle-Agg-Moderate	34,935	39,086	40,229	39,370	40,612	37,242	36,727	35,439	35,788

In the second table, the differences versus scenario best PVRR are shown, after being multiplied by the scenario probabilities which are found in the green-highlighted row. These are totaled to create an expected value of difference versus best PVRR, and the final column shows a ranking of the 18 plans on that expected value.

Level	IndepUncert	Plan	B-Part_0	B-Part_1	B-Part_2	B-Part_3	B-Part_4	B-Part_5	B-Part_6	B-Part_7	B-Part_8	B-DiffTotal	RankOnB-DiffTotal
			0.50%	2.30%	30.55%	2.30%	30.55%	10.90%	10.90%	6.00%	6.00%	100.00%	<--Scen Wts
B	Cap. Costs	Coal425W/OCCS-Agg-Moderate	2	37	374	27	340	51	31	28	6	896	16
B	Cap. Costs	Coal425W/OCCS-Agg-no	0	45	442	32	390	40	4	86	46	1,085	18
B	Cap. Costs	Coal850W/OCCS-Agg-Moderate	1	33	353	23	310	38	24	28	6	817	14
B	Cap. Costs	Combine Cycle-Agg-Moderate	2	36	337	25	306	45	18	28	6	804	13
B	Cap. Costs	NUC1200-Agg-High	6	6	87	8	103	52	76	0	25	363	5
B	Cap. Costs	NUC1200-Agg-LowW/Wind	2	19	181	12	165	26	21	96	89	613	10
B	Cap. Costs	NUC1200-Agg-Moderate	3	8	75	5	70	15	21	28	37	262	3
B	Cap. Costs	NUC1200-Agg-no	2	22	207	14	180	26	16	92	82	640	11
B	Cap. Costs	NUC1200-Agg-Wind	5	13	152	13	165	54	68	38	53	561	9
B	Cap. Costs	NUC1600-Agg-High	7	0	33	6	76	53	89	10	46	319	4
B	Cap. Costs	NUC1600-Agg-LowW/Wind	3	11	108	8	99	22	28	99	104	482	7
B	Cap. Costs	NUC1600-Agg-Moderate	4	0	0	0	0	10	28	30	48	120	1
B	Cap. Costs	NUC1600-Agg-no	3	13	132	9	112	21	22	96	96	505	8
B	Cap. Costs	NUC1600-Agg-Wind	6	5	84	8	105	51	78	39	64	441	6
B	Cap. Costs	Pumped Storage-Agg-Moderate	2	36	343	22	297	45	19	27	8	799	12
B	Cap. Costs	Simple Cycle-Agg-High	5	34	360	29	342	84	77	1	0	932	17
B	Cap. Costs	NUC1600-Agg-LowNoWind	2	3	21	0	5	0	10	65	74	181	2
B	Cap. Costs	Combine Cycle-Agg-LowNoWind	1	40	359	27	325	33	0	61	28	872	15
B	Decomm	Coal425W/OCCS-Agg-Moderate	2	37	374	27	340	51	31	28	6	896	16
B	Decomm	Coal425W/OCCS-Agg-no	0	45	442	32	390	40	4	86	46	1,085	18
B	Decomm	Coal850W/OCCS-Agg-Moderate	1	33	353	23	310	38	24	28	6	817	14
B	Decomm	Combine Cycle-Agg-Moderate	2	36	337	25	306	45	18	28	6	804	13

A table of expected value of differences versus best PVRR when using Base values was created as a benchmark to use against a table of differences when using Low values, and when using High values.

The table of expected value of differences versus best PVRR when using Base values, the benchmark.

Sum of B-DiffTotal	Indep Uncert										
PlanName	Cap. Costs	Decomm	DSM	EFOR	FOM	Int. Rates	NPTC	NRPTC	Nuc Fuel	OSS	VOM
Coal425W/OCCS-Agg-Moderate	896	896	896	896	896	896	896	896	896	896	896
Coal425W/OCCS-Agg-no	1,085	1,085	1,085	1,085	1,085	1,085	1,085	1,085	1,085	1,085	1,085
Coal850W/OCCS-Agg-Moderate	817	817	817	817	817	817	817	817	817	817	817
Combine Cycle-Agg-LowNoWind	872	872	872	872	872	872	872	872	872	872	872
Combine Cycle-Agg-Moderate	804	804	804	804	804	804	804	804	804	804	804
NUC1200-Agg-High	363	363	363	363	363	363	363	363	363	363	363
NUC1200-Agg-LowW/Wind	613	580	613	613	613	613	613	613	613	613	613
NUC1200-Agg-Moderate	262	261	262	262	262	262	262	262	262	262	262
NUC1200-Agg-no	640	639	640	640	640	640	640	640	640	640	640
NUC1200-Agg-Wind	561	560	561	561	561	561	561	561	561	561	561
NUC1600-Agg-High	319	319	319	319	319	319	319	319	319	319	319
NUC1600-Agg-LowNoWind	181	181	181	181	181	181	181	181	181	181	181
NUC1600-Agg-LowW/Wind	482	447	482	482	482	482	482	482	482	482	482
NUC1600-Agg-Moderate	120	124	120	120	120	120	120	120	120	120	120
NUC1600-Agg-no	505	505	505	505	505	505	505	505	505	505	505
NUC1600-Agg-Wind	441	441	441	441	441	441	441	441	441	441	441
Pumped Storage-Agg-Moderate	799	799	799	799	799	799	799	799	799	799	799
Simple Cycle-Agg-High	932	932	932	932	932	932	932	932	932	932	932

The table of expected value of differences versus best PVRR when using High values.

Sum of H-DiffTotal	Indep Uncert										
PlanName	Cap. Costs	Decomm	DSM	EFOR	FOM	Int. Rates	NPTC	NRPTC	Nuc Fuel	OSS	VOM
Coal425W/OCCS-Agg-Moderate	1,421	896	816	1,464	928	1,824	896	896	896	896	916
Coal425W/OCCS-Agg-no	1,363	1,085	1,001	1,615	1,093	1,956	1,085	1,085	1,085	1,085	1,070
Coal850W/OCCS-Agg-Moderate	1,392	817	742	1,390	849	1,772	817	817	817	817	853
Combine Cycle-Agg-LowNoWind	1,187	872	793	1,399	887	1,732	872	872	872	872	830
Combine Cycle-Agg-Moderate	1,254	804	719	1,368	834	1,707	804	804	804	804	815
NUC1200-Agg-High	1,502	377	259	983	439	1,539	324	363	404	363	418
NUC1200-Agg-LowW/Wind	1,608	594	527	1,171	665	1,704	574	613	654	613	608
NUC1200-Agg-Moderate	1,156	276	173	839	315	1,391	223	262	303	262	292
NUC1200-Agg-no	1,324	654	559	1,179	668	1,707	601	640	681	640	635
NUC1200-Agg-Wind	1,736	575	470	1,197	623	1,738	521	561	602	561	559
NUC1600-Agg-High	1,669	338	221	953	403	1,605	267	319	374	319	376
NUC1600-Agg-LowNoWind	1,040	200	103	725	225	1,358	129	181	236	181	222
NUC1600-Agg-LowW/Wind	1,628	466	395	1,044	541	1,701	429	482	537	482	482
NUC1600-Agg-Moderate	1,179	143	36	695	181	1,320	68	120	175	120	161
NUC1600-Agg-no	1,332	524	427	1,048	541	1,626	453	505	560	505	505
NUC1600-Agg-Wind	1,753	460	354	1,077	511	1,696	388	441	495	441	449
Pumped Storage-Agg-Moderate	1,289	799	718	1,359	831	1,714	799	799	799	799	825
Simple Cycle-Agg-High	1,615	932	845	1,542	985	1,901	932	932	932	932	901

The table of expected value of differences versus best PVRR when using Low values.

Sum of L-DiffTotal	Indep Uncert										
PlanName	Cap. Costs	Decomm	DSM	EFOR	FOM	Int. Rates	NPTC	NRPTC	Nuc Fuel	OSS	VOM
Coal425W/OCCS-Agg-Moderate	577	896	1,179	433	863	-46	896	1,799	896	2,037	914
Coal425W/OCCS-Agg-no	957	1,085	1,368	653	1,078	199	1,085	1,085	1,085	1,992	1,131
Coal850W/OCCS-Agg-Moderate	474	817	1,100	346	784	-140	817	1,720	817	2,086	794
Combine Cycle-Agg-LowNoWind	718	872	1,155	445	857	-4	872	955	872	1,771	877
Combine Cycle-Agg-Moderate	518	804	1,086	340	773	-111	804	1,707	804	1,857	834
NUC1200-Agg-High	-589	349	646	-166	289	-869	389	1,895	293	2,176	325
NUC1200-Agg-LowW/Wind	257	566	897	156	596	-490	639	805	543	1,878	616
NUC1200-Agg-Moderate	-301	247	545	-214	211	-860	288	1,166	192	1,767	239
NUC1200-Agg-no	172	626	924	203	614	-426	666	640	570	1,837	643
NUC1200-Agg-Wind	-216	546	844	26	500	-633	587	1,553	491	2,174	561
NUC1600-Agg-High	-748	301	602	-205	237	-970	354	1,851	226	2,386	279
NUC1600-Agg-LowNoWind	-450	163	465	-260	140	-940	216	265	88	1,697	150
NUC1600-Agg-LowW/Wind	11	429	765	22	458	-703	517	673	388	1,926	480
NUC1600-Agg-Moderate	-709	105	404	-358	63	-1,060	155	1,024	27	1,815	89
NUC1600-Agg-no	-90	486	789	64	473	-636	540	505	412	1,870	503
NUC1600-Agg-Wind	-563	423	724	-97	373	-806	475	1,433	347	2,292	432
Pumped Storage-Agg-Moderate	506	799	1,084	333	767	-134	799	1,703	799	1,886	779
Simple Cycle-Agg-High	402	932	1,215	413	878	-58	932	2,465	932	2,221	914

The change in expected value of differences versus best PVRR from use of a High value instead of a Base value, and from use of a Low value instead of a Base value was determined from comparing entries among the tables above.

This change for the High versus Base situation is shown in the table below:

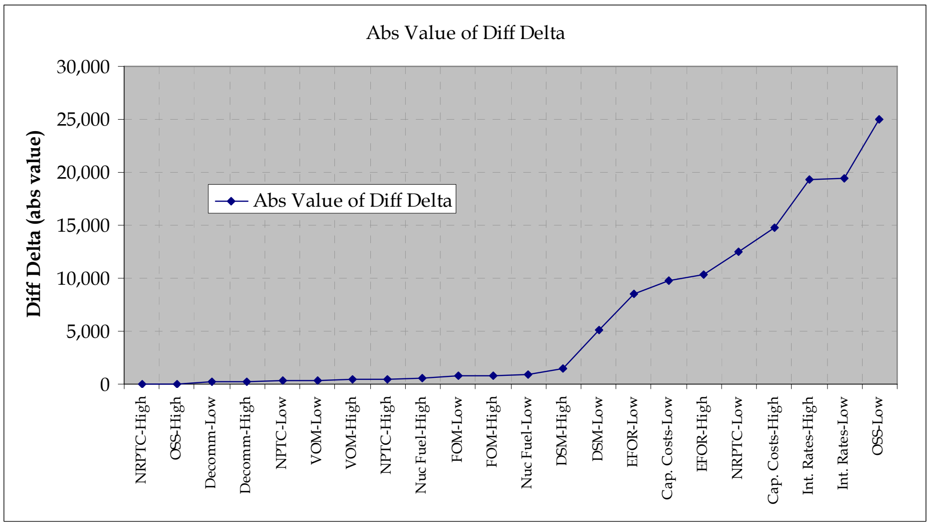
Sum of H-B Delta Diff	Indep Uncert										
PlanName	Cap. Costs	Decomm	DSM	EFOR	FOM	Int. Rates	NPTC	NRPTC	Nuc Fuel	OSS	VOM
Coal425W/OCCS-Agg-Moderate	525	0	-80	568	32	928	0	0	0	0	20
Coal425W/OCCS-Agg-no	277	0	-84	529	7	870	0	0	0	0	-15
Coal850W/OCCS-Agg-Moderate	575	0	-75	573	32	956	0	0	0	0	37
Combine Cycle-Agg-LowNoWind	315	0	-79	527	15	860	0	0	0	0	-42
Combine Cycle-Agg-Moderate	450	0	-85	564	30	903	0	0	0	0	11
NUC1200-Agg-High	1,139	14	-104	620	76	1,176	-39	0	41	0	55
NUC1200-Agg-LowW/Wind	995	14	-86	558	52	1,091	-39	0	41	0	-5
NUC1200-Agg-Moderate	894	14	-89	577	53	1,129	-39	0	41	0	30
NUC1200-Agg-no	684	14	-81	539	28	1,067	-39	0	41	0	-5
NUC1200-Agg-Wind	1,175	14	-90	636	63	1,177	-39	0	41	0	-2
NUC1600-Agg-High	1,349	19	-98	634	84	1,286	-52	0	55	0	57
NUC1600-Agg-LowNoWind	859	19	-78	543	44	1,177	-52	0	55	0	41
NUC1600-Agg-LowW/Wind	1,146	19	-86	562	60	1,219	-52	0	55	0	0
NUC1600-Agg-Moderate	1,058	19	-84	574	60	1,200	-52	0	55	0	41
NUC1600-Agg-no	827	19	-78	543	36	1,121	-52	0	55	0	0
NUC1600-Agg-Wind	1,312	19	-87	636	70	1,256	-52	0	55	0	9
Pumped Storage-Agg-Moderate	490	0	-81	560	32	915	0	0	0	0	26
Simple Cycle-Agg-High	683	0	-87	610	53	969	0	0	0	0	-31

This change for the Low versus Base situation is shown in the table below:

Sum of L-B Delta Diff	Indep Uncert										
PlanName	Cap. Costs	Decomm	DSM	EFOR	FOM	Int. Rates	NPTC	NRPTC	Nuc Fuel	OSS	VOM
Coal425W/OCCS-Agg-Moderate	-319	0	283	-463	-32	-942	0	903	0	1,141	18
Coal425W/OCCS-Agg-no	-128	0	283	-432	-7	-886	0	0	0	907	46
Coal850W/OCCS-Agg-Moderate	-342	0	283	-471	-33	-956	0	903	0	1,269	-23
Combine Cycle-Agg-LowNoWind	-154	0	283	-427	-15	-876	0	83	0	899	5
Combine Cycle-Agg-Moderate	-286	0	282	-465	-31	-915	0	903	0	1,053	30
NUC1200-Agg-High	-952	-14	283	-529	-74	-1,232	26	1,532	-70	1,813	-38
NUC1200-Agg-LowW/Wind	-356	-14	284	-457	-17	-1,103	26	192	-70	1,265	3
NUC1200-Agg-Moderate	-563	-14	283	-476	-51	-1,122	26	904	-70	1,505	-23
NUC1200-Agg-no	-469	-14	284	-438	-26	-1,066	26	0	-70	1,197	3
NUC1200-Agg-Wind	-777	-14	284	-534	-61	-1,193	26	992	-70	1,613	1
NUC1600-Agg-High	-1,067	-19	283	-524	-82	-1,289	35	1,532	-93	2,067	-41
NUC1600-Agg-LowNoWind	-632	-19	284	-441	-41	-1,121	35	83	-93	1,516	-31
NUC1600-Agg-LowW/Wind	-470	-19	284	-460	-24	-1,185	35	192	-93	1,445	-2
NUC1600-Agg-Moderate	-829	-19	283	-479	-58	-1,181	35	904	-93	1,694	-31
NUC1600-Agg-no	-595	-19	284	-441	-32	-1,141	35	0	-93	1,365	-2
NUC1600-Agg-Wind	-1,003	-19	284	-538	-68	-1,246	35	992	-93	1,852	-8
Pumped Storage-Agg-Moderate	-293	0	284	-466	-32	-933	0	904	0	1,087	-20
Simple Cycle-Agg-High	-530	0	283	-519	-54	-990	0	1,533	0	1,288	-18

To compare the impact of each of the independent uncertain factors, the sum of the absolute value of these results for each independent uncertain factor was calculated, once for the High versus Base situation, and once for the Low versus Base situation. With two situations for 11 independent uncertain factors, there are 22 results. These are shown in a table and in a chart, in ascending order of absolute value of differences, so the most impact occurs with the highest absolute value.

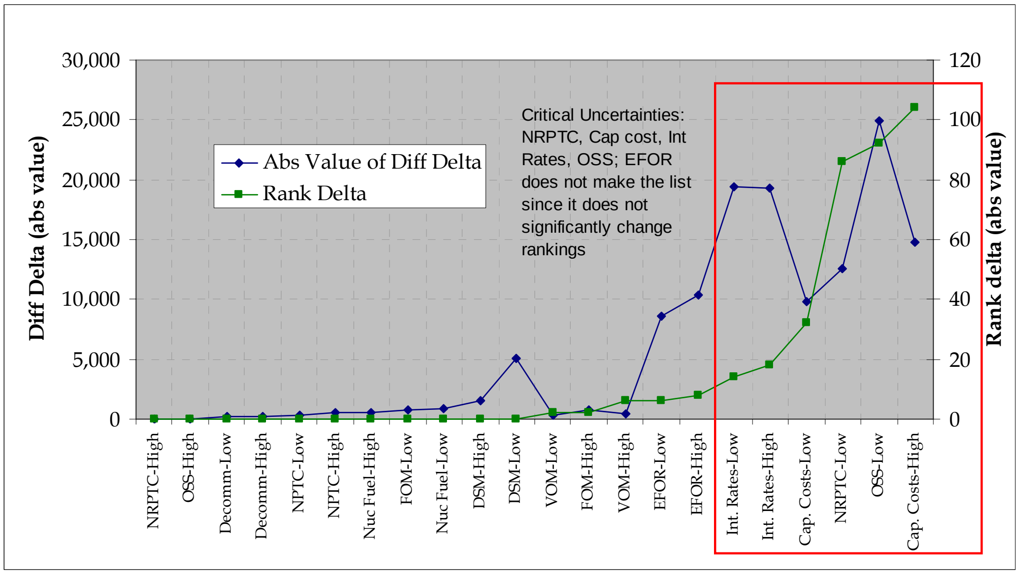
		Abs Value of Diff Delta
1	NRPTC-High	0
2	OSS-High	0
3	Decomm-Low	181
4	Decomm-High	185
5	NPTC-Low	340
6	VOM-Low	341
7	VOM-High	427
8	NPTC-High	511
9	Nuc Fuel-High	536
10	FOM-Low	740
11	FOM-High	826
12	Nuc Fuel-Low	912
13	DSM-High	1,533
14	DSM-Low	5,100
15	EFOR-Low	8,560
16	Cap. Costs-Low	9,765
17	EFOR-High	10,355
18	NRPTC-Low	12,552
19	Cap. Costs-High	14,754
20	Int. Rates-High	19,299
21	Int. Rates-Low	19,379
22	OSS-Low	24,975



Using just this one metric (change in difference versus best PVRR), there are four independent uncertain factors: OSS, Interest rate, Capital Cost and NRPTC. EFOR is the only other <u>possible</u> addition to the list, but using the second metric, rank on expected value of difference versus best PVRR, will provide further information on which of these are critical independent uncertain factors.

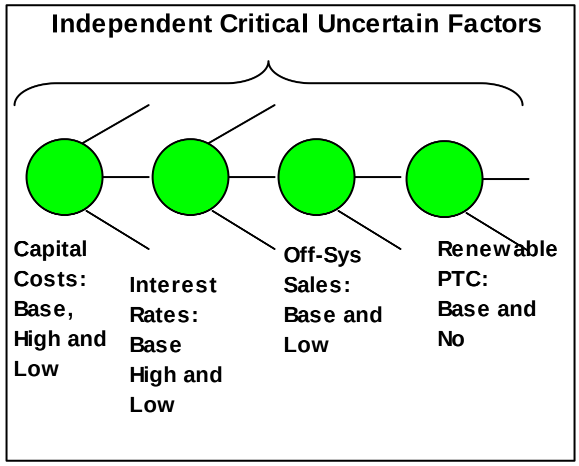
The same analysis described above for the first metric, change in difference versus best PVRR, was done with the second metric, rank on expected value of difference versus best PVRR. These results are shown together with the results of the first metric, although in ascending order of absolute value of change in rank, so this order is different than the table and chart above.

		Rank Delta	Abs Value of Diff Delta
1	NRPTC-High	0	0
2	OSS-High	0	0
3	Decomm-Low	0	181
4	Decomm-High	0	185
5	NPTC-Low	0	340
6	NPTC-High	0	511
7	Nuc Fuel-High	0	536
8	FOM-Low	0	740
9	Nuc Fuel-Low	0	912
10	DSM-High	0	1,533
11	DSM-Low	0	5,100
12	VOM-Low	2	341
13	FOM-High	2	826
14	VOM-High	6	427
15	EFOR-Low	6	8,560
16	EFOR-High	8	10,355
17	Int. Rates-Low	14	19,379
18	Int. Rates-High	18	19,299
19	Cap. Costs-Low	32	9,765
20	NRPTC-Low	86	12,552
21	OSS-Low	92	24,975
22	Cap. Costs-High	104	14,754

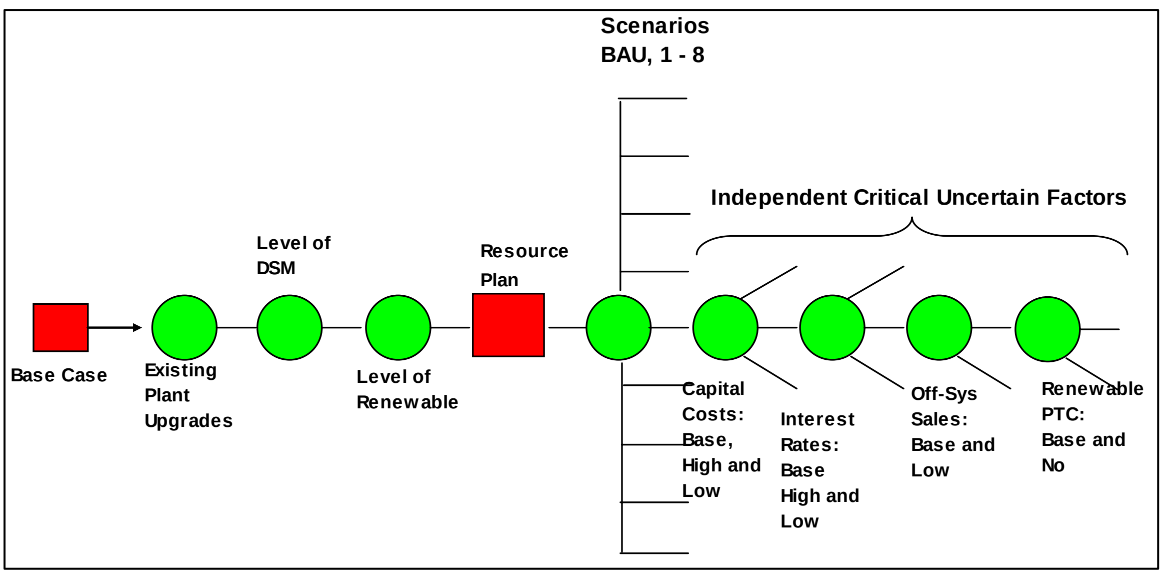


The chart highlights the 4 independent critical uncertain factors (Interest rates, Capital cost, NRPTC, OSS). It shows that EFOR is not a 5th independent critical uncertain factor. This is because while it has a relatively high impact on the first metric (change in difference versus best PVRR), it has a relatively low impact on the second metric (change in rank on that difference).

After 4 of the original 11 independent uncertain factors were determined to be critical factors, studies were then built with each of the top 18 resource plans and the 4 independent critical uncertain factors were added to the tree. An illustration of the framework for modeling each resource plan with the 4 independent critical uncertain factors is shown below:



Independent Critical Uncertain Factors created to test with top 18 resource plans.



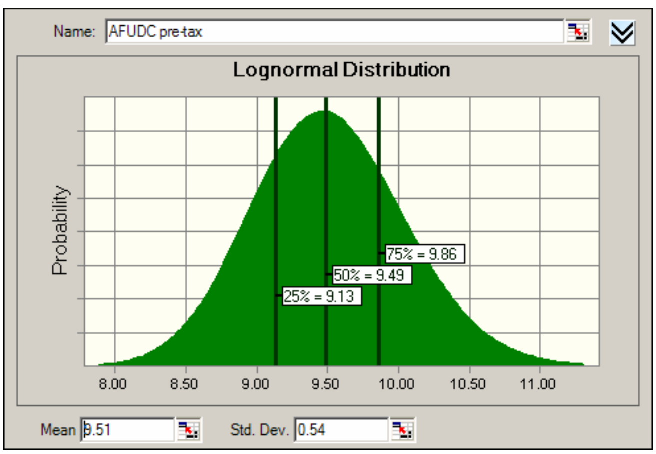
Generic Example of a study used to test the 4 Independent Critical Uncertain Factors

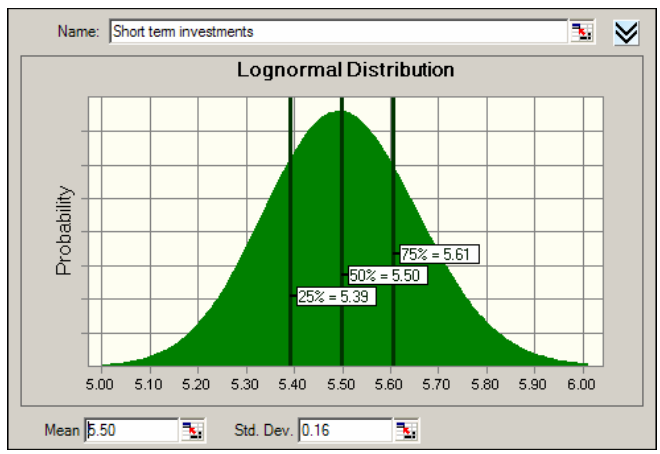
(B) Future interest rate levels and other credit market conditions that can affect the utility's cost of capital.

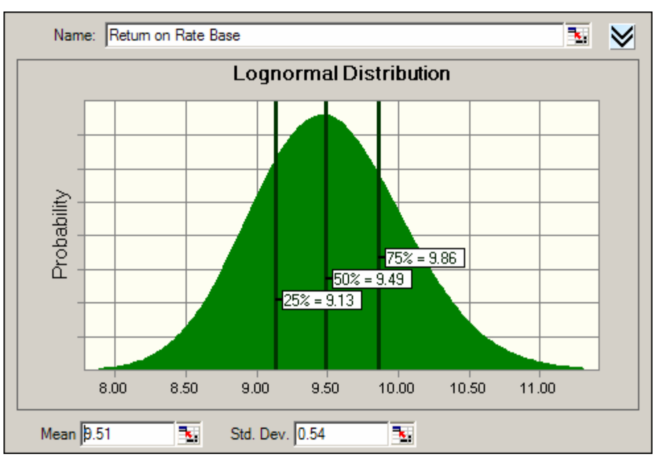
This uncertain factor was considered by a subject matter expert at AmerenUE. The following table shows the items that were considered and the range of uncertainty that was used in the MIDAS model to test the sensitivity of interest rate levels.

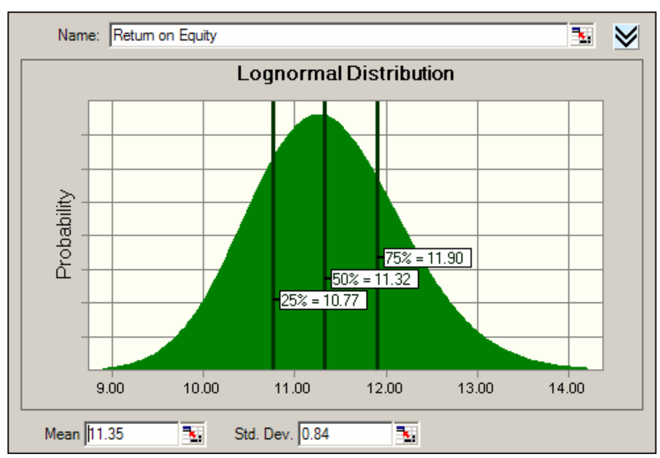
Interest (%)	Low (25%)	Base (50%)	High (25%)
AFUDC	8.76%	9.51%	10.25%
Short-term Investments	5.28%	5.50%	5.72%
Return on Rate Base	8.76%	9.51%	10.25%
Return on Equity	10.20%	11.35%	12.50%
Short-term Debt	5.28%	5.50%	5.72%
Long-term Debt	7.01%	7.25%	7.49%

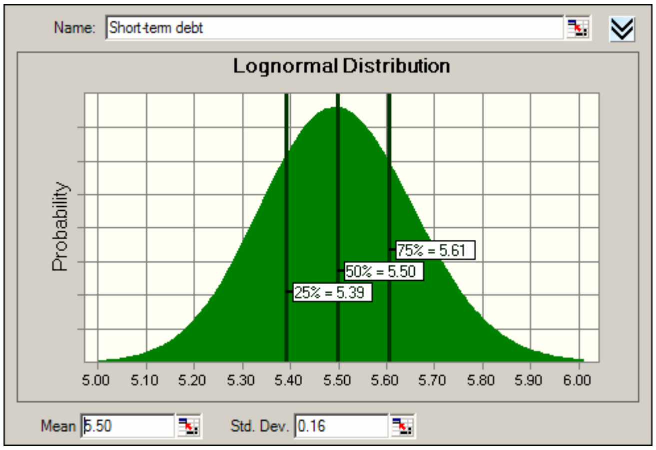
This data was converted into the implied probability distributions, a process more fully described in the immediately prior section. Values from their implied distributions at the 25th percentile were used for a Low value for each item, at the 50th percentile for the Base value, and at the 75th percentile for the High value. Their implied distributions are shown in these charts:

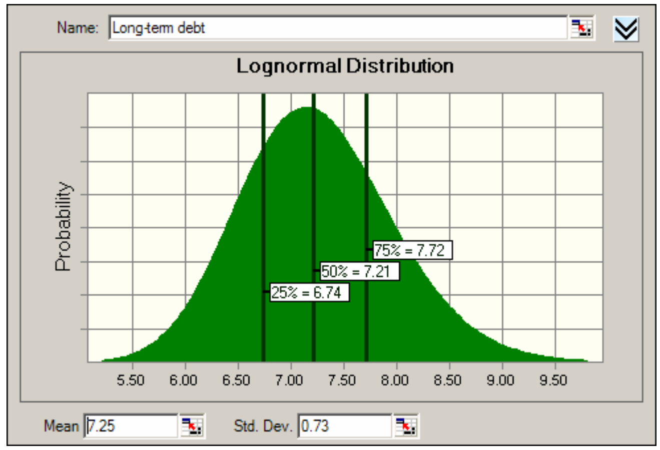












- The short-term and long-term debt rates were developed from forward projections of long and short term government securities. Union Electric bonds are sold at a premium over US securities.
- Return on Equity assumptions ranged from the allowed return on equity on the last 2007 approved rate case (10.2%) to a high estimated return of 12.5%
- The AFUDC, Return on Rate Base numbers were developed from the ranges of long-term debt and return on equity numbers above assuming the debt/equity ratio would remain at 45%/55%.
- The Return on Rate Base and AFUDC were completed on a pre-tax basis.

Based on the Independent Uncertain factor analysis interest rate levels were found to be a Critical Independent Uncertain Factor.

(D) Relative fuel prices; (Nuclear Fuel)

This independent uncertain factor was considered from the data provided by the nuclear fuel consultant as described in section 4 CSR 240-22.040 (8) (A). The impact of having a Base, High and Low nuclear fuel forecast for each of the resource plans was considered. Based on the Independent Uncertain factor analysis nuclear fuel prices were determined not to be a Critical Independent Uncertain Factor.

(E) Siting and permitting costs and schedules for new generation and generation-related transmission facilities.

This uncertain factor was considered as the data was provided by supply-side consultants, in terms of the impact of capital costs for construction for each of the resource plans considered. Based on the Independent Uncertain factor analysis capital costs were found to be a Critical Independent Uncertain Factor.

Fossil

New Generation

Siting and permitting cost were collected for each of the candidate resource options and are provided in the table below. Estimates were gathered from historical in-house Black & Veatch data based on actual siting and permitting experience. However, siting and permitting requirements are unique from project to project and change with time as environmental regulations and public opinion change. Estimates are considered representative of the technologies, but unique requirements can cause siting and permitting costs to change.

Estimates of permitting and development time along with durations from notice to proceed (NTP) to commercial operation date (COD) were collected for each of the technologies and provided in section 22.040 (1)(D). Collected information was based on current permitting and market conditions as of May 2007. Information was gathered from in-house Black & Veatch data and was based on actual Black & Veatch project experience. Estimates provided are reflective of new generation facilities.

Siting and Permitting Costs, 2007$	
	$1,000
Conventional Baseload Technologies	
BFB - 50 MW	950 – 1,800
CFB - 2x250 MW	950 – 1,800
Subcritical PC - 500 MW	950 – 1,800
Supercritical PC - 500 MW	950 – 1,800
Supercritical PC - 850 MW	950 – 1,800
Supercritical PC - 850 MW - IL No. 6	950 – 1,800
Advancing Baseload Technologies	
USCPC - 850 MW	950 – 1,800
USCPC - 850 MW - IL No. 6	950 – 1,800
Supercritical PC - 850 MW w/ CCC	950 – 1,800
IGCC - 2x1 600 MW, Shell	950 – 1,550
IGCC - 2x1 600 MW, Shell, IL No. 6	950 – 1,550
IGCC - 2x1 600 MW, Shell w/CCC	950 – 1,550
OxyComb - 850 MW	950 – 1,800
OxyComb - 850 MW w/ CCC	950 – 1,800
Supercritical CFB - 500 MW	950 – 1,800
Pressurized BFB - 250 MW	950 – 1,800
Intermediate Load Technology	
1x1 GE 7EA	650 – 1,250
1x1 GE 7FA	650 – 1,250
2x1 GE 7FA	650 – 1,250
1x1 Wartsila 12V46	650 – 1,000
2x1 Wartsila 12V46	650 – 1,000
1x1 Wartsila 18V46	650 – 1,000
Cheng Cycle - 7EA	650 – 1,000
TSB - 250 MW	650 – 1,250
Peaking Load Technology	
GE LM6000PC	650 – 1,000
GE LMS100	650 – 1,000
GE 7EA	650 – 1,000
GE 7FA	650 – 1,000
Wartsila 12V46	650 – 1,000
Wartsila 18V46	650 – 1,000

Renewables

New Generation

Siting and permitting cost were collected for each of the candidate resource options and are provided in the table below. Estimates were gathered from historical in-house Black & Veatch data based on actual siting and permitting experience. However, siting and permitting requirements are unique from project to project and change with time as environmental regulations and public opinion change. Estimates are considered representative of the technologies, but unique requirements can cause siting and permitting costs to change.

Estimates of permitting and development time along with durations from notice to proceed (NTP) to commercial operation date (COD) were collected for each of the technologies and provided in section 22.040 (1)(D). Collected information was based on current permitting and market conditions as of May 2007. Information was gathered from in-house Black & Veatch data and was based on actual Black & Veatch project experience. Estimates provided are reflective of new generation facilities.

Siting and Permitting Costs, 2007$	
	$1,000
Baseload Technologies	
Biomass Combustion – Standalone	1,000 – 1,400
Biomass Combustion – CHP	1,000 – 1,400
Biomass Combustion – Cofiring	750 – 1,200
LFG – Reciprocating Engine [1]	250 – 500
LFG – Combustion Turbine	250 – 500
Biomass IGCC	1,000 – 1,250
Waste-to-Energy – Mass Burn	1,000 – 1,400
Waste-to-Energy – RDF	1,000 – 1,400
Waste-to-Energy – Plasma Arc	1,000 – 1,400
Intermediate / Peaking Load Technologies	
Hydroelectric – Run of River [2]	750 – 1,200
Hydroelectric – Dam	2,500 – 3,000
As Available Load Technologies	
Solar Photovoltaic – Commercial	100 – 200
Parabolic Trough w/o Storage	700 – 1,000
Parabolic Trough w/ 3 hr Storage	700 – 1,000
Parabolic Dish	500 – 800
Wind Farm (Tranche 1) [3]	2,500 – 3,000
Wind Farm (Tranche 2) [3]	2,500 – 3,000
Wind Farm (Tranche 3) [3]	2,500 – 3,000
Energy Storage Technologies	
Battery Energy	NA
CAES	NA

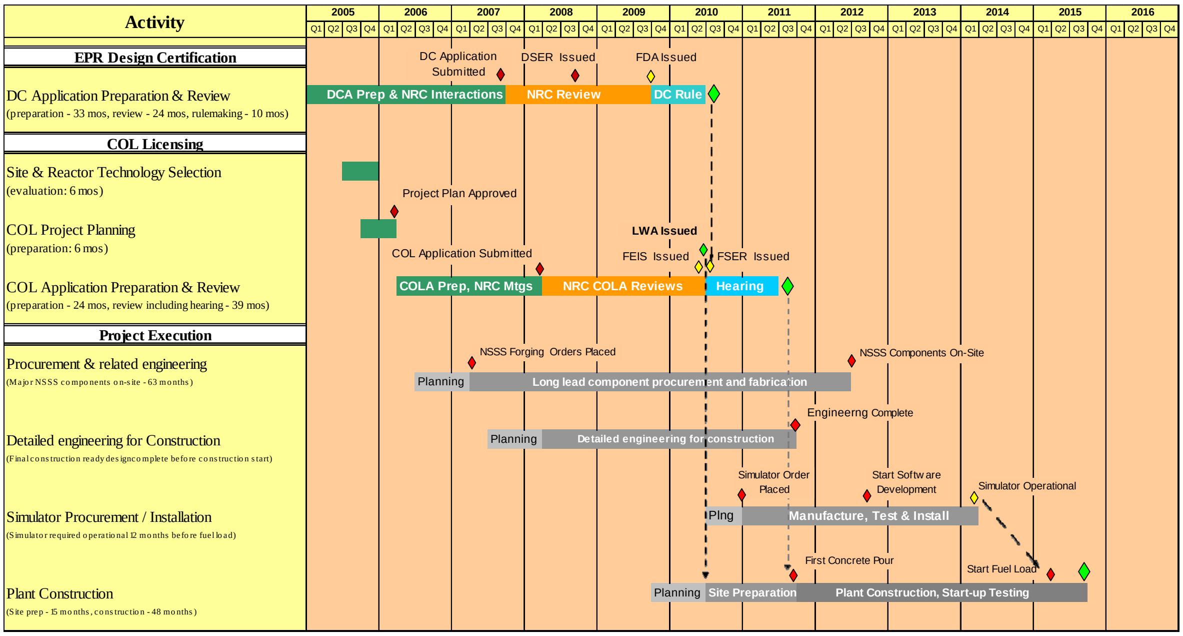
Notes:
[1] LFG siting and permitting costs include resource study (e.g., an SCS study), LFG rights negotiation and land lease negotiations.
[2] Hydroelectric – Run of River siting and permitting costs assume that you are selecting a final site from a discrete list of candidate sites.
[3] Wind Tranche 1, 2, and 3 siting and permitting costs include land acquisition and project conceptual design (layout, ect.)

Nuclear

Siting costs are minimized through the use of the existing Callaway Site. Siting and permitting costs are included in the allowance for owner's costs. A 25 percent allowance for owner's cost is included in the base capital cost forecast. Owner's cost can vary from less that 20 percent to over 35 percent. Siting and permitting costs are a relatively small portion of the owner's costs. The siting and permitting costs included in the owner's costs are $70,000,000 for the COLA and $5,000,000 for state and local permitting. These costs can vary significantly up or down, but should be within the range of the overall variance of the owner's costs.

The US-EPR reference schedule is presented below.

US-EPR Reference Schedule



The reference schedule with the COLA submitted at the beginning of the second quarter 2008 and provisional turnover at the beginning of the fourth quarter 2015, offers ample time for AmerenUE to construct an US-EPR for commercial operation for the first quarter of 2018.

The table below presents the estimated ranges and probabilities related to the construction schedule.

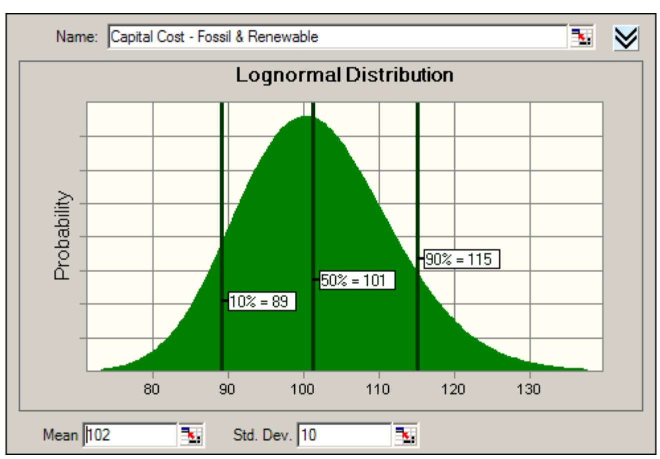
Estimated Ranges and Probabilities US-EPR Construction Schedule		
Deviation from Base	Construction Schedule (months)	Probability
-6%	45	10%
Base	48	40%
6%	51	20%
19%	57	15%
31%	63	10%
50%	72	5%

Generation-related transmission facilities associated with the addition of the US-EPR are limited to a new plant substation connected to the transmission system by very short transmission lines. This very small amount of generation-related transmission facilities can easily be constructed within the time frame of the construction of the unit.

(F) Construction costs and schedules for new generation and transmission facilities.

This uncertain factor was considered as the data was provided by supply-side consultants, in terms of the impact of capital costs for construction for each of the resource plans considered.

In this case, as mentioned in the earlier more complete description of how the raw data for independent uncertain factors was used, the Low case was analyzed using the value at the 10th percentile of the probability distribution implied by the raw data, and the High



case was analyzed using the value at the 90th percentile of the probability distribution implied by the raw data.

Based on the Independent Uncertain factor analysis capital costs were found to a Critical Independent Uncertain Factor. Reference 4 CSR 240-22.040 (8) (B) for ranges and subjective probabilities.

Fossil

New Generation

Generic screening-level overnight capital costs were collected for each of the technologies and provided in Section 22.040 (1)(E). The cost estimates were based on current market conditions as of May 2007. Capital cost estimates were gathered from in house Black & Veatch data and were factored to be reflective of a generic Midwest US installation. The capital cost estimates were based on previous Black & Veatch estimates.

Estimates of permitting and development time along with durations from notice to proceed (NTP) to commercial operation date (COD) were collected for each of the technologies and provided in section 22.040 (1)(D). Collected information was based on current permitting and market conditions as of May 2007. Information was gathered from in-house Black & Veatch data and was based on actual Black & Veatch project experience. Estimates provided are reflective of new generation facilities.

Renewables

New Generation

Generic screening-level overnight capital costs were collected for each of the technologies and provided in Section 22.040 (1)(E). The cost estimates were based on current market conditions as of May 2007. Capital cost estimates were gathered from published literature and in-house Black & Veatch data, and actual Black & Veatch project experience. Cost estimates were factored to be reflective of a generic Midwest US installation.

Estimates of permitting and development time along with durations from notice to proceed (NTP) to commercial operation date (COD) were collected for each of the technologies and provided in section 22.040 (1)(D). Collected information was based on current permitting and market conditions as of May 2007. Information was gathered from published literature and in-house Black & Veatch data and based on actual Black & Veatch project experience. Estimates provided are reflective of new generation facilities.

Nuclear

The evolutionary approach adopted for the US-EPR allows its construction schedule to benefit from extensive construction experience of Framatome ANP. Provisions have been made in the design, construction, erection and commissioning methods to shorten the EPR construction schedule as much as possible.

Design Features -- The general layout of the main safety systems in four trains housed in four separate buildings simplifies, facilitates and shortens performance of the erection tasks for all work disciplines. Location of electromechanical equipment at low levels means that it can be erected very early on in the program, thus shortening the critical path of the construction schedule.

Construction and Erection Methods -- Three main principles are applied to the EPR construction and erection: minimization of the interfaces between civil works and erection of mechanical components, modularization and piping prefabrication.

- *Minimization of the interfaces between civil works and erection.* Implementation of a construction methodology "per level" or "grouped levels" enables equipment and system erection work at level "N", finishing construction works at level "N+1" and main construction work at levels "N + 2" and "N + 3" to be carried out simultaneously; this methodology is used for all the different buildings except for the reactor building, where it cannot apply.

- *Use of modularization for overall schedule optimization.* Modularization techniques are systematically considered, but retained only in cases where they offer a real benefit to the optimization of the overall construction schedule without inducing a technical and financial burden due to advanced detailed design, procurement or prefabrication. This approach enables the site preparation schedule to be optimized, delays investment costs with regard to start of operation, and so offers financial savings.

- *Maximization of piping and support prefabrication.* Piping and support prefabrication is maximized in order to minimize erection man-hours and especially welding and controls at erection places; this measure also results in an even better quality of the piping spools with lower cost.

Commissioning Tests -- As with the interfaces between civil and erection works, the interfaces between erection and tests have been reviewed and optimized. Instrumentation & Control factory acceptance tests are carried out on a single test platform with all cabinets interconnected, will ensure a shorter on-site test period together with improved overall quality.

The benefits drawn from the Framatome ANP's past experience and current EPR projects provide confidence that the EPR schedule is achievable.

(G) Purchased power availability, terms and costs.

Uncertainty around off system sales

To model the uncertainty around off system sales AmerenUE used the modeling assumptions for the AmerenUE RTO cost benefit study filed with the Missouri PSC on November 1, 2007. The relevant Seams Charge section from that study is included below.

Seams Charges

Seams charges are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, seams charges are applied to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Seams charges are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch.

Both commitment and dispatch seams charges were applied in this study. For RTOs with day-ahead markets, the unit commitment seams charge was set at zero within the RTO and at $10/MWh between the RTO and adjoining control areas. The commitment seams charge was set at $10/MWh between all other control areas. Dispatch hurdles were set at applicable non-firm off-peak wheeling rates1 plus a dispatch friction rate. For RTOs with active managed markets, the frictional rate was set at zero for flows within the RTO, and at 3 $/MWh for flows out of the RTO. For flows from all other control areas, the frictional rate was set at 5 $/MWh.

The MISO/PJM seams management is assumed to yield a 1 $/MWh reduction in the dispatch seams charge between these two RTOs. Prior to 2011, SPP is modeled with the standard $10/MWh commitment seams charges between SPP control areas to model that the SPP commitment is not RTO-wide. Intra-RTO SPP dispatch seams charges are reduced to $1/MWh to take into account the balancing market that is in operation in SPP. Beginning in 2011, the intra-SPP commitment and dispatch seams charges are set to zero as in the Midwest ISO.

The table below gives an overview of the wheeling rates between SPP, MISO, AmerenUE and other neighboring control areas for all scenarios.

[1] Based on the current tariff, the AmerenUE out and through rate in the ICT case was set at $1 per MWh. GE MAPS requires wheeling rates to be rounded to an integer. The current AmerenUE rate is $1.04 per MWH. Based on current tariffs, the non-firm out and through rate for the Midwest ISO was set at $3 per MWh and for the SPP RTO at $2 per MWh. No wheeling rates were applied for flows within the SPP RTO or within the Midwest ISO. Given current policies, no wheeling rates were applied between PJM and the Midwest ISO.

Seams Charges for SPP, Midwest ISO and AmerenUE by Scenario

From	To	Commitment Seams Charge	Dispatch Seams Charge Wheeling Off-peak	Friction*	Total
MISO	SPP	10	3	3	6
MISO	PJM	10	0	2	2
MISO	AmUE ICT	10	3	3	6
MISO	All Other	10	3	3	6
PJM	MISO	10	0	2	2
PJM	Other	10	2	3	5
SPP 09	MISO	10	2	5	7
SPP 09	AmUE ICT	10	2	5	7
SPP 09	All Other	10	2	5	7
SPP 09	SPP 09	10	0	1	1
SPP 11	SPP 11	0	0	0	0
SPP 11	MISO	10	2	3	5
SPP 11	AmUE ICT	10	2	3	5
SPP 11	All Other	10	2	3	5
AmUE ICT	All	10	1	5	6
LG&E	All	10	1	5	6
Entergy	All	10	2	5	7
AECI	All	10	2	5	7
TVA	All	10	2	5	7
MEC	All	10	3	5	8
All Other	All Other	10	2	5	7

Dispatch
* $3 dispatch friction hurdle for flows out of active managed markets
* Non market areas not expected to be as efficient hence higher dispatch friction hurdle of $5
* Non-firm off peak hourly rate used in addition to friction
* SPP 09 intra-pool dispatch friction set at $1 given balancing market
* PJM to/from MISO friction set at $2 given extensive seams management process

As is described in the section above, in case AmerenUE is not part of an RTO it will have to overcome a seams charge for making off system sales. There are two types of seams charges used in the GE MAPS model used in the cost benefit study – a Commitment Seams Charge and a Dispatch Seams Charge. The Midas model used in the Integrated Resource Planning analysis has the ability to only input one charge. If AmerenUE is not part of an Regional Transmission Operator it will commit units in advance to meet expected next day load and sales opportunities. Therefore the commitment hurdle is more appropriate to use in the Midas model than the dispatch hurdle. Hence the low off system sales scenario is modeled using $10/MWh as the hurdle rate required to be overcome in Midas for making opportunistic off system sales.

This uncertain factor was considered by modeling the Off-System Sales in the MIDAS model. This independent uncertain factor was tested using two different methods. The original intent was to test off-system sales using just a $10/MWh hurdle rate as described in the section above. However, the first method tested included not only the $10/MWh hurdle rate but also a physical transmission constraint. The addition of a physical transmission constraint serves to further limit off-system sales in each of the top 18 resource plans tested. The analysis of off-system sales, when using the first method tested, when compared to the other 11 independent uncertain factors shows off-system sales to be one of the top four critical independent uncertain factors.

The second method tested (and our intended method) used only $10/MWh as a hurdle rate required to be overcome in the Midas model for making opportunistic off-system sales (OSS). The results from the second method, using just a single constraint (the $10/MWh hurdle rate), were directionally the same as those produced by the first method which had two constraints (the $10/MWh hurdle rate plus a physical transmission constraint).

This conclusion is based on using the same two metrics used in all of the analyses regarding independent uncertain factors, with these two metrics described in more detail earlier in this section. The values for these two metrics from the first analysis (which has the unintended and more constraining first method for OSS) are shown in the nearby table, which was shown earlier in this section.

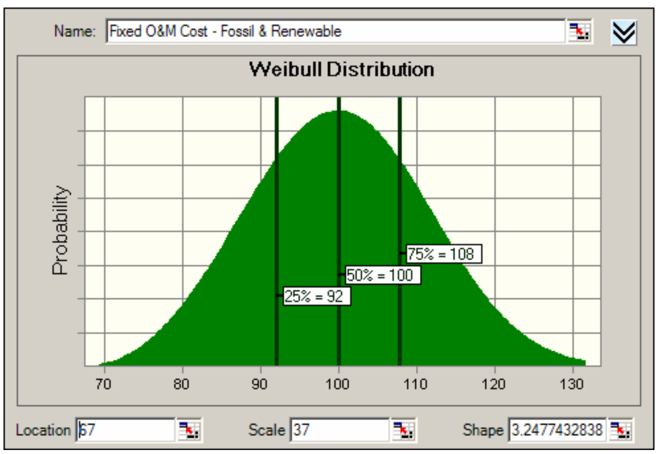
In this copy of that same earlier table, the "Low OSS" results for the two metrics from the first analysis are highlighted in yellow. Substituting the "OSS-Low" results from the second (intended) method means that the existing entry for "OSS-Low" of 92 in the first column of numbers would become 62, and the 24975 in the second column of numbers would become 19965.

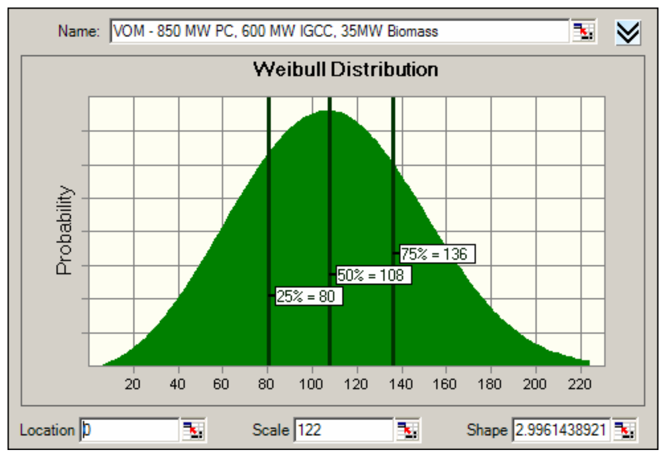
		Abs Valu Rank Delta	Abs Valu Diff Delta
1	NRPTC-High	0	0
2	OSS-High	0	0
3	Decomm-Low	0	181
4	Decomm-High	0	185
5	NPTC-Low	0	340
6	VOM-Low	2	341
7	VOM-High	6	427
8	NPTC-High	0	511
9	Nuc Fuel-High	0	536
10	FOM-Low	0	740
11	FOM-High	2	826
12	Nuc Fuel-Low	0	912
13	DSM-High	0	1,533
14	DSM-Low	0	5,100
15	EFOR-Low	6	8,560
16	Cap. Costs-Low	32	9,765
17	EFOR-High	8	10,355
18	NRPTC-Low	86	12,552
19	Cap. Costs-High	104	14,754
20	Int. Rates-High	18	19,299
21	Int. Rates-Low	14	19,379
22	OSS-Low	92	24,975

Both of these new values would clearly rank at the top end of the range of values in their respective columns. A value of 62 in the first column of numbers would be the 3rd highest number in that column, while a value of 19965 in the second column of numbers would be the highest number in that column, meaning OSS is significant. It is the relative values on these two metrics among these independent uncertain factors that are decisive, not the individual values themselves. This means the same conclusion would hold: OSS, regardless of which of the two methods used, is one of four Critical Independent Uncertain Factors.

(I) Fixed operation and maintenance costs for existing generation facilities.

This uncertain factor was considered for new supply-side resources as the data was provided by supply-side consultants. In addition to the Fixed operation and maintenance the data supplied for the variable operation and maintenance data was tested as a sensitivity. Both items, via the analysis, were determined not to be a Critical Independent Uncertain Factor.





Examples of some of the probability distributions for FOM and VOM are in the two charts above.

Existing resources were considered but determined most likely not to have a substantial impact on the outcome of the various supply-side resource plans since all of the existing resources are common across all resource plans. Reference 4 CSR 240-22.040 (8) (C) for ranges and subjective probabilities.

<u>Fossil</u>

Generic screening-level fixed operations and maintenance (O&M) costs were collected for each of the technologies and provided in Section 22.040(1)(F). The fixed O&M cost estimates were gathered from in-house Black & Veatch data and were factored to be reflective of a generic Midwest US installation. The fixed O&M cost estimates were based on previous Black & Veatch estimates.

<u>Renewables</u>

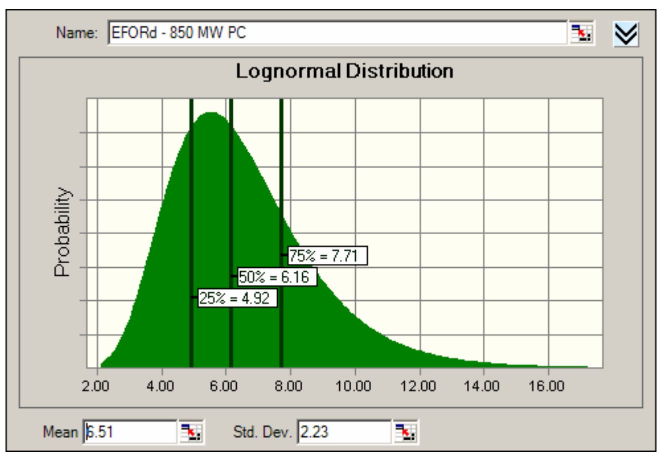
Generic screening-level fixed operations and maintenance (O&M) costs were collected for each of the technologies and provided in Section 22.040(1)(F). The fixed O&M cost estimates were gathered from in-house Black & Veatch data and were factored to be reflective of a generic Midwest US installation. The fixed O&M cost estimates were based on previous Black & Veatch estimates.

<u>Nuclear</u>

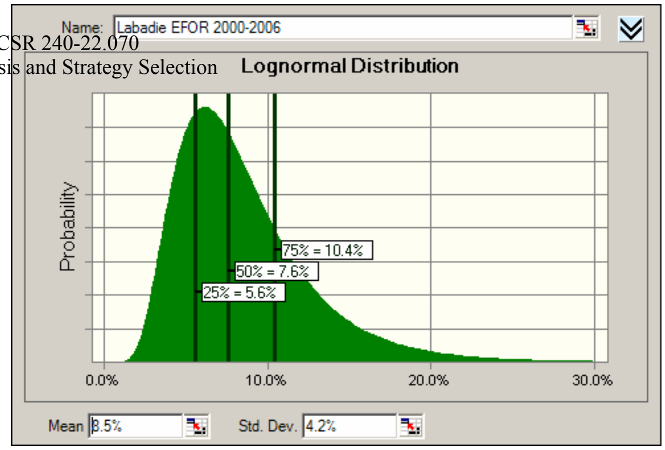
Only new nuclear generation technologies were evaluated.

(J) Equivalent or full- and partial-forced-outage rates for new and existing generation facilities.

This uncertain factor was analyzed based on data provided by supply-side consultants for the various new supply-side resources. An example of the EFORs coming from use of that raw outside data for new supply-side resources is the implied probability distribution for EFOR for an 850 MW PC plant.



For AmerenUE's existing fleet internal data was collected and used in this analysis. An example of an existing plant's EFOR can be seen in the implied probability distribution for the Labadie plant's EFOR shown in the nearby chart.



EFOR, via the analysis, was determined not to be a Critical Independent Uncertain Factor.

The analysis was conducted using a "derate" approach to modeling EFOR as opposed to another possible approach. That other approach consists of a unit being in one of two conditions, either in (1) a randomly-occurring random-duration full outage condition or (2) running at its full capacity.

The derate approach means that the value of EFOR was used as a "derate" or reduction in capacity for the entire time period. In this approach, a unit's capacity for the analysis is the reduced amount for the entire period. For example, with a 3% EFOR for a 500 MW unit, the derate approach would use 485 MWs as the unit's capacity for all hours, derived by taking (100% - 3%) times 500 MWs.

An alternative approach, using randomly-occurring random-duration full outages, was used in another analysis discussed in 4 CSR 240-22.070(7). In that alternative approach, a unit experiences random occurrences of outages according to probability distributions of outage frequency and outage duration.

<u>Fossil candidate resource options EFOR</u>

Forced outage rate data were obtained from the NERC GADS database, which tracks reliability data for plants throughout the United States. NERC GADS does not report the forced outage rate (FOR). Instead, it reports equivalent forced outage rate (EFOR). For baseloaded units, this is a reasonable measure of forced outage. However, the data become somewhat skewed when examining peaking units. In this instance, EFORd (EFOR demand) becomes a more representative value because it takes into account when forced outages occur within the context of periods of demand. A narrative comparison of EFOR to EFORd is provided in

4 CSR 240-22.040 Appendix K.

Probability distributions for EFORd for the candidate resources options, as taken from NERC GADS, are shown in table below.

EFORd Uncertainty Distribution.			
850 MW Supercritical PC			
EFOR Deviation	4	8	12
EFORd Deviation	4	8	12
Probability	-25	50	+25
600 MW IGCC			
EFOR Deviation	10	13	16
EFORd Deviation	10	13	16
Probability	-25	50	+25
LMS 100			
EFOR Deviation	2	14	26
EFORd Deviation	2	5	9
Probability	-25	50	+25
7FA			
EFOR Deviation	4	17	30
EFORd Deviation	1	5	9
Probability	-25	50	+25
2x1 7FB			
EFOR Deviation	1	4	6
EFORd Deviation	1	3	5
Probability	-25	50	+25

Renewable candidate resource options EFOR

Forced outage rate data were obtained from the NERC GADS database, which tracks reliability data for plants throughout the United States, published literature, and internal Black & Veatch resources. Where data were not available, they were estimated using data gathered from comparable technologies. The data are generic but representative for screening-level supply-side resource analyses. NERC GADS does not report the forced outage rate (FOR). Instead, it reports equivalent forced outage rate (EFOR) and equivalent forced outage rate demand (EFORd). For baseloaded units, this is a reasonable measure of forced outage. However, the data can become somewhat skewed when investigating units with lower annual demand, such as peaking units. In this instance, EFORd becomes a more representative value because it takes into account when forced outages occur within the context of periods of demand. Although none of the screened technologies are peaking units, EFORd is still provided. A narrative comparison of EFOR to EFORd is provided in Appendix K.

Probability distributions for EFOR and EFORd for the candidate resources options are shown below..

EFOR and EFORd Uncertainty Distribution.			
Biomass Combustion - Standalone			
EFOR Deviation	7	10	13
EFORd Deviation	7	10	12
Probability	-25	50	+25
Biomass Combustion - Cofiring			
Deviation	4	8	12
EFORd Deviation	4	8	12
Probability	-25	50	+25
LFG – Reciprocating Engine			
Deviation	3	8	12
EFORd Deviation	3	7	11
Probability	-25	50	+25
LFG – Combustion Turbine			
Deviation	2	7	12
EFORd Deviation	2	6	11
Probability	-25	50	+25
Hydroelectric – Run of River			
Deviation	1	3	8
EFORd Deviation	1	3	7
Probability	-25	50	+25
Wind			

Deviation	3	5	7
EFORd Deviation	NA	NA	NA
Probability	-25	50	+25

Nuclear

NERC GADS defined the *Forced Outage Factor* as the number of forced outage hours (FOH) divided by the number of hours in the period (PH) under consideration, or [FOH/PH] x 100 (%). For purposes of the data provided to AmerenUE, the forced outage factor was considered indicative of the forced outage rate. NERC GADS statistics were queried for US nuclear units for the years 1996 through 2005. From this data, the 10-year average forced outage factor was calculated to be approximately 5.6 percent, with a range between 1.9 percent (in 2005) and 11.2 percent (in 1996). The trend in forced outage factors indicated that throughout the 1996 – 2005 period, forced outage factors for the US nuclear generating fleet have been decreasing, and forced outage factors have been less than or equal to 4 percent for 2001 through 2005.

Based on the NERC GADS data described above and industry estimates of forced outage rates for new nuclear generating technologies (including the US-EPR), the expected forced outage rate was estimated to be 2.0 percent, and sensitivities were developed for forced outage rates of 3.0 percent and 4.0 percent. A 70 percent probability was assigned to the expected 2.0 percent forced outage rate based on the industry projections as well as current trends, and 20 percent probability and 10 percent probability were assigned to the 3.0 percent and 4.0 percent forced outage rate sensitivities, respectively, in order to reflect current trends while still capturing potential increases in forced outage for new nuclear generation. Below are these projections.

Forced Outage Rate Projections			
Forced Outage Rate	Expected	Sensitivity	Sensitivity
Value	2.0%	3.0%	4.0%
Likelihood (3 values sum to 100%)	70%	20%	10%

NERC GADS data for US nuclear units for the years 1996 through 2005 was used to develop projections of unit forced outage frequency and associated likelihood. NERC GADS reports the fleet wide average number of occurrences of forced outages each year. Over the 10 year period considered, the average number of annual occurrences ranged from less than 2 forced outages per year to more than 15 forced outages per year. Within this range, there were 3 years where the number of forced outages was less than 2 per year, 4 years where the number of forced outages was between 2 and 6 per year, and 3 years where the number of forced outages was greater than 6 per year. Based on this information, projections of frequency of outages and likelihood were developed.

Frequency of Forced Outage Rate Projections			
Forced Outage Rate	Low	Base	High
Frequency (times per year)	2	4	10
Likelihood (3 values sum to 100%)	30%	40%	30%

(K) Future load impacts of demand-side programs.

The sensitivity analysis to identify the uncertainty factors of demand-side programs are detailed in 4 CSR 240-22.040 Appendix B, Section A.7, pages 143 to149. Uncertainty factors around the load impacts can be found in Section 7.3.3, pages 145 to 147, of the document titled 4 CSR 240-22.040 Appendix B.

This uncertain factor was considered as the data was provided by the demand-side management consultant, ICF. Only the Aggressive portfolio was used in the Independent Uncertainty analysis as all top 18 plans had that level of DSM. DSM, via the analysis, was determined not to be a Critical Independent Uncertain Factor.

(L) Utility marketing and delivery costs for demand-side programs.

The sensitivity analysis to identify the uncertainty factors of demand-side programs are detailed in 4 CSR 240-22.040 Appendix B, Section A.7, pages 143 to149. Uncertainty factors around the utility costs can be found in Section 7.3.4, pages 147 to 149, of the document titled 4 CSR 240-22.040 Appendix B.

This uncertain factor was considered as the data was provided by the demand-side management consultant, ICF. Only the Aggressive portfolio was used in the Independent Uncertainty analysis as all top 18 plans had that level of DSM. DSM, via the analysis, was determined not to be a Critical Independent Uncertain Factor.

(Other) Future impact of renewable production tax credits.

This uncertain factor was considered as a case when there could be a time in the future when there would be "no" renewable production tax credits available. Based on that uncertainty it would therefore be beneficial to test this uncertain factor on the top 18 resource plans. No renewable tax credits, via the analysis, were determined to be a Critical Independent Uncertain Factor.

(Other) Future impact of nuclear production tax credits.

This uncertain factor was considered as a case when there could be a time in the future when there could be either a higher or lower amount of nuclear production tax credits available. Based on that uncertainty it would therefore be beneficial to test this uncertain factor on the top 18 resource plans. The data for the Base, High and Low cases was provided by an outside consultant. Nuclear production tax credits (Base, High and Low), via the analysis, were determined not to be a Critical Independent Uncertain Factor.

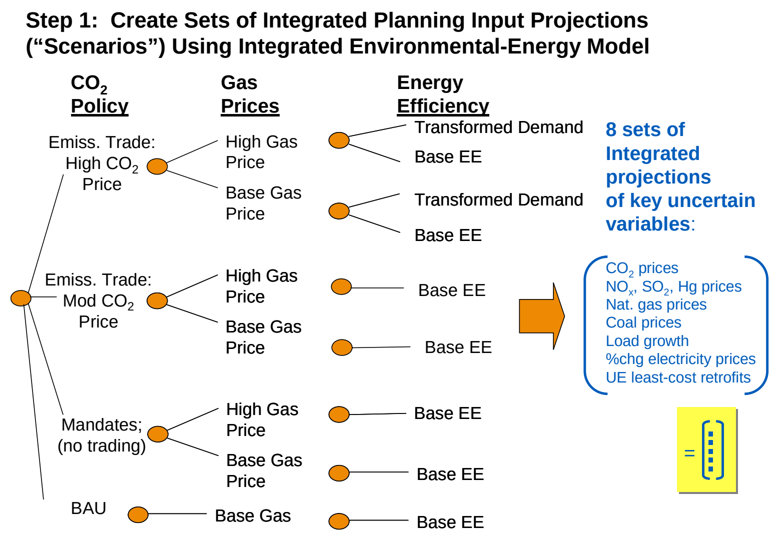
(Other) Future impact of decommissioning costs.

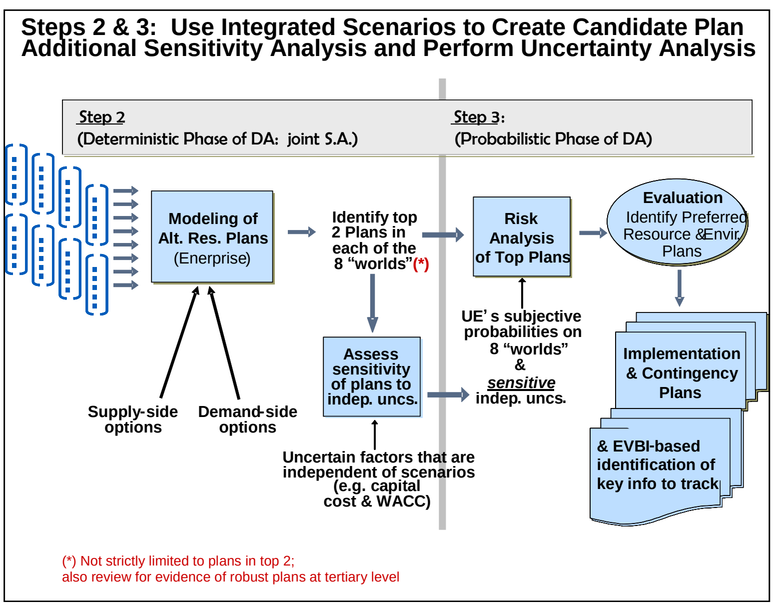
This uncertain factor was considered as a case when there could be a time in the future when there could be either a higher or lower amount of nuclear decommissioning costs required. Based on that uncertainty it would therefore be beneficial to test this uncertain factor on the top 18 resource plans. The data for the Base, High and Low cases was provided internally by an AmerenUE subject matter expert. Nuclear decommissioning costs, via the analysis, were determined not to be a Critical Independent Uncertain Factor.

4 CSR 240-22.070 (3)

AmerenUE will construct a probability-tree diagram that appropriately represents the interdependent critical uncertain factors that affect the performance of the resource plans.

See the responses to section 4 CSR 240-22.030 (7), 4 CSR 240-22.040 (2) (B) 1- 3, and 4 CSR 240-22.040 (8) (A) for an exposition of how the load growth, CO_2 policy, and natural gas price branches of the probability tree were developed, and how AmerenUE assigned subjective probabilities to each of these scenarios. The figure below presents the final structure of the probability tree.





Scenario-Based Process for Handling Environmental and Other Risks in IRP.

4 CSR 240-22.070 (4)

(4) The decision-tree diagram for all alternative resource plans shall include at least two (2) chance nodes for load growth uncertainty over consecutive subintervals of the planning horizon. The first of these subintervals shall be not more than ten (10) years long..

AmerenUE requested and received a complete waiver from the requirement of section 4 CSR 240-22.070 (4).

4 CSR 240-22.070 (5)

The utility shall use the probability-tree formulation to compute the cumulative probability distribution of the values of each performance measure specified pursuant to 4 CSR 240-22.060(2), contingent upon the identified uncertain factors and associated subjective probabilities assigned by utility decision-makers pursuant to section (1) of this rule. Both the expected performance and the risks of each alternative resource plan shall be quantified.

(A) The expected performance of each resource plan shall be measured by the statistical expectation of the value of each performance measure.

Before launching the probabilistic analysis, AmerenUE first identified a subset of resource plans from the breadth of generating technology, demand-side management (DSM), and renewable portfolio options analyzed in the deterministic phase. The 18 alternative resource plans that AmerenUE eventually selected were judged to most likely produce the preferred plan under uncertainty. This uncertainty is characterized both by the CO_2 policy, natural gas price, and load growth nodes in the scenario tree, and also by the independent uncertain factors[1] deemed critical to resource plan performance. Figure 1 below presents the final probability tree that formed the backbone of the probabilistic analysis. As noted, AmerenUE tested the robustness of each top plan against the various settings of the critical factors that form the tree's branches, resulting in 324 endpoints. For the purposes of ranking preferred plans in this probabilistic context, AmerenUE used the probability-weighted average PVRR.

[1] The critical independent uncertain factors included in the probabilistic analysis were capital costs, interest rates, off-system sales, and the existence of a renewable production tax credit.

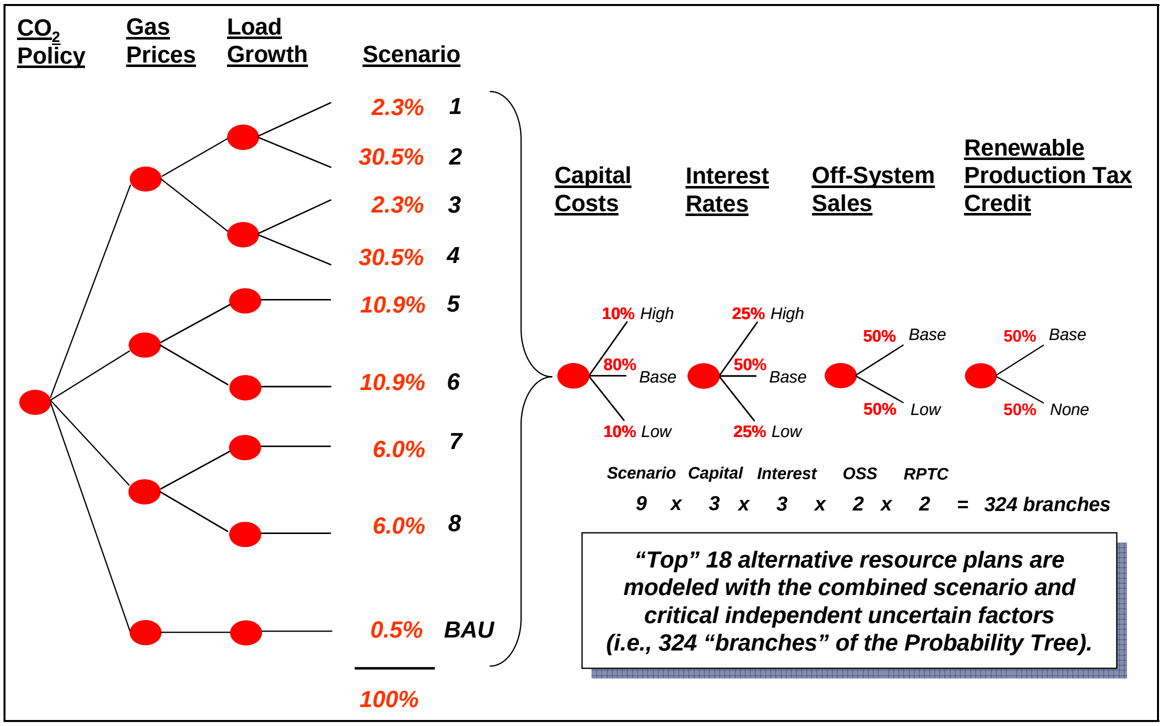


Figure 1: Final Probability Tree with Independent Critical Uncertain Factors.

The expected performance of each of the top 18 alternative resource plans was then computed by deriving the expected PVRR across the 324 different states, where each state represents a unique combination of the three scenario and four critical independent uncertain factors. The probability of each state is simply the joint probability of assuming a particular parameter of each of these seven uncertainties. Consider, for example, that one is in the following state: the BAU scenario, high capital costs, high interest rates, base off-system sales, and base renewable production tax credit. Then, the joint probability assigned to the PVRR outcome in this state would be the product of 0.5%, 10%, 25%, 50%, and 50%, or 0.003125%.[2] By weighting each of the 324 PVRR outcomes by the so-determined joint probabilities, AmerenUE arrived at an expected PVRR, in millions of dollars, for each resource plan. Table 1 demonstrates that the preferred alternative resource plan as measured by the expected PVRR performance measure is NUC1600-Agg-LowNoWind, with the next five top-performing plans also including nuclear capacity.

[2] Note that this calculation assumes that the uncertainties are probabilistically independent of one another.

Table 1: Probability-Weighted PVRR for Top 18 Alternative Resource Plans.

Resource Plan	Expected PVRR ($ millions)
NUC1600-Agg-LowNoWind	39,221
NUC1600-Agg-Moderate	39,404
NUC1600-Agg-no	39,414
NUC1200-Agg-Moderate	39,457
NUC1200-Agg-no	39,468
NUC1600-Agg-LowW/Wind	39,582
Combine Cycle-Agg-LowNoWind	39,584
NUC1200-Agg-LowW/Wind	39,611
Combine Cycle-Agg-Moderate	39,753
Coal425W/OCCS-Agg-no	39,758
Pumped Storage-Agg-Moderate	39,767
Coal850W/OCCS-Agg-Moderate	39,882
Coal425W/OCCS-Agg-Moderate	39,892
NUC1200-Agg-High	39,945
NUC1600-Agg-Wind	40,020
NUC1200-Agg-Wind	40,026
NUC1600-Agg-High	40,049
Simple Cycle-Agg-High	40,256

(B) The risk associated with each resource plan shall be characterized by some measure of the dispersion of the probability distribution for each performance measure, such as the standard deviation or the values associated with specified percentiles of the distribution.

When formulating cumulative probability distributions and associated percentiles, calculating the difference of each resource plan from the "best" plan in the 324 states is particularly insightful. In the context of the PVRR performance criterion, it allows AmerenUE decision makers to quantify the "regret"[3] attached to sub-optimal resource plans over the probability distribution generated by the scenario and critical independent uncertainties. To clarify, if *i = {Resource Plan 1, Resource Plan 2, …, Resource Plan 18}* represents the top 18 alternative resource plans given in Table 1 and *j = {State 1, State 2, …, State 324}* represents the

[3] Regret would result if you happened to find yourself in a state where your preferred plan is not the lowest cost plan in that state. The regret can be quantified as the difference in PVRR in that state between the chosen plan and the lowest cost plan in that state.

324 distinct states resulting from the various combinations of scenario and critical independent uncertainties, then the difference from "best" plan *i** in a given state *j* is as follows:

$$PVRR\ Diff_{i,j} = PVRR_{i^*,j} - PVRR_{i,j}$$

A simple corollary of the above formulation is that, for the best plan in a particular end state, the PVRR difference is zero; that is, there is no regret when choosing the best plan. More generally, the smaller the sum of the PVRR differences across all 324 states, the more preferred the plan should be. Table 2 presents the expected value of the PVRR differences for each of the top 18 resource plans in ascending order, where the joint (scenario and critical independent) probabilities of each state are used as weights. Alongside this expected value computation is the probability that each resource plan is the best. This second measure starts to hint at the risk embodied in the PVRR probability distribution of each resource plan. As an illustrative example, consider the NUC1600-Agg-LowNoWind plan. Of the 324 endpoints of the probability tree in Figure 1, NUC1600-Agg-LowNoWind is superior (by the PVRR difference performance measure) on branches that constitute 54.6% of the overall likelihood. In other words, AmerenUE will have zero regret in choosing this plan 54.6% of the time, given the probability distribution generated by the scenario and critical independent uncertainties. On the other hand, the NUC1200-Agg-Moderate resource plan, despite being ranked fourth by the expected value criterion, has no chance of having zero regret.

Table 2: Expected Value of the PVRR Differences from the "Best" Plan (in Ascending Order), alongside the Probability of Being the Best Plan.

		Expected Value of Difference from Best Plan (PVRR - $ millions)	Probability of Being the Best Plan
1	NUC1600-Agg-LowNoWind	214	54.6%
2	NUC1600-Agg-Moderate	396	14.2%
3	NUC1600-Agg-no	407	0.2%
4	NUC1200-Agg-Moderate	450	0.0%
5	NUC1200-Agg-no	460	0.6%
6	NUC1600-Agg-LowW/Wind	575	0.0%
7	Combine Cycle-Agg-LowNoWind	576	11.5%
8	NUC1200-Agg-LowW/Wind	603	0.0%
9	Combine Cycle-Agg-Moderate	745	2.7%
10	Coal425W/OCCS-Agg-no	751	7.5%
11	Pumped Storage-Agg-Moderate	759	2.3%
12	Coal850W/OCCS-Agg-Moderate	874	0.0%
13	Coal425W/OCCS-Agg-Moderate	885	0.0%
14	NUC1200-Agg-High	937	1.1%
15	NUC1600-Agg-Wind	1,013	0.0%
16	NUC1200-Agg-Wind	1,019	0.0%
17	NUC1600-Agg-High	1,041	1.6%
18	Simple Cycle-Agg-High	1,249	3.7%

To assess the risk of greater levels of regret across the full range of probability, constructing a cdf of the PVRR differences is informative. Figure 2 depicts the cdf of each resource plan's level of regret.[4] In general, curves with the following properties are advantageous: (1) being concentrated to the left, such that lower levels of regret have comparably higher probabilities, and (2) approaching the 100% boundary more rapidly, such that higher regret values have comparably small probabilities. In a sense, these two properties weigh using (1) lower expected values against (2) lower spreads or standard deviations as relevant

[4] The cdf curves were colored according to the generation technology of the alternative resource plan. The green line signifies the resource plan that is optimal in terms of both its expected value and the probability of being best (*i.e.*, NUC1600-Agg-LowNoWind). The other NUC1600 plans are given in blue, whereas the NUC1200 plans are in purple and pink, the combined cycle plans are in orange, the coal plans are in black and gray, the pumped storage plan is in brown, and the simple cycle plan is in dotted gold. The order of the resource plans in the legend is determined by the expected value of the PVRR difference from the best plan.

performance criteria.[5] This second property is an important measure of the risk of a resource plan, in that AmerenUE wishes to minimize the chance of absorbing an inordinate level of regret.

A stochastically dominant resource plan would have a cumulative probability function that lies to the left of every other curve across the domain of PVRR differences. Figure 2 demonstrates that no such resource plan exists. However, consistent with Table 2, it is noteworthy that the green line representing the NUC1600-Agg-LowNoWind alternative resource plan rests on the vertical axis for 54.6% of its probability. This has the powerful implication that the median difference from the best plan, in terms of PVRR millions of dollars, is zero. However, the dark purple curve representing the NUC1200-Agg-Moderate plan surpasses, in terms of being the leftmost line, the green curve at around the 88% probability mark. To fully understand what this means, a closer interpretation of these curves is merited. Looking at the vertical line extending from the $500 million marker on the horizontal axis, the green curve intercepts this threshold at around 82%, whereas the dark purple curve intersects this vertical line at around 62%. This implies that the NUC1600-Agg-LowNoWind resource plan has a roughly 20% higher likelihood than the NUC1200-Agg-Moderate plan of suffering a regret level less than $500 million. Examining these curves' intersection of the $1,000 million vertical line, though, confirms that the NUC1200-Agg-Moderate plan has roughly a 5% greater probability than the NUC1600-Agg-LowNoWind of having a regret level less than $1 billion. Finally, at regret levels greater than around $1.5 billion, these two curves converge close to the 100% barrier. At such substantial levels of regret, these two resource plans become nearly indistinguishable in a probabilistic sense. It should nevertheless be underscored again that the NUC1600-Agg-LowNoWind plan is preferred to all other resource plans for 88% of the overall likelihood. Appendix E discusses the levels of risk aversion at which AmerenUE might prefer (over NUC-1600-Agg-LowNoWind) other plans that have lower probabilities of higher regret and, as such, are less exposed to exorbitant losses.

[5] If one envisions the probability distribution function of each alternative resource plan's PVRR differences, the first property would prescribe that the best plan have a mean PVRR difference closest to zero, while the second property would prescribe that the right tail of the distribution be the thinnest.

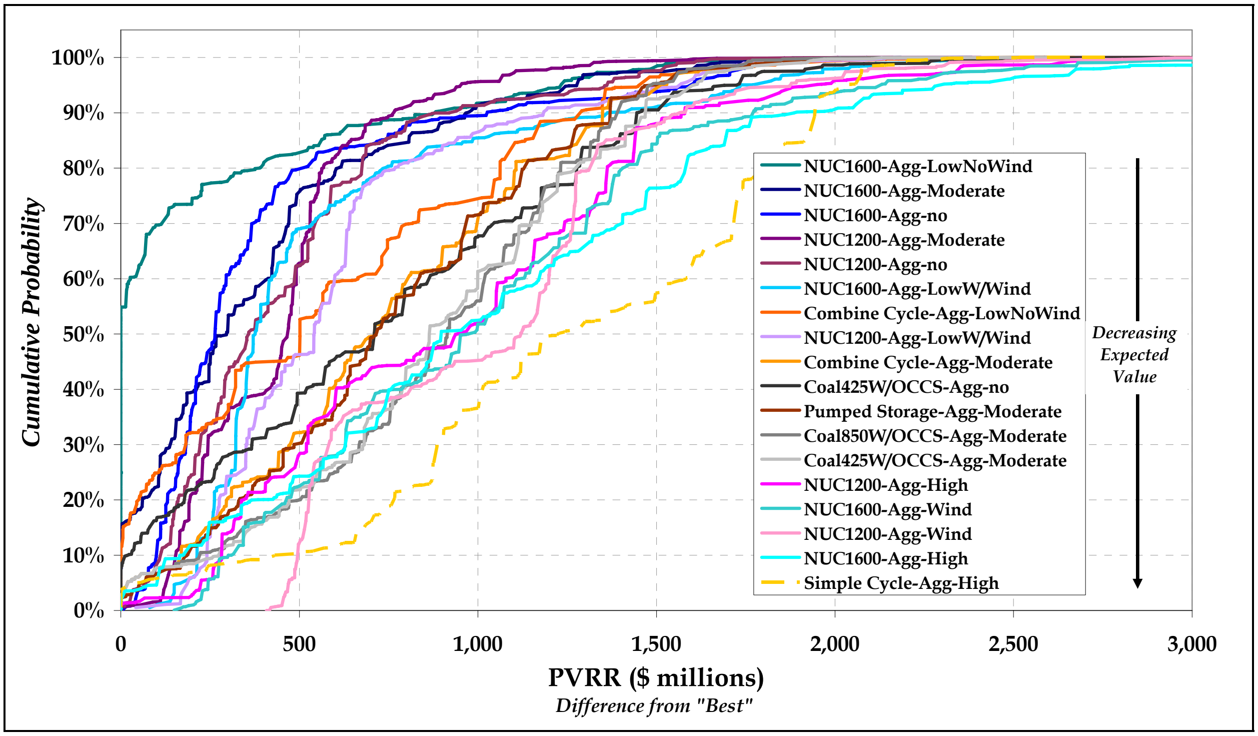


Figure 2: Cumulative Probability Distributions of the PVRR Difference from the "Best" Plan ($ Millions).

Figure 3 exemplifies the same trends as in Figure 2, but in terms of deciles of cumulative probability. The alternative resource plans are labeled in accordance with the enumeration in Table 2, sorted from lowest to highest by the expected PVRR difference. Where Figure 3 is particularly incisive is in its clear juxtaposition of the 80%, 90%, and 100% percentiles for each resource plan. In Figure 2, groups of build plans cluster close to one another at levels of cumulative probability higher than 80%, and it is at this end of the probability distribution where AmerenUE potentially faces very high levels of regret. In addition to minimizing the expected value of regret, another objective governing the selection of the preferred resource plan involves minimizing the risk of these extremely undesirable outcomes. Figure 3 corroborates that the NUC1600-Agg-LowNoWind resource plan is exceedingly robust in terms of risk. The 0% to 80% percentiles are lower than the counterparts of every other resource plan. Moreover, the 100% percentile, representing the maximum regret outcome, is lower than every other plan except for NUC1200-Agg-no, where the difference is negligible. The red and green circles surrounding the 90% and 100% deciles of resource plan 1 and 4 revisit the comparison of the NUC1600-Agg-LowNoWind and the NUC1200-Agg-Moderate plans. Of note is how resource plan 1 (NUC1600-Agg-LowNoWind) has a lower 100% percentile despite having a higher 90% percentile. This indicates that the NUC1200-Agg-Moderate plan is not superior to the NUC1600-Agg-LowNoWind for all regret values greater than the point of intersection exhibited in Figure 2. Especially when observing the large jump in expected value between resource plans 1 and 2 (the difference between the dark red circles equal to $182 million), the NUC1600-Agg-LowNoWind plan proves to be the preferred course of action by this performance measure.

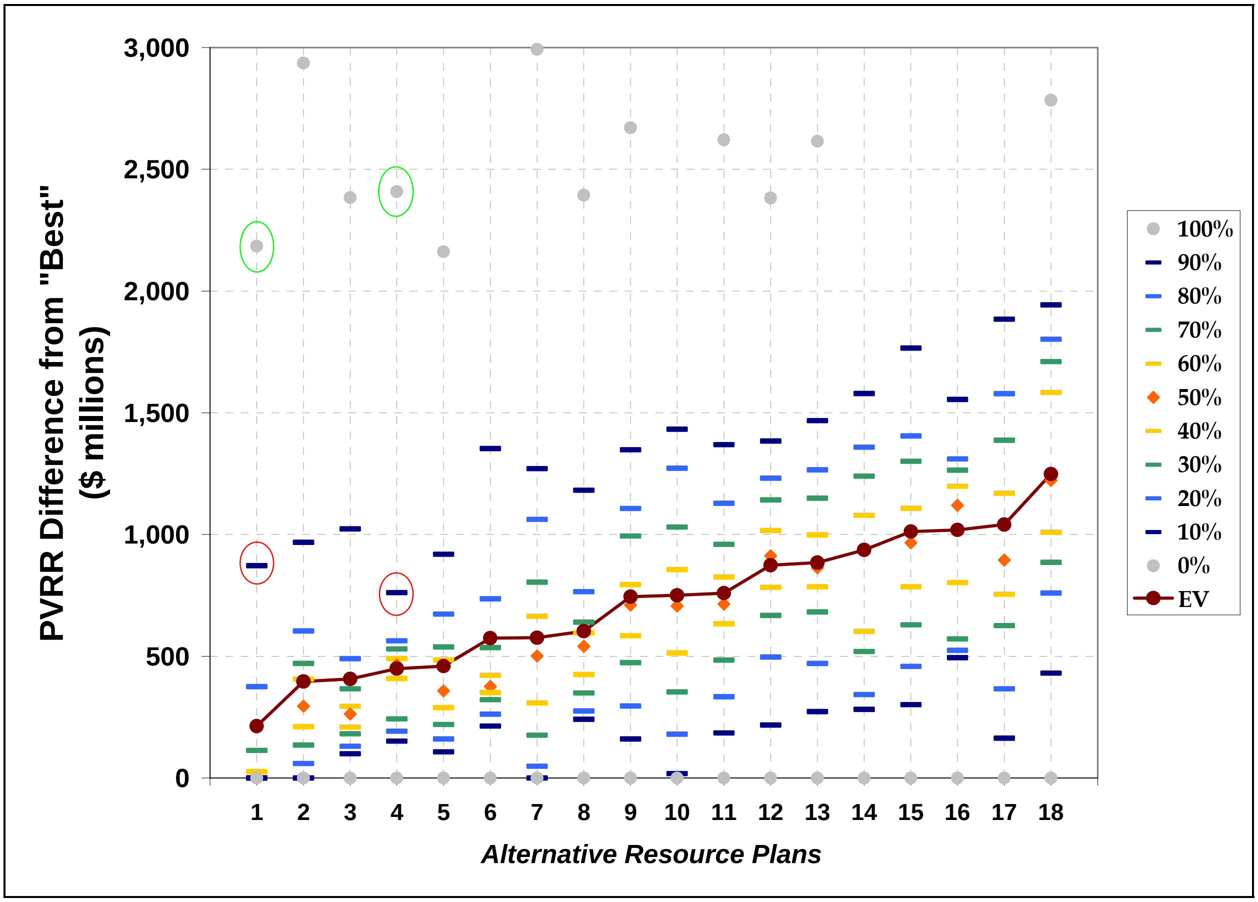


Figure 3: Percentiles of Cumulative Probability of the PVRR Difference from "Best" Plan for the Top 18 Alternative Resource Plans.

Figure 4 again presents the cdf for the top 18 alternative resource plans, but instead in terms of absolute PVRR values (rather than PVRR differences). Because smaller PVRR values are preferred to larger values, desirable cumulative distribution functions exhibit the same properties as previously delineated for PVRR differences. That is, preferred curves should (1) concentrate to the left, such that greater cumulative probability is attributable to smaller PVRR outcomes, and (2) approach the 100% horizontal as quickly as possible, such that the resource plan avoids the adverse, extremely high PVRR outcomes. Again, a stochastically dominant resource plan would be given by a cdf that appears to the left of every other curve across the entire range of PVRR values.

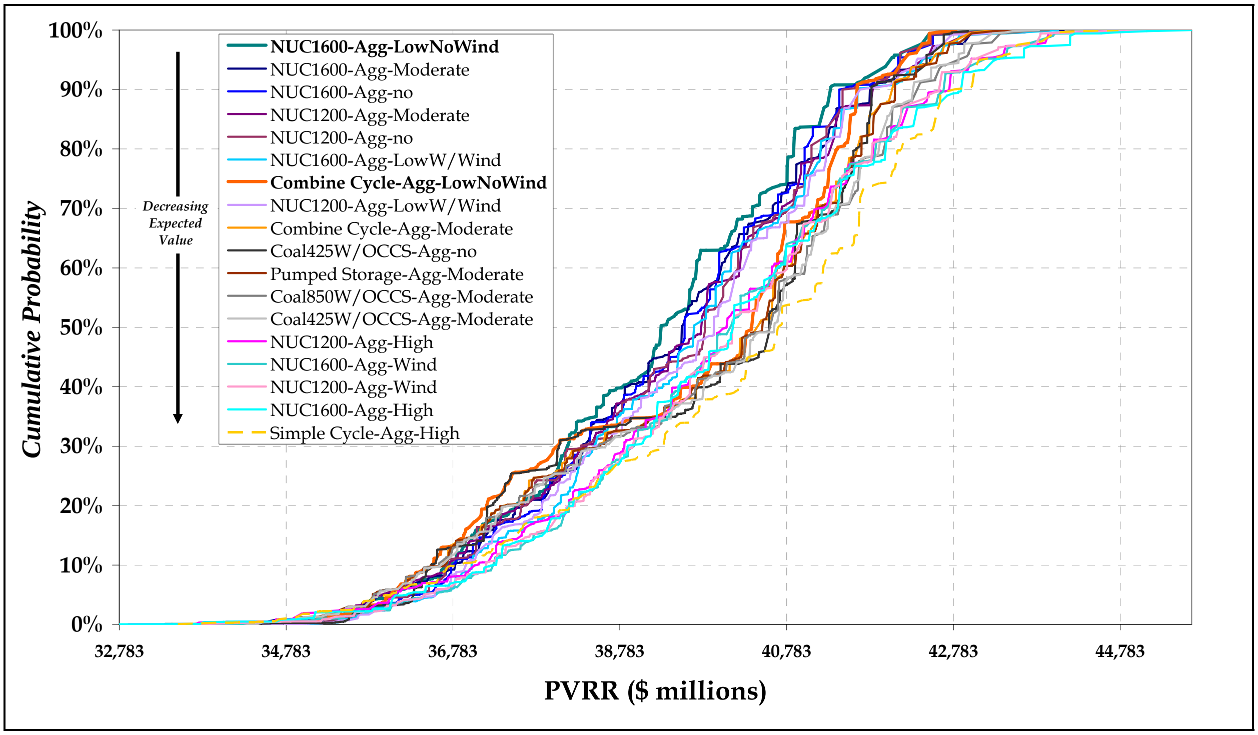


Figure 4: Cumulative Probability Distributions of PVRR ($ Millions).

Figure 4 reestablishes that no such resource plan exists. In fact, the emboldened orange line representing the Combine Cycle-Agg-LowNoWind resource plan seems to dominate the NUC1600-Agg-LowNoWind over some ranges of the cumulative probability. Figure 5 presents only the curves for these two resource plans, and confirms that the Combine Cycle-Agg-LowNoWind has a higher probability of lower PVRR values for the range of probability from roughly 5% to 30%, and also at the peak of the curve slightly below 100%. Note, however, that the “advantage” in these ranges that the Combine Cycle-Agg-LowNoWind plan enjoys over the NUC1600-Agg-LowNoWind plan is not that significant. Looking at the vertical extending from the $37,382 PVRR value, the orange line representing the Combine Cycle-Agg-LowNoWind plan has around a 23% probability of having a PVRR less than $37,382 million, whereas the NUC1600-Agg-LowNoWind plan has around an 18% probability of having a PVRR less than that value. This gap pales in comparison to the greater margins achieved by the NUC1600-Agg-

LowNoWind plan in the 40% to 90% cumulative probability range. Moreover, as the diamond markers denote, the NUC1600-Agg-LowNoWind plan has a lower expected PVRR value by around $363 million.

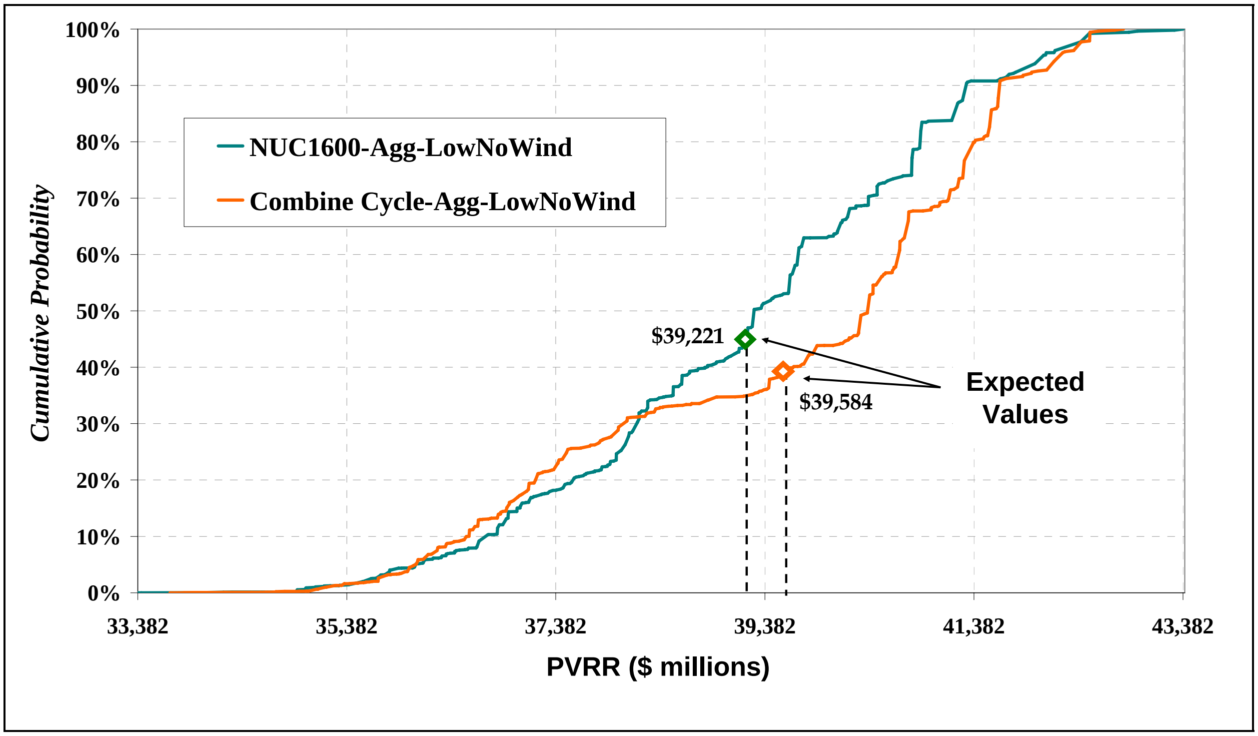


Figure 5: Cumulative Probability Distribution Functions of PVRR for the NUC1600-Agg-LowNoWind and Combine Cycle-Agg-LowNoWind Alternative Resource Plans.

Figure 6 charts the deciles of cumulative probability in terms of absolute PVRR values (similar to Figure 3 for PVRR differences), and encircles in red the percentiles for which the Combine-Cycle-Agg-LowNoWind resource plan has a lower PVRR than the preferred NUC1600-Agg-LowNoWind plan.[6] Figure 6 reaffirms the preferred plan's (*i.e.*, NUC1600-Agg-LowNoWind) dominance over the majority of the probability engendered by the scenario and critical independent uncertainties.

[6] The alternative resource plans in Figure 6 are presented in the same order (by expected value ascending) as in Figure 3.

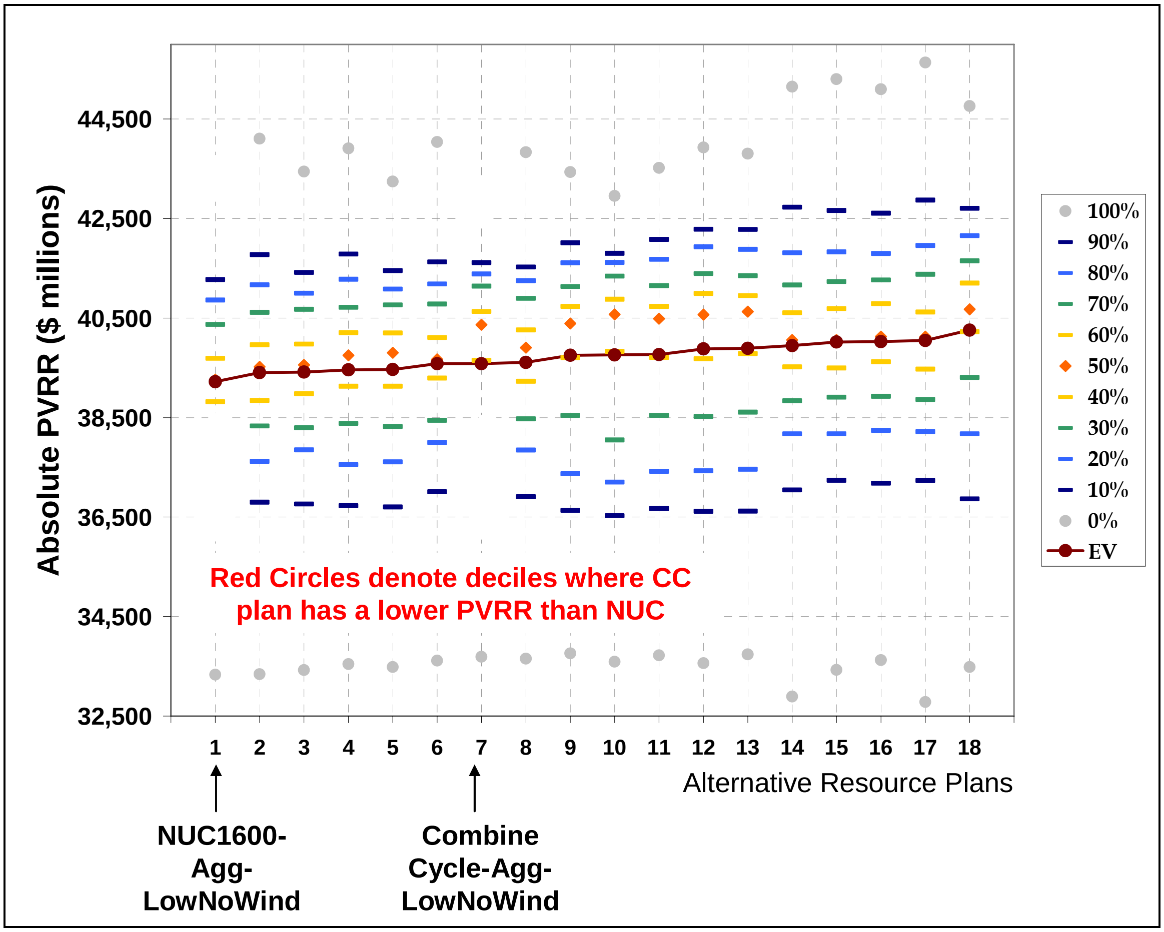


Figure 6: Percentiles of Cumulative Probability of PVRR for the Top 18 Alternative Resource Plans.

The fact that the Combine-Cycle-Agg-LowNoWind plan is "better" in four out of ten deciles indicates that additional investigation is necessary. Through this point in the analysis, risk neutrality[7] was implicitly assumed. This entails that there is a linear relationship between AmerenUE's utility[8] and the PVRR of an alternative resource plan across the entire domain of PVRR values. Equivalently, $1 million PVRR increases from, say, $35,382 million to $36,382 million or from $41,382 million to $42,382 million result in exactly the same decrease in

[7] Risk neutrality implies that a decision-maker faced with a proposition with uncertain outcomes is indifferent between that uncertain proposition and the expected value of the outcomes. Mathematically, if the utility function for a variable *x* is given by u(*x*), then risk neutrality over some range of *x* implies u(*x*) is linear over that range of *x*.
[8] The utility, or utility function, is a function that assigns each outcome in an uncertain proposition a corresponding number, or utility level. This utility level denotes the level of satisfaction gleaned from an outcome; in the context of the IRP, the utility function would assign a utility level to each resource plan's PVRR outcome.

AmerenUE's utility. However, if AmerenUE is risk averse[9] to extremely bad outcomes, its utility might drop more from a PVRR increase from $41,382 million to $42,382 million than from a PVRR increase from $35,382 million to $36,382 million. Because the Combine Cycle-Agg-LowNoWind plan has a lower maximum PVRR value, as reflected in a lower 100% percentile, there might be a level of risk aversion (where high PVRR outcomes are weighted more negatively) at which the Combine Cycle-Agg-LowNoWind resource plan would be preferred to the NUC1600-Agg-LowNoWind resource plan. Appendix E presents this risk aversion analysis, and ultimately concludes that the risk aversion necessary to vault the Combine Cycle-Agg-LowNoWind resource plan past the NUC1600-Agg-LowNoWind plan is well beyond expected levels of risk aversion. Thus, comprehensive probabilistic analyses, in terms of both absolute PVRR values and PVRR differences from the "best" plan in each end state, establish that the NUC1600-Agg-LowNoWind alternative resource plan is the preferred option under risk neutrality and under reasonable levels of risk aversion.

[9] Risk aversion implies that a decision-maker faced with a proposition with uncertain outcomes would prefer the expected value of the outcomes to the uncertain proposition. Mathematically, if the utility function for a variable x is given by $u(x)$, then risk aversion over some range of x implies $u(x)$ is concave downward over that range of x. Intuitively, risk aversion simulates the desire to avoid the possibility of large losses. In turn, in the context of the IRP, a risk averse decision-maker would assign greater and greater "disutility" to high PVRR outcomes.

4 CSR 240-22.070 (6)

The utility shall select a preferred resource plan from among the alternative plans that have been analyzed pursuant to the requirements of 4 CSR 240-22.060 and sections (1)–(5) of this rule.

AmerenUE's Preferred Plan:

Energy Efficiency - Our goal for reducing demand on our system through implementation of energy efficiency programs is 540 megawatts by 2025. We also believe that our strong support for energy efficiency initiatives will not only benefit the environment but provide an economic boost through the creation of jobs in "green" energy industries, like the development and growth of businesses focused on selling energy efficient appliances, providing highly efficient industrial processing equipment or weatherizing homes and commercial operations. However, while we are committed to advancing our operation's and customers' efficiency efforts, we need time to realize the benefits of these programs, monitoring their effectiveness and gathering data to determine their actual impact.

Expansion of Existing Renewable Generation - In addition, our target is to serve an additional 3 percent of retail electric sales through new renewable resources by 2020. Our plan calls for expanding the role of renewable energy sources in our overall power generation mix, which means not only the development of renewable energy sources, but also increased hydroelectric generation capacity through upgrades at our Osage and Keokuk plants. We are exploring the viability of other renewable energy sources, including solar power, biomass, landfill gas and wind power. Going forward, we plan to even more fully analyze the technical and economic potential for development of renewable resources in our region.

Continue To Increase Unit Efficiency - The plan also factors in a continued commitment to increased generating unit efficiency. Over the years, while we have focused heavily on making all operations more efficient, continued improvements at our existing plants are expected to yield us in the range of 90 to 200 megawatts of additional capacity. That would bring total AmerenUE capacity, which stands now at 9,957 megawatts, above 10,000 megawatts.

Unit Retirement Expected - In 2009, the company will complete an analysis that will indicate which generating units in AmerenUE must be retired. The IRP indicates which units are likely candidates for retirement, specifically units at Meramec Plant, and states that, even with effective implementation of

Exploring Technologies To Reduce Carbon - Our analysis clearly shows that developing reliable electricity supplies for Missouri customers will eventually require development of baseload power plants – the estimated time frame for that is 2018 to 2020. For that reason, we are preserving the option for additional nuclear generation, while researching clean coal and carbon sequestration technologies. In addition, we will continue to explore and test innovative new technologies for reducing emissions, particularly CO2.

Commitment to Environmental Stewardship - Based on the subjective probability results shown in the response to 4 CSR 240-22.040 (8) (D), and the retrofit installations included in Appendix G for the 9 scenarios, AmerenUE's preferred retrofit installation plan is as follows:

Wet FGD – Sioux 1 & 2 in 2010

Halogenated Activated Carbon Injection System – Meramec 3 & 4 in 2015

Halogenated Activated Carbon Injection System – Rush Island 1 & 2 in 2015

Halogenated Activated Carbon Injection System – Labadie 1 – 4 in 2015

The preferred resource plan shall satisfy at least the following conditions:

(A) In the judgment of utility decision-makers, the preferred plan shall strike an appropriate balance between the various planning objectives specified in 4 CSR 240-22.010(2); and

4 CSR 240-22.010 (2) (A)

Consider and analyze demand-side efficiency and energy management measures on an equivalent basis with supply-side alternatives in the resource planning process.

Each of the alternative resource plans explicitly incorporates not only the type and size of any new generating facility, but also a particular demand-side management (DSM) program and renewable portfolio. In so doing, pursuing DSM was placed on equal footing with power plant construction as a means of providing safe, reliable, and efficient energy services at just and reasonable rates over the course of the IRP horizon. As previously described, AmerenUE developed and analyzed three DSM initiatives (aggressive, moderate, and nonexistent) in the strategy selection phases of the IRP process. Of note, the top 18 resource plans subjected to risk analysis all adopted the aggressive DSM program. The compelling evidence provided in the responses to sections (1) and (5) of this rule substantiate the preferred status of the NUC1600-Agg-LowNoWind resource plan.

4 CSR 240-22.010 (2) (B)

Use minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan; and

The analyses in the preceding sections of this rule are based squarely upon minimizing either the PVRR or the maximum potential regret, quantified in terms of the plan's difference in PVRR from the lowest-PVRR plan in each end state of the probability tree.

4 CSR 240-22.010 (2) (C)

Explicitly identify and, where possible, quantitatively analyze any other considerations which are critical to meeting the fundamental objective of the resource planning process, but which may constrain or limit the minimization of the present worth of expected utility costs. … These considerations shall include but are not necessarily limited to, mitigation of –

1. *Risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans.*

As laid out in the response to section 4 CSR 240-22.030 (7), AmerenUE devised an analytical framework that allowed a comprehensive evaluation of the uncertain factors critical to resource plan performance. By defining probability distributions across what AmerenUE decision makers deemed reasonably likely ranges of the three scenario and four independent critical uncertainties, the final probability tree explicitly acknowledges the risks of swings in, say, CO_2 policy direction or capital costs. Moreover, the response to section 4 CSR 240-22.070 (8) identifies the two critical uncertainties (namely, CO_2 policy and capital costs) for which there is value in acquiring better information. For these uncertainties, the NUC-1600-Agg-LowNoWind resource plan is not the least-cost option across all parameters. Therefore, if information tracking systems detect persistent movements in CO_2 policy or capital costs towards states where NUC-1600-Agg-LowNoWind is no longer preferred, AmerenUE should consider executing a contingency plan. By monitoring these sensitive variables over time and having next-best contingency plans in place, AmerenUE dampens the risk of higher system costs.

2. *Risks associated with new or more stringent environmental laws or regulations that may be imposed at some point within the planning horizon; and*

The responses to section 4 CSR 240-22.040 (2) (B) explain how CO_2 policy is the only environmental issue that AmerenUE expects to effect significant changes in utility rates within the IRP horizon. Once sensitivity analysis demonstrated that key IRP inputs were sensitive to CO_2 policy assumptions, AmerenUE subject matter experts developed four potential worlds into which CO_2 policy might reasonably evolve - the final probability tree included these CO_2 policy directions. As such, the risk of more stringent environmental policy in the form of CO_2 legislation was treated in the same fashion as every other critical uncertain factor.

3. *Rate increases associated with alternative resource plans.*

The annual average rates for the top eighteen plans were calculated and plotted. The responses to section 4 CSR 240-22.060 (6) (C) 8 has the plots. As discussed above, the compelling evidence provided in the responses to sections (1) and (5) of this rule substantiate the preferred status of the NUC1600 Agg LowNoWind resource plan. In addition, the top eighteen plans all included the Aggressive DSM portfolio. Since the top plans have the same DSM savings, the lowest PVRR will result in the lowest average rates.

(B) The trend of expected unserved hours for the preferred resource plan must not indicate a consistent increase in the need for emergency imported power over the planning horizon.

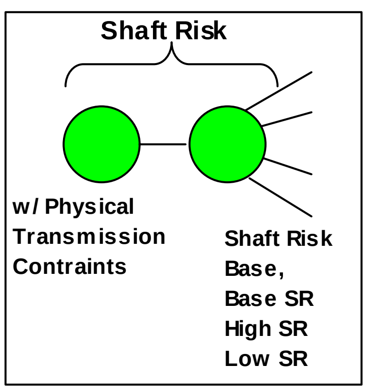
4 CSR 240-22.040 (7) discuss the emergency imports and unserved hours analysis. The conclusion of the analysis is that the preferred plan does not indicate an increase in the need for emergency imported power over the planning horizon.

4 CSR 240-22.070 (7)

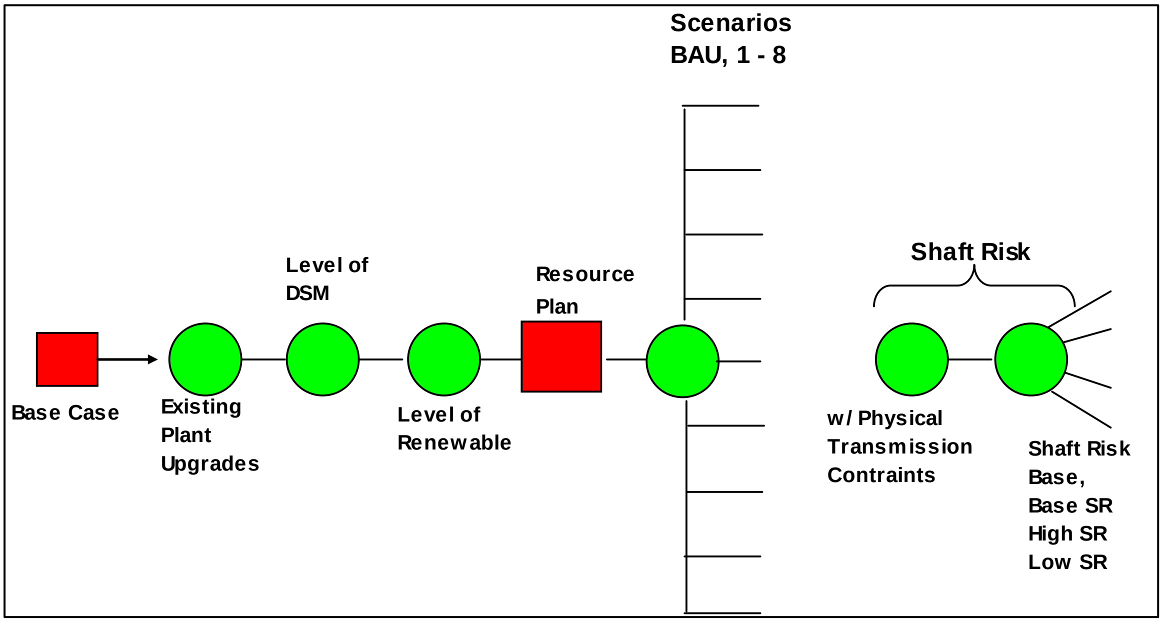
The impact of the preferred resource plan on future requirements for emergency imported power shall be explicitly modeled and quantified. The requirement for emergency imported power shall be measured by expected unserved hours under normal-weather load conditions.

A shaft risk analysis was performed to document the impact that a randomly-occurring random-duration full forced outage would have on the AmerenUE system for the each of the alternative resource plans versus the de-rate method used in the model for all runs, including the independent uncertain factor EFOR. Outage frequency and outage duration values were used in the MIDAS model instead of the EFOR percentages supplied by the various sources.

The impact of random-frequency and random-duration equivalent full forced outages was analyzed for new resources as well as for existing resources.   Two separate sets of studies were developed to test the case when off-system sales would be unlimited and another set of studies to test using physical constraints that result in a 20% reduction in off-system sales.

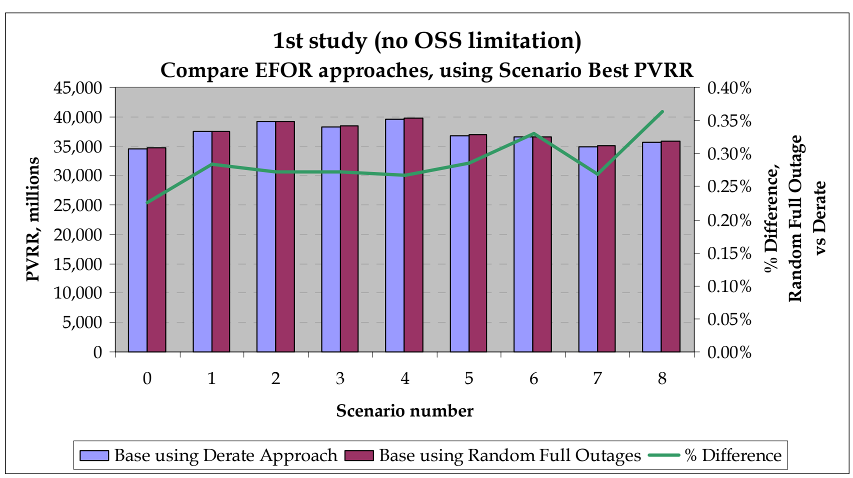


Shaft Risk nodes created to test with top 18 resource plans.



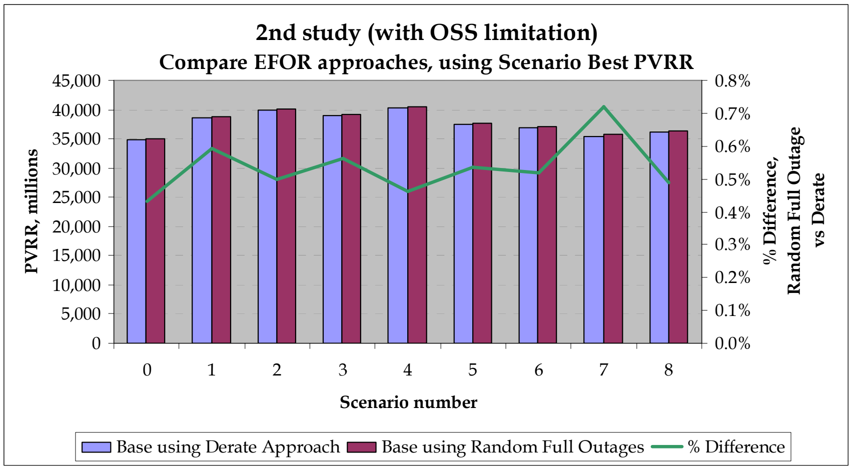
Generic Example of a study used to test Shaft Risk with physical transmission constraints.

The first step of the analysis was to confirm that the results using the random full outage approach to EFOR were equivalent with results using the derate approach to EFOR. This comparison was made by using Base values of independent uncertain factors for the two approaches to EFOR modeling. The comparison of the two EFOR approaches was made twice, once for the first study that did not have an OSS (off-system sales) limitation, and secondly for the second study that did have an OSS limitation.



The nearby chart titled "*1st study (no OSS limitation)*" shows results from these two EFOR approaches for the first set of studies, the ones without any OSS limitations. A blue bar shows the results for the derate approach to Base EFOR, while a maroon bar shows the results for the random full outage approach to Base EFOR, with the relevant axis for these bars shown on the lefthand side.

These bars are virtually the same size across the 9 scenarios, meaning the two Base EFOR approaches are equivalent. A closer look at how equivalent they are can be determined by examining the percent difference between them, which is shown by a green line whose axis is on the righthand side. The fact that the bars for each scenario for the two approaches are only generally around 0.25% to 0.4% different means that the two approaches, derate and random full outage, produce equivalent results when there is no OSS limitation.



The nearby chart titled "*2nd study (with OSS limitation)*" shows results from these two Base EFOR approaches for the second set of studies. A blue bar shows the results for the derate approach to Base EFOR, while a maroon bar shows the results for the random full outage approach to Base EFOR, with the relevant axis for these bars shown on the lefthand side.

These bars are virtually the same size across the 9 scenarios, meaning the two Base EFOR approaches are equivalent. A closer look at how equivalent they are can be determined by examining the percent difference between them, which is shown by a green line whose axis is on the righthand side. The fact that the bars for each scenario for the two approaches are only generally around 0.45% to 0.7% different means that the two approaches, derate and random full outage, produce equivalent results when there is an OSS limitation.

The next step was to compare the PVRRs for the top 18 resource plans to the scenario best PVRR. This comparison was done 3 times, using Base, High, and Low values for each plan versus the scenario best PVRR. Differences versus the scenario best PVRR for each plan were multiplied by the appropriate scenario weights and summed to create an expected value of difference versus the best PVRR for each of the top 18 resource plans, for the Base, High, and Low values for the random full outage data. Ranking of the 18 plans was done based on this expected value, separately for Base, High, and Low values. Several tables below show this process for the Base set of values compared to the best in scenario, for the first study which had no OSS limitation:

First study's best PVRRs by scenario, and PVRRs by plan using Base values

Min of PVRR	ScenarioNum								
Level	0	1	2	3	4	5	6	7	8
Base, using random full outage approach	34,673	37,616	39,233	38,381	39,727	36,931	36,678	35,062	35,825

Min of PVRR		ScenarioNum								
Level	PlanName	0	1	2	3	4	5	6	7	8
Base, using Random Full Outage approach	Coal425W/OCCS-Agg-Moderate	35,070	39,192	40,426	39,531	40,803	37,375	36,918	35,522	35,865
	Coal425W/OCCS-Agg-no	34,673	39,563	40,654	39,744	40,969	37,275	36,678	36,575	36,587
	Coal850W/OCCS-Agg-Moderate	34,933	38,998	40,352	39,357	40,699	37,249	36,855	35,522	35,865
	Combine Cycle-Agg-LowNoWind	34,915	39,414	40,446	39,587	40,914	37,277	36,683	36,133	36,284
	Combine Cycle-Agg-Moderate	35,016	39,173	40,308	39,457	40,692	37,323	36,809	35,522	35,865
	NUC1200-Agg-High	35,900	37,850	39,487	38,691	40,039	37,380	37,332	35,062	36,198
	NUC1200-Agg-LowW/Wind	35,153	38,461	39,827	38,916	40,258	37,173	36,851	36,408	37,003
	NUC1200-Agg-Moderate	35,282	37,967	39,470	38,599	39,938	37,063	36,848	35,531	36,395
	NUC1200-Agg-no	35,069	38,584	39,912	38,964	40,306	37,174	36,804	36,600	37,152
	NUC1200-Agg-Wind	35,750	38,173	39,729	38,916	40,254	37,420	37,280	35,710	36,670
	NUC1600-Agg-High	36,111	37,616	39,337	38,607	39,958	37,411	37,472	35,236	36,547
	NUC1600-Agg-LowNoWind	35,184	37,771	39,304	38,391	39,732	36,931	36,751	36,152	37,021
	NUC1600-Agg-LowW/Wind	35,312	38,095	39,593	38,711	40,045	37,137	36,921	36,458	37,252
	NUC1600-Agg-Moderate	35,430	37,637	39,233	38,381	39,727	37,018	36,919	35,575	36,591
	NUC1600-Agg-no	35,222	38,213	39,673	38,758	40,090	37,133	36,868	36,684	37,398
	NUC1600-Agg-Wind	35,923	37,865	39,514	38,719	40,064	37,400	37,375	35,740	36,856
	Pumped Storage-Agg-Moderate	35,009	39,153	40,329	39,293	40,657	37,323	36,815	35,507	35,898
	Simple Cycle-Agg-High	35,887	39,173	40,458	39,702	41,011	37,752	37,419	35,149	35,825

First study's differences vs scenario best, multiplied by scenario weights

		0.50%	2.30%	30.55%	2.30%	30.55%	10.90%	10.90%	6.00%	6.00%	100.00% <--Scen Wts	
Level	PlanName	Part_0	Part_1	Part_2	Part_3	Part_4	Part_5	Part_6	Part_7	Part_8	EV_BSR_Diff	Rank on EV BSR Diff
Base, using Random Full Outage approach	Coal425W/OCCS-Agg-Moderate	2	36	365	26	329	48	26	28	2	863	15
	Coal425W/OCCS-Agg-no	0	45	434	31	380	37	0	91	46	1,064	18
	Coal850W/OCCS-Agg-Moderate	1	32	342	22	297	35	19	28	2	778	14
	Combine Cycle-Agg-LowNoWind	1	41	371	28	363	38	1	64	28	934	16
	Combine Cycle-Agg-Moderate	2	36	329	25	295	43	14	28	2	773	13
	NUC1200-Agg-High	6	5	78	7	95	49	71	0	22	334	5
	NUC1200-Agg-LowW/Wind	2	19	181	12	162	26	19	81	71	574	10
	NUC1200-Agg-Moderate	3	8	72	5	64	14	19	28	34	248	3
	NUC1200-Agg-no	2	22	207	13	177	26	14	92	80	634	11
	NUC1200-Agg-Wind	5	13	151	12	161	53	66	39	51	551	9
	NUC1600-Agg-High	7	0	32	5	71	52	87	10	43	307	4
	NUC1600-Agg-LowNoWind	3	4	22	0	2	0	8	65	72	175	2
	NUC1600-Agg-LowW/Wind	3	11	110	8	97	23	26	84	86	447	7
	NUC1600-Agg-Moderate	4	0	0	0	0	9	26	31	46	117	1
	NUC1600-Agg-no	3	14	135	9	111	22	21	97	94	505	8
	NUC1600-Agg-Wind	6	6	86	8	103	51	76	41	62	438	6
	Pumped Storage-Agg-Moderate	2	35	335	21	284	43	15	27	4	765	12
	Simple Cycle-Agg-High	6	36	374	30	392	90	81	5	0	1,014	17

(highlighted in blue), and summed to an expected value of differences versus scenario best PVRR, using Base values (in yellow-highlighted column). In the next column to the right, highlighted in green, is the rank using the expected value of differences versus the scenario best.

For the first study, which had no OSS limitation, a summary of the Base, High, and Low results for the top 18 resource plans are shown in the nearby table below, in rank order. The expected value of differences vs. the scenario best PVRR is shown first, then the rank of each plan is shown on this expected value of differences versus the best in scenario.

Summary in rank order

	EV of diffs vs best in scenario			Rank on Ev of diffs vs best in scenario		
Plan name	Base	High	Low	Base	High	Low
NUC1600-Agg-Moderate	117	808	-366	1	1	1
NUC1600-Agg-LowNoWind	175	870	-309	2	2	2
NUC1200-Agg-Moderate	248	906	-229	3	3	3
NUC1600-Agg-High	307	1,005	-162	4	5	4
NUC1200-Agg-High	334	999	-130	5	4	5
NUC1600-Agg-Wind	438	1,131	-43	6	6	6
NUC1600-Agg-LowW/Wind	447	1,136	-39	7	7	7
NUC1600-Agg-no	505	1,193	19	8	8	8
NUC1200-Agg-Wind	551	1,207	76	9	9	9
NUC1200-Agg-LowW/Wind	574	1,232	97	10	10	10
NUC1200-Agg-no	634	1,292	157	11	11	11
Pumped Storage-Agg-Moderate	765	1,322	319	12	12	12
Combine Cycle-Agg-Moderate	773	1,330	330	13	13	14
Coal850W/OCCS-Agg-Moderate	778	1,346	327	14	14	13
Coal425W/OCCS-Agg-Moderate	863	1,425	419	15	15	15
Combine Cycle-Agg-LowNoWind	934	1,487	492	16	16	16
Simple Cycle-Agg-High	1,014	1,562	573	17	17	17
Coal425W/OCCS-Agg-no	1,064	1,616	618	18	18	18

The conclusion from these results for the first study is that when using the random full outage approach to EFOR, with no OSS limitation, there is no impact on plan rankings regardless of whether Base, High, or Low values are used for the analysis. This is evident from the last 3 columns in the above table, showing the same rank for each plan regardless of whether Base, High, or Low values were used, despite changes in the expected values on which the ranks are based.

The second study was analyzed the same way as the first study. For the second study, which had an OSS limitation, a summary of the Base, High, and Low results for the top 18 resource plans are shown in the nearby table below, in rank order. The expected value of differences vs. the scenario best PVRR is shown first, then the rank of each plan is shown on this expected value of differences versus the best in scenario.

Summary in rank order

	EV of diffs vs best in scenario			Rank on Ev of diffs vs best in scenario		
Plan name	Base	High	Low	Base	High	Low
NUC1600-Agg-LowNoWind	194	768	-172	1	1	1
NUC1200-Agg-Moderate	256	790	-105	2	2	2
NUC1600-Agg-Moderate	283	832	-69	3	3	3
NUC1600-Agg-no	432	1,011	52	4	9	4
NUC1600-Agg-LowW/Wind	438	1,009	66	5	7	7
NUC1200-Agg-LowW/Wind	439	990	59	6	4	5
NUC1200-Agg-no	450	1,009	64	7	8	6
Pumped Storage-Agg-Moderate	523	994	154	8	5	8
Combine Cycle-Agg-Moderate	525	997	161	9	6	9
NUC1200-Agg-High	581	1,096	253	10	11	11
Combine Cycle-Agg-LowNoWind	602	1,085	227	11	10	10
Coal850W/OCCS-Agg-Moderate	638	1,100	281	12	12	12
Coal425W/OCCS-Agg-Moderate	650	1,118	294	13	13	13
NUC1200-Agg-Wind	663	1,187	313	14	14	14
Coal425W/OCCS-Agg-no	742	1,224	363	15	15	15
NUC1600-Agg-Wind	756	1,295	418	16	16	16
NUC1600-Agg-High	804	1,322	496	17	18	17
Simple Cycle-Agg-High	869	1,321	519	18	17	18

The conclusion from these results for the second study is that when using the random full outage approach to EFOR, with an OSS limitation, there is only a minimal impact on plan rankings regardless of whether Base, High, or Low values are used for the analysis. This is evident from the last 3 columns in the above table, showing nearly the same rank for each plan regardless of whether Base, High, or Low values were used, despite changes in the expected values on which the ranks are based.

Comparing rank order results from the first study with those from the second study, the top plans generally stay on top, as shown in the table below.

Rank on EV of diff vs scen best	Study#1, no OSS limit			Study #2, with OSS limit		
Plan name	Base	High	Low	Base	High	Low
NUC1600-Agg-Moderate	1	1	1	3	3	3
NUC1600-Agg-LowNoWind	2	2	2	1	1	1
NUC1200-Agg-Moderate	3	3	3	2	2	2
NUC1600-Agg-High	4	5	4	17	17	17
NUC1200-Agg-High	5	4	5	10	10	10
NUC1600-Agg-Wind	6	6	6	16	16	16
NUC1600-Agg-LowW/Wind	7	7	7	5	5	5
NUC1600-Agg-no	8	8	8	4	4	4
NUC1200-Agg-Wind	9	9	9	14	14	14
NUC1200-Agg-LowW/Wind	10	10	10	6	6	6
NUC1200-Agg-no	11	11	11	7	7	7
Pumped Storage-Agg-Moderate	12	12	12	8	8	8
Combine Cycle-Agg-Moderate	13	13	14	9	9	9
Coal850W/OCCS-Agg-Moderate	14	14	13	12	12	12
Coal425W/OCCS-Agg-Moderate	15	15	15	13	13	13
Combine Cycle-Agg-LowNoWind	16	16	16	11	11	11
Simple Cycle-Agg-High	17	17	17	18	18	18
Coal425W/OCCS-Agg-no	18	18	18	15	15	15

4 CSR 240-22.070 (7) (A)

The daily normal-weather series used to develop normal-weather loads shall contain a representative amount of day-to-day temperature variation. Both the high and low extreme values of daily normal-weather variables shall be consistent with the historical average of annual extreme temperatures.

Normal weather was estimated using rank and order methodology to capture the extreme coldest and hottest conditions. The steps used to estimate normal weather are:

- Average the daily high and low temperatures for the time period that span 1971-2000.
- Calculate daily HDD’s and CDD’s.
- Sort HDD’s from highest to lowest for each year.
- Sort CDD’s from highest to lowest for each year.
- Calculate the average of HDD’s for each rank across the years.
- Calculate the average of CDD’s for each rank across the years.
- Map the calculated normal degree days to actual calendar weather making sure that the monthly maximum/minimum degree days fall on week days.

For mapping the estimated normal degree-days into the forecast period, a typical HDD and CDD weather pattern is calculated from thirty-years of historical daily degree days over the period 1971 to 2000. The typical weather pattern is calculated by averaging actual daily degree-days by date (i.e., all the January 1st‘s are averaged, the January 2nd’s are averaged, …, December 31st‘s are averaged). Then, normal degree-days calculated using the rank and average method are mapped to the typical weather pattern. The highest degree-day from the normal degree-days is mapped to the highest degree-day in the calculated typical daily weather pattern; the second highest degree-day is mapped to the second highest degree-day, and so on.

4 CSR 240-22.070 (7) (B)

The supply-system simulation software used to calculate expected unserved hours shall be capable of accurately representing at least the following aspects of system operations:

1. Chronological dispatch, including unit commitment decisions that are consistent with the operational characteristics and constraints of all system resources;

2. Heat rates, fuel costs, variable operation and maintenance costs, and sulfur dioxide emission allowance costs for each generating unit;

3. Scheduled maintenance outages for each generating unit;

4. Partial- and full-forced-outage rates for each generating unit; and

5. Capacity and energy purchases and sales, including the full spectrum of possibilities, from long-term firm contracts or unit participation agreements to hourly economy transactions.

A. The utility shall maintain the capability to model purchases and sales of energy both with and without the inclusion of sulfur dioxide emission allowances.

B. The level of energy sales and purchases shall be consistent with forecasts of the utility's own production costs as compared to the forecasted production costs of other likely participants in the bulk power market; and

The responses to section 4 CSR 240-22.060 (6) (E) has a description of the computer models used for the supply-side simulation software. The software meets all the specifications listed above.

4 CSR 240-22.070 (7) (C)

(C) The utility may use an alternative method of calculating expected unserved hours per year if it can demonstrate that the alternative method produces results that are equivalent to those obtained by a method that meets the requirements of subsection (7)(B).

AmerenUE did not use an alternative method; AmerenUE used a method that meets the requirements for subsection (7) (B).

4 CSR 240-22.070 (8)

The utility shall quantify the expected value of better information concerning at least the critical uncertain factors that affect the performance of the preferred resource plan, as measured by the present value of utility revenue requirements.

The methodology adopted to determine the expected value of perfect information (EVPI)[1] for each of the three scenario uncertainties and the four critical independent uncertainties comprising the probability tree followed standard decision analysis protocols. In general, the EVPI represents the maximum dollar value AmerenUE should be willing to spend on programs designed to eliminate uncertainty around each of the IRP uncertainties, *given that it has selected a certain resource plan*. Under conditions of risk neutrality, since AmerenUE is ranking resource plans giving heavy emphasis to the present value of revenue requirements (PVRR), this EVPI can be thought of as the difference in expected PVRR with and without perfect information about the variable under consideration. Put differently, where x is the uncertain variable, the EVPI is given by:

$$\text{EVPI}(x) = \text{EV (PVRR | Uncertainty)} - \text{EV (PVRR | Perfect Information about } x\text{)}$$

Below is an illustrative example intended to clarify how this process was structured, followed by a discussion of how this simplified approach was extrapolated across the full range of alternative resource plans, scenarios, and critical independent uncertainties.

Representative Example

In this simple example, consider a situation in which there are only two candidate plans against which to evaluate removing uncertainty around CO_2 policy, and which only includes outcomes with no renewable portfolio and an aggressive DSM program. In addition, assume that the uncertainty in CO_2 policy is fully represented by Scenario 4 (High CO_2) and Scenario 6 (Moderate CO_2) from the probability tree, to which fictitious subjective probabilities of 70% and 30%, respectively, are assigned. The PVRR, in millions of dollars, of the NUC1200 and Combined Cycle (CC) resource plans in each of these scenarios is given in Table 1 below.

[1] EVPI is the expected value of better information where the information quality moves from the uncertainty defined by the probabilistic outcomes for each critical uncertainty to the 100% certainty of a given critical uncertainty.

Table 1: PVRR of NUC1200 and Combined Cycle Resource Plans in Scenarios 4 and 6 ($ Millions).

	NUC1200	Combined Cycle
Scn 4 (High CO_2)	$40,438	$41,222
Scn 6 (Moderate CO_2)	$36,886	$36,867

AmerenUE seeks to identify the plans with the minimum PVRR across each endpoint (or scenario, in this simplified example) in the probability tree. By this measure, the NUC1200 build plan of Table 1 would be preferred in the High CO_2 price scenario, while the Combined Cycle plan would be preferred in the Moderate CO_2 price scenario. Because different resource plans are best suited for each scenario, there is value in knowing what CO_2 prices will actually materialize, if such information would be possible to obtain before the choice between the NUC1200 and Combined Cycle plans must be finalized. Depending upon what is learned from the ongoing research or information tracking of CO_2 prices, different alternative resource plans might be preferred.

The first step is to compute the expected value of each resource plan without perfect information about CO_2 prices. That is, what is the probability-weighted average PVRR of each resource plan given that AmerenUE does not know with certainty whether CO_2 prices will be high (Scenario 4) or moderate (Scenario 6)? Figure 1 graphically depicts this decision process.

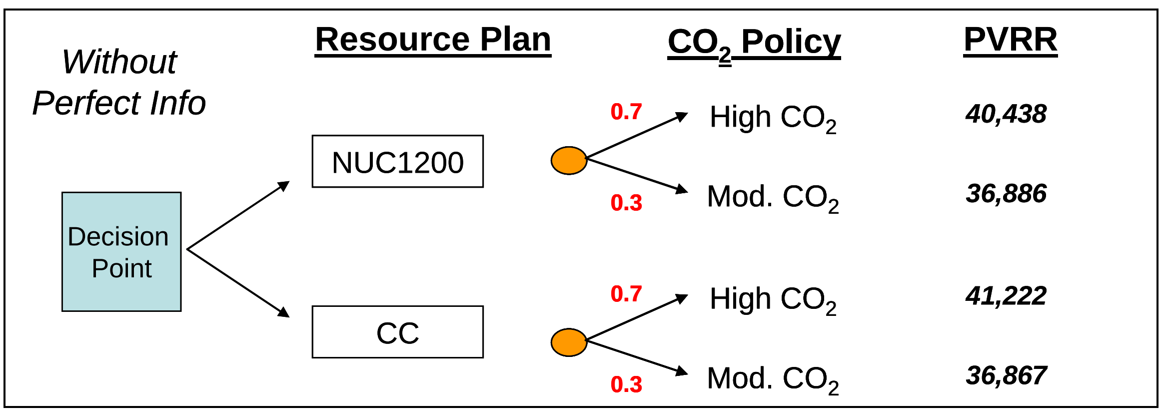


Figure 1: Decision Process without Perfect Information about CO_2 Prices.

Given the CO_2 probabilities in the flow diagram above, one can calculate an expected value of the PVRR for both the NUC1200 and Combined Cycle resource plans, given by <NUC1200> and <CC>, where

<NUC1200> = 0.7 x 40,438 + 0.3 x 36,886 = 39,372, and

<CC> = 0.7 x 41,222 + 0.3 x 36,867 = 39,916.

In this uncertain situation, the option with the lowest <u>expected</u> PVRR is NUC1200, so (absent consideration of risk aversion or other decision criteria) AmerenUE would choose NUC1200 over Combined Cycle for its plan, and have an expected PVRR of $39,372 million.

The landscape changes if AmerenUE were to acquire perfect information as to whether CO_2 prices will be high or moderate *prior to having to commit to a decision*. With this perfect information, AmerenUE would simply select the resource plan with the lower PVRR in each CO_2 price world. This inverted decision process is presented in Figure 2.

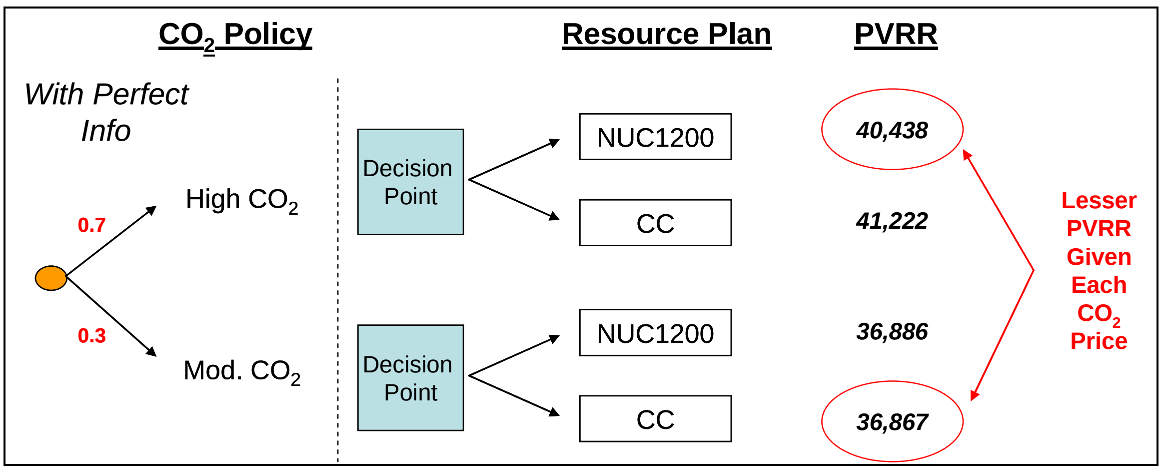


Figure 2: Decision Process with Perfect Information about CO_2 Prices.

Figure 2 reveals that if AmerenUE knew with certainty that there would be high CO_2 prices, it would optimally choose the NUC1200 resource plan because it has a lower PVRR than the Combined Cycle resource plan (40,438 < 41,222). Conversely, if moderate CO_2 prices were to occur with certainty, then AmerenUE would opt to pursue the CC resource plan (36,867 < 36,886). Using the CO_2 price probabilities as weights on the so-determined optimal plans, one can calculate the expected value of PVRR given perfect information about CO_2 prices (<PVRR | CO_2 Perfect Information>) as follows:

<PVRR | CO_2 Perfect Information> = 0.7 x 40,438 + 0.3 x 36,867 = 39,367.

Note that this is less than the expected PVRR of making the less informed decision to build NUC1200 (*i.e.*, \$39,372 million).[2]

For each alternative resource plan, AmerenUE should be willing to invest up to the difference between the expected PVRR without perfect information and the expected PVRR with perfect information in order to completely eliminate uncertainty around CO_2 policy (if this were possible). That is, the EVPI given that AmerenUE would select the NUC1200 resource plan in the absence of that information is:

EVPI (CO_2 policy outcome) = <NUC1200> - <PVRR | CO_2 Perfect Information>

= 39,372 - 39,367 = \$5 million.

Thus, if AmerenUE initially selects, but has not yet financially committed to, the NUC1200 alternative resource plan, it should be willing to spend a maximum of \$5 million to obtain perfect information about future CO_2 prices.

Generalization

AmerenUE identified 18 alternative resource plans to subject to further risk and EVPI analysis. For each of these resource plans, AmerenUE analyzed four critical independent uncertainties (three sets of capital costs, three sets of interest rates, two sets of off-system sales, and two renewable production tax credits) across the nine scenarios to produce 324 PVRR outcomes weighted by the subjective probabilities in the IRP tree. For the three coal-based resource plans, the PVRR outcomes from the combined cycle resource plan with similar renewable portfolio and demand-side management assumptions were substituted in scenarios 7 and 8, since coal-based resource plans were explicitly not allowed in these scenarios. This data formed the backbone of the EVPI analysis.

The expected PVRR without perfect information was computed by multiplying each outcome by the joint probability of the three scenario and four independent uncertainties, and then summing over the 324 endpoints of each resource plan. Consistent with the results presented in Table 1 of the response to section 4 CSR 240-22.070 (5) (A), the second column in Figure A-4 of 4 CSR 240-22.070 Appendix A shows that the alternative resource plan with

[2] If the NUC1200 resource plan were preferred in each possible world, there would be no change in the expected PVRR with and without perfect information, and therefore no value in obtaining better information.

lowest expected PVRR (equal to $39,221 million) under complete uncertainty is NUC1600-Agg-LowNoWind.

Where the actual approach differed most from the simple example described above is in the computation of the expected PVRR given perfect information. In place of the deterministic PVRRs at the far right of Figure 2, AmerenUE calculated the expected PVRR of each resource plan *across all the remaining uncertainties, given that one parameter of the certain variable had occurred.* For example, consider the situation in which AmerenUE is analyzing the value in acquiring perfect information around natural gas prices. For each top resource plan, AmerenUE computed an expected PVRR across the two other tree uncertainties (CO_2 policy and load growth) and the four critical independent uncertainties, *assuming that either high or base natural gas prices have already materialized.* Figure 3 below presents a flow diagram, similar to those in the preceding example, which illustrates how the expected PVRR with perfect information around natural gas prices was derived.

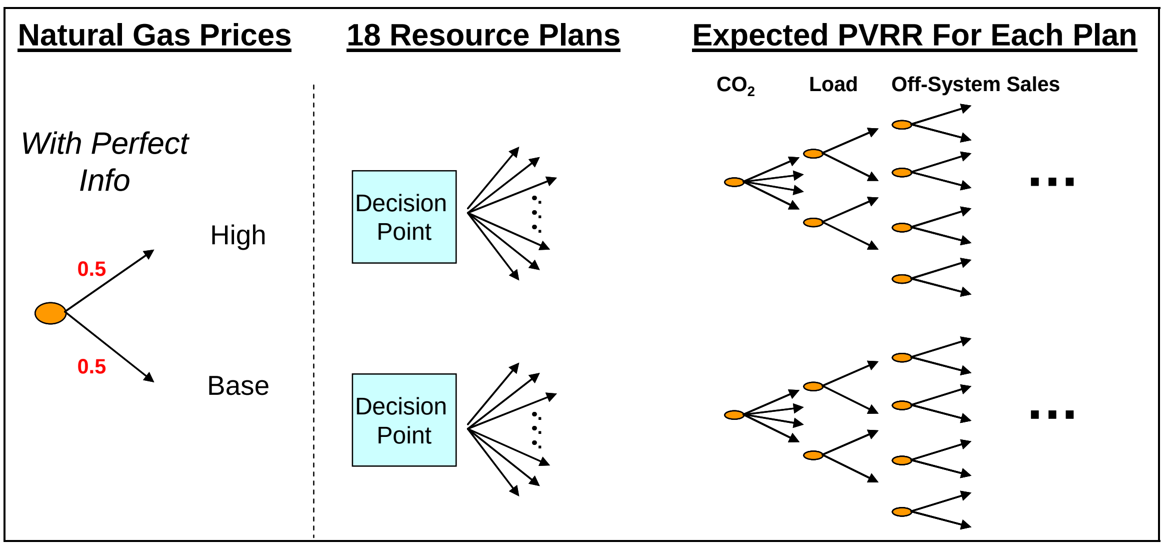


Figure 3: Deriving the Expected Value of Perfect Information about Natural Gas Prices.

Figure A-4 in 4 CSR 240-22.070 Appendix A tabulates the EVPI for each of the scenario and critical independent uncertainties. Under risk neutrality, there is value in obtaining better information for only two of the uncertainties: (1) CO_2 policy, equal to $149 million, and (2) capital costs, equal to $16 million. What does this mean, in the case of capital costs, for instance? Prior to financially committing to the preferred resource plan, AmerenUE should be willing to invest up to $16 million in better tracking the market drivers (*e.g.*, steel and raw materials prices) of power plant capital costs.[3] No “value” was found for reducing the remaining uncertainties, because the NUC1600-Agg-LowNoWind option had the lowest expected PVRR both under complete uncertainty *and* with perfect information that each parameter of that variable had occurred. This is simply due to having erred on the side of inclusion in identifying the “critical” uncertainties in the probability tree. For the two uncertainties with a nonzero EVPI, however, AmerenUE has developed contingency plans that trigger the implementation of resource plans different than the NUC1600-Agg-LowNoWind option, should, for instance, high capital costs eventuate.

[3] A more intuitive way to think about the EVPI for capital costs is that AmerenUE should be willing to pay up to $16 million to lock in “base” fixed capital charges that would avert the possibility, however small (10%), that high market-based capital costs would materialize.

4 CSR 240-22.070 (9)

(9) The utility shall develop an implementation plan that specifies the major tasks and schedules necessary to implement the preferred resource plan over the implementation period. The implementation plan shall contain:

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

As part of the long-term forecast filing, AmerenUE is required to satisfy very specific rules as outlined in the Missouri Electric Utility Resource Planning 4 CSR 240-22.30 Load Analysis and Forecasting section. These rules were established in 1993 when end-use forecasting was generally regarded as the best approach for generating long-term forecasts. Since that time, the long-term forecast methodology has evolved to a less data intensive statistical modeling approach called a Statistically Adjusted End-Use (SAE) model. AmerenUE currently uses the SAE modeling methodology, which has become the industry standard forecasting approach. AmerenUE applied for several variances to the detailed rules because of the reduced data requirements of the SAE approach. Most of those variance requests are anticipated to continue in future filings, as the SAE forecasting methodology is currently envisioned as the forecasting approach of choice for the foreseeable future. Based on this, it appears that much of the more detailed end-use information contemplated by the rules will not be necessary in future filings. However, in order to accurately apply the SAE methodology, it is necessary to have end-use saturation and efficiency data. This type of data is typically acquired through customer surveys that collect information about household demographics and appliance stocks for residential customers and similar appliance stock surveys for commercial customers. Although utility-specific survey information was not available at the time of the 2008 filing, AmerenUE utilized the Missouri state-wide residential saturation survey and end-use data for the West North Central census region developed by the Energy Information Administration. In order to ensure that high quality appliance saturation and efficiency data is available for purposes of executing SAE forecasts, AmerenUE will evaluate implementing utility-specific residential and commercial surveys going forward on a three-year basis. Because this is a potentially costly endeavor that must be evaluated in conjunction with other options, AmerenUE will also explore the possibility of conducting joint surveys with other state utilities and assess the viability of jointly funding further state-wide appliance saturation studies. In addition to providing data to use in the SAE forecast, these surveys will be a valuable part of the load analysis that is likely to be required as a part of the Demand Side Management (DSM) and Energy Efficiency (EE) initiatives that are under development. For that reason, the data requirements of AmerenUE's new DSM and EE programs must be developed further prior to the implementation of any survey plan.

The ability to analyze commercial and industrial customers by the North American Industry Classification System (NAICS) is an integral part of understanding how AmerenUE customers consume electricity. Although AmerenUE currently stores the NAICS code (formerly Standard Industrial Classification, SIC) in its customer information system, there is uncertainty about the completeness, accuracy, and maintenance of the information. AmerenUE will explore the possibility of validating and updating NAICS codes, as well as developing a process to maintain the NAICS codes stored in its customer information system on an on-going basis. Particularly in the design and evaluation of DSM and EE programs for the commercial and industrial sectors, improved NAICS data will be valuable information.

For many of the rules and generally for load analysis work, it is necessary to have load shape and peak load data by customer class. To fulfill this need, AmerenUE currently maintains a load research sample designed to statistically represent its major rate classes: Residential, Small General Service, Large General Service, Small Primary Service, and Large Primary Service. This load research sample is evaluated periodically to ensure that it continues to be representative of AmerenUE's dynamic customer base. There are times when it becomes necessary to select updated samples based on the current population of customers. The type and scope of load research data needed to perform load analysis work will undoubtedly be affected by the evolution of AmerenUE's DSM and EE programs. New DSM and EE programs will require a more detailed analysis of load shapes and may require more detailed customer segmentation within major classes. So in addition to monitoring the load research samples for their continued representation of the customer population, AmerenUE will also need to determine whether its existing sample is sufficient to provide the level of support necessary for these DSM and EE initiatives. As the DSM and EE programs are developed further, the data requirements to support them will become clearer. As this clarity develops, AmerenUE will explore the possibility of redesigning its load research sample and expand its ability to meet the new requirements.

The major tasks and schedule of each of the planned research activities that are described above as means to update and improve the quality of data used in load analysis and forecasting is highly dependent on the needs of AmerenUE's DSM and EE programs. Even the customer appliance and demographic surveys that will be required to support SAE forecasting are also critical components of the load analysis around DSM and EE programs. Currently these programs are under development and specific data needs are not known. Until these DSM and EE data needs are clarified, it would be premature to outline the specific form that surveys and load research sample design will take. Preliminary timelines indicate those requirements will be more explicitly defined by the end of the second quarter of 2008. With the completion of the DSM and EE requirements according to the anticipated schedule, the assessment of all the planned research activities above will be complete by the end of calendar year 2008. According to the results of the assessment, action plans including major tasks and schedules needed to implement the identified enhancements to AmerenUE's load analysis program will also be complete by the end of calendar year 2008.

(B) A schedule and description of ongoing and planned demand-side programs, program evaluations and research activities;

The implementation plan submitted as 4 CSR 240-22.070 (9)_Appendix - DSM Implementation Plan, covers a three year implementation period beginning on June 1, 2008 and extending through May 31, 2011. The plan describes in detail AmerenUEs proposed DSM programs, the research activities conducted to determine the programs and the implementation approach and timeline to bring the programs to the public. AmerenUE did not include evaluations of past programs since such programs have not existed at AmerenUE in the past. 4 CSR 240-22.070 (9)_Appendix - DSM Implementation Plan represents AmerenUE's dedicated launch into the DSM program arena. The table below summarizes the estimated energy and demand savings and costs estimated for this period.

	2008	2009	2010
Estimated energy savings (MWh)	61,918	123,835	269,185
Estimated demand reduction (MW)	53	106	131
Estimated costs (Program costs only)	$13 M	$24.5 M	$31.9 M

Estimated Savings and Costs for the Implementation Period

The Plan represents AmerenUE's commitment to meeting these savings levels and by doing so to enhance the value we deliver for our customers. The Company engaged ICF International, a leader in Demand Side Management consulting services and worked with a diverse group of stakeholders to develop a portfolio of programs that uses best practice program design and delivery to reach all key customer groups with cost-effective energy efficiency options. The portfolio has been crafted to meet clear public policy and corporate objectives, and represents the first step in an ongoing process to offer the best customer energy management services possible to our customers.

The Company's Plan reflects a detailed analysis process that included the economic screening of close to 865 energy efficiency measures, a review of utility program design best practices and a formal uncertainty and risk analysis.

The Company, in cooperation with a broad group of stakeholders, has developed an aggressive portfolio of energy efficiency and demand-response programs as part of its integrated resource plan that will meet these statutory requirements. The portfolio as a whole is cost-effective with a TRC test benefit-cost ratio of 1.71. The portfolio was constructed to offset at least 25% of energy and demand growth by 2016, and achieve a minimum reduction of 230 MW by 2012 and 540 MW by 2025.

The portfolio is built around two broad programs, each of which contains several program elements intended to provide a diverse range of energy efficiency options for all customer classes.

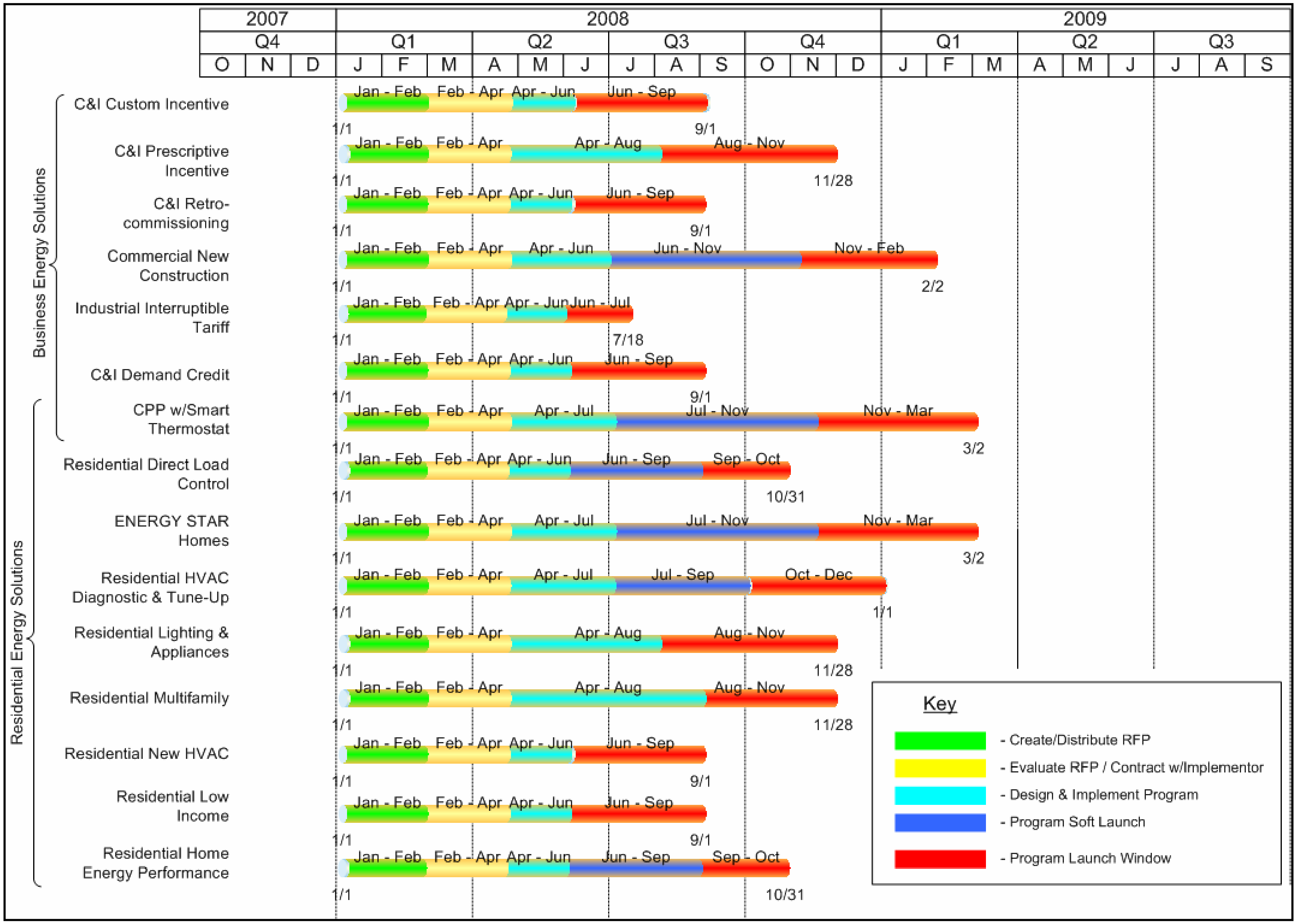
- **Residential Energy Solutions** offers a wide range of options for residential customer energy management. The program is intended to offer customers multiple points of entry to the services offered by the Company, while at the same time promoting comprehensive actions that can create the most value for customers. An important objective of this program is to use customer education, training, and technology to build a foundation for market transformation. During the first implementation cycle, we expect that most program elements will be technology-based and focused on relatively simple customer actions. Coupled with a strong consumer awareness and education effort, our objective is to transform initial technology focused services into more comprehensive "whole home" solutions. The Residential Energy Solutions portfolio includes the following programs:
    - Lighting and appliance rebates
    - Central air conditioner diagnostics and tune-up
    - New central air conditioner proper installation incentives
    - A Multi-Family Program.
    - Home Energy Performance.
    - Web-based residential energy audits.
    - ENERGY STAR Homes Program.
    - Residential Low Income.
    - Direct Load Control
    - Critical Peak Pricing with a Smart Thermostat.

- Business Energy Solutions offers a complementary set of energy management options to commercial and industrial customers. A wide range of Individual technology or device incentives will be available, but the objective of the program over time is to move customers towards comprehensive solutions. Customers will be able to enter the program through any individual program element, although the Company will encourage customers to use building benchmarking services available through the program as a first step toward adoption of a "whole building" perspective on energy management. Specific program elements will include:
    - Prescriptive incentives.

- Custom incentives.
- Retro-Commissioning incentives.
- Commercial New Construction.
- Commercial Demand Credit.
- Industrial Interruptible Tariff.
- Critical Peak Pricing with a Smart Thermostat.

Most programs will be implemented by third party contractors selected by the Company through competitive bid. The Company will explore the use of performance-based contracts that reward cost effective delivery of verified energy savings. The implementation contractors will be responsible for development of final detailed program designs and implementation plans, including all program participation and incentive forms and marketing collateral subject to approval by the Company. In most cases, the contractors will be responsible for customer recruitment, delivery of program services and incentive fulfillment, although the AmerenUE key account representatives will retain the primary relationships with the Company's key accounts. The Company intends to issue requests for proposals (RFP) for programs in early 2008, and to have contracts in-place by May. Implementation contractors will have until the end of June to develop detailed program designs and implementation plans in consultation with the Company. Concurrent with the issuance of RFPs for the implementation contractors, AmerenUE will also issue a separate RFP for an Evaluation, Measurement and Verification (EM&V) contractor. The Company's expectation is to have the EM&V contractor under contract prior to program design since program design and evaluation methodologies are directly linked. The Company intends to launch most programs in the third quarter of 2008.

AmerenUE DSM Program Implementation Plan



(C) A schedule and description of all supply- side resource acquisition and construction activities; and

Major Task and Schedules for Renewable Resources

In conjunction with the IRP process and specific workshops hosted by AmerenUE throughout calendar year 2007 and attended by various stakeholders including staff from the MoPSC, Office of Public Council, Mo DNR and others, the following plan has been developed which lays out the steps to provide for the integration of renewable energy resources into AmerenUE's generation mix.

The overall plan deals with activities that are currently underway and discusses the necessary steps to bring them to completion. It also deals with assessment and evaluation of specific renewable energy technologies, both existing and emerging. The report then concludes with research and development involving distributive generation that utilizes renewable technologies. The specific efforts addressed in this report are those that will be undertaken over the next three years.

In utilizing the renewable energy targets established by SB 54 as the primary objectives to be achieved, 5 specific cases were developed. In the final analysis the "preferred" renewable resource portfolio was demonstrated to be the case that utilized an aggressive DSM plan, coupled with renewable resources focusing on landfill gas, hydro electric, biomass and no additional wind generation required beyond the initial 100 MWs that is currently under negotiation.

The cases developed utilized generic data that represented the capabilities and pricing of renewable technologies. As we continue to evaluate the potentials for this type of generation, AmerenUE intends to expand this analysis to a more precise regional review of the applicable renewable technologies. The specifics related to this are addressed later in this report.

An aggressive DSM plan is reliant upon the ability to change customer behaviors. Due to the inherent uncertainties associated with that effort, AmerenUE will continue to assess the potential of additional wind as a hedge by using data from the 2007 wind RFP. The regulatory uncertainty to potential Federal legislation related to renewable energy requirements, carbon caps and/or green house gas limitations, requires AmerenUE to continually assess and evaluate its means of meeting the primary objectives of SB 54 and the renewable resource portfolio of the preferred plan.

Within the preferred case there are further considerations that may call for AmerenUE to position itself to quickly react to an ever changing renewables market. AmerenUE will need to rely on the willingness of landfill operators to have generation installed at their facilities which may conflict with their core business operations. Run of river hydro is reliant upon permits, the Army Corp of Engineers and the acceptance by the environmental community to allow further development. Further complicating any new generation development is the lengthy time line associated with the construction of new transmission lines. All combined, a proper hedge strategy must be in place to ensure that the targets are achieved.

<u>Renewable - Assessment and Evaluation Activities</u>

Based on the workshop process conducted throughout 2007, a ranking was created that addressed the best regional renewable technologies for consideration. The ranking that was developed, took into consideration the critical factors required for successful development of these various renewable technologies and the ability to successfully bring these generation resources into the mix.

In that regard, AmerenUE will continue to engage industry consultants that are capable of providing specific information related to technology capabilities of renewable resources in the AmerenUE service territory. The goal is to maximize the potential from renewable resources that are best suited to produce energy when considering the specific conditions which exist in the AmerenUE region.

Monitoring the continual technological advancements related to renewable energy generation types will be on going. Based on anticipated development with certain renewable technologies as well as existing renewable energy resource technology, the following lists those generation resources that appear more suited to AmerenUE's territory:

- Wind
- Hydroelectric
- Landfill gas
- Anaerobic Digesters
- Biomass
- Solar

The initial study that was conducted in conjunction with the IRP process of 2007, provided a more general analysis as to the technology rankings. A detailed and comprehensive study will now be required in order to make a determination as to which specific projects related to these technologies should be pursued by AmerenUE and integrated into the generation portfolio.

Projected Timeline:

Develop specific criteria for consulting services	April, 2008
Issuance of RFP for consulting services	May, 2008
Contract with chosen consultant(s)	June, 2008
Begin data accumulation and research	July, 2008
First draft report due	December, 2008
Review and comment period	Jan-Feb, 2009
Revise and finalize report	March, 2009
Issue final report	May, 2009

Wind – Procure 100MWs

As a result of the Request for Proposal (RFP) process that began in 2007, AmerenUE is in the initial phases of negotiating a 20 year 100MW power purchase agreement with Horizon Wind. This negotiation will result in the acquisition of 100 MWs of wind generation from the Rail Splitter Wind Farm that will be owned and operated by Horizon Wind. It is anticipated that negotiations should be concluded by late spring of 2008 with construction of the wind farm slated to begin shortly thereafter. The project should become operational with the delivery of power by early 2009. This will allow AmerenUE to meet its commitment made to the MoPSC that it would have at least 100 MWs of wind energy in its portfolio by 2010.

Projected Timeline:

Power Purchase Agreement negotiations begin:	January, 2008
Conclusion of negotiations:	April, 2008
Contract executed:	April-May, 2008
Construction begins:	May, 2008
Transmission system upgrades:	July, 2008-March, 2009
Power delivery begins:	2nd Quarter, 2009

Wind – Continue to Evaluate Proposals

Additionally, and in conjunction with proposals received under the initial 2007 RFP, analysis is continuing related to other wind projects that were offered to AmerenUE. Several meetings have already been held, with discussions centered on addressing critical transmission issues. These discussions are ongoing and further evaluations are and will be conducted to address project feasibility.

Projected Timeline:	
Follow-up meeting with developer:	January, 2008
Completion of transmission assessment:	March, 2008
Final determination of project feasibility:	April, 2008

Wind - Evaluations Existing AmerenUE Generation Sites

Successful wind farm development is dependent on many items, but the following represent the most critical requirements:

- Wind speeds
- Transmission accessibility
- Land
- Permitting

In an effort to take the benefit of the inherent advantage that AmerenUE may possess related to land availability and ease of permitting, studies will be undertaken to assess wind capabilities at existing AmerenUE generation sites. Wind evaluations will be conducted to determine which sites hold the greatest potential for wind development. Depending on the results of these studies, AmerenUE would then be in a position to develop wind generation at its own sites.

AmerenUE will continue to work with wind developers in the region to ensure that the most efficient and economical wind developments are pursued. The following timetable is proposed for accumulating data and preparing the AmerenUE Renewable Resource Assessment Report.

Project Timeline:	
Procure wind assessment software package	January, 2008
Apply data from specific AmerenUE sites	February, 2008
Evaluate wind potential by site	March, 2008
Install anemometers (if applicable)	April, 2008
MISO transmission capabilities	April-May, 2008
Data collection period	July, 2008-June, 2009
Data evaluation and interpretation	July-September, 2009
Prepare report on recommendations for wind installations	October, 2010
Present findings and recommendations to AmerenUE senior management	November, 2010

Hydroelectric – Upgrades at Existing Plants

AmerenUE will continue to work towards the completion of the turbine maintenance upgrades at its existing hydroelectric generation facilities. (Addressed elsewhere in this IRP filing)

Landfill Gas – Projects

Specific landfill gas operations are also being reviewed at the present time. During the next three years AmerenUE expects to have at least one landfill gas project operational and generating. It is anticipated that generation from one or more of these type projects will yield between 3 to 10 MWs.

Projected Timeline:

Negotiations begin:	February, 2008
LFG consultant hired:	February, 2008
Feasibility study concluded:	March, 2008
Distribution system analysis concluded:	June, 2008
Contract executed:	July, 2008
Construction begins:	August, 2008
Facilities completed:	March, 2009
Energy delivery commences:	2009

Pure Power Program

In June, 2007 AmerenUE launched its voluntary renewable energy program called Pure Power. Under this program, electric customers are given the opportunity to pay an extra $0.015 kWh to procure renewable energy credits (RECs) that AmerenUE purchases from a third party marketing company (3 Degrees) that it has contracted with for both marketing services and REC procurement. This voluntary program allows customers to offset their carbon footprint as it relates to their electric consumption.

Over the next several years, AmerenUE will continue to promote this program to both residential and commercial accounts in an effort to provide for further renewable energy development throughout the State of Missouri.

Educational Development

In October, 2007 AmerenUE launched a renewable energy educational program to 200 schools in its electric service territory. Based on a contract with the National Theatre for Children, educational materials were developed for both teachers and students that explain about energy and renewable energy. In addition, live performances are made to students in grades K-6, providing an entertaining message about "green energy."

As this initial offering has been met with such an overwhelming positive response by the school administration, teachers and students, this program will continue by adding additional schools in the coming 2008-2009 school year with the anticipation to extend this program offering into 2010.

Research and Development

Although solar resources do not appear to possess the efficiency and generation potential or advantage that other renewable resources currently maintain in the region, AmerenUE recognizes that there appears to be rapid growth in its research and technology capabilities. Advancements in wind technology are continuing as well.

In order to stay abreast of these advances that may provide a basis for consideration into the future, AmerenUE will work with regional universities in projects related to renewable development. This program is intended to stimulate the regional development and advancement in educational opportunities as well as potential business growth to the region.

During the time frame covered by this filing, AmerenUE intends to discuss the development of a cooperative program with universities that possess research facilities capable of providing the necessary study and testing that would lead to enhancing the efficiencies of renewable technologies.

To further promote awareness and capabilities of renewable energy technologies and energy efficiency in the region, AmerenUE is working toward LEED certification of the General Office Building located in St. Louis, MO. Solar photovoltaic/thermal and wind are being evaluated with the goal of obtaining LEED points for certification.

Major Task and Schedules for EPR COLA

The construction of the US-EPR is a very major addition to AmerenUE's system. The implementation of the installation of the US-EPR also requires a very long time. While at this point in time, the value of installing the US-EPR appears to be very high with all indications that changes in electric utility industry will only increase that value as time goes on, it is prudent to have an implementation plan that is adaptable as possible to future changes which may negatively affect the value.

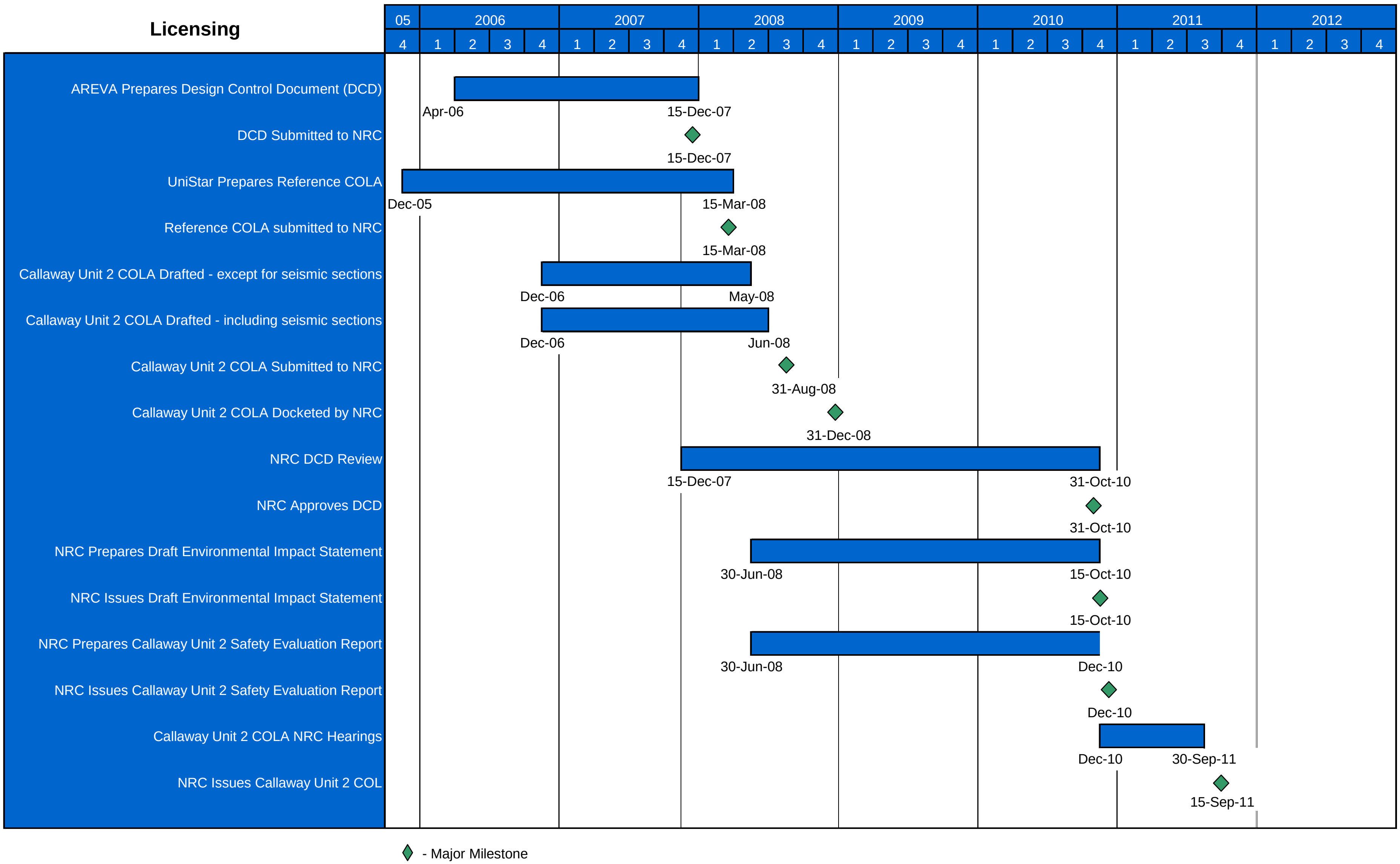
One major contributor to this value is the additional benefits afforded the nuclear option by the Energy Policy Act. A prudent implementation plan includes ensuring that AmerenUE stays qualified for these additional benefits. One of the most significant of these additional benefits is the Production Tax Credits. The Production Tax Credits are based on the first 6,000 MW of new nuclear generation that meets the other requirements. If more than 6,000 MW meets the requirements, then the Production Tax Credits will be prorated among the qualified capacity. Thus one element of the implementation plan is to place the unit into service as early as reasonably possible so that AmerenUE will receive the maximum share of the Production Tax Credits. Another element of the implementation plan is to have the largest unit reasonably possible in order to receive the maximum share of the Production Tax Credit.

After the above general elements are considered, the focus of the implementation plan is on meeting the eligibility requirements of the Energy Policy Act as well as prudent implementation of the project in general. The eligibility requirements to be met are as follows.

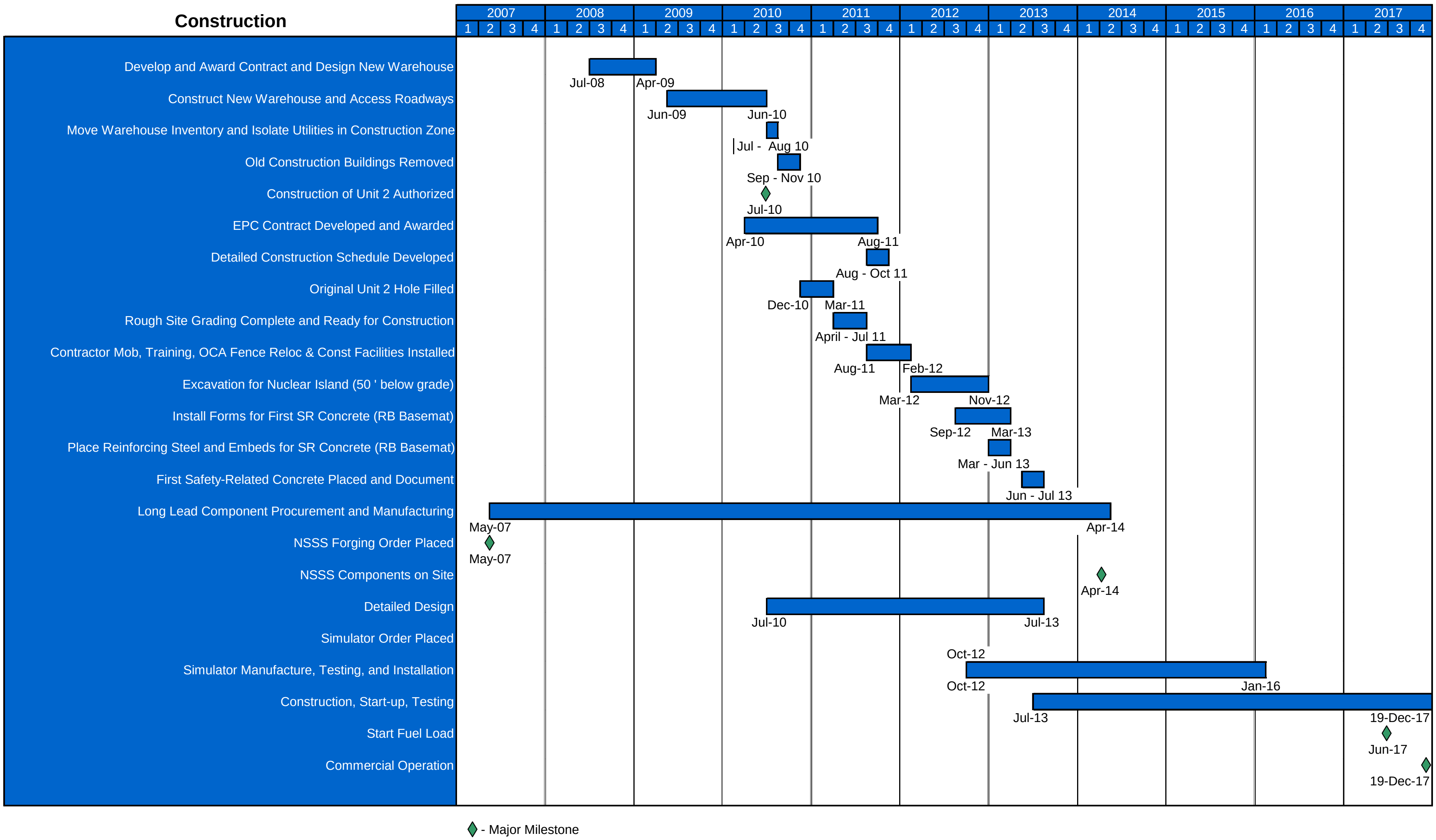
- COLA must be docketed by the NRC by December 31, 2008
- First Safety Related Concrete Pour no later than January 1, 2014
- Commercial operation no later than January 1, 2021

In order to maintain the ability to maximize the Production Tax Credit benefits in conjunction with meeting the overall objectives of providing reliable low cost nuclear energy, AmerenUE has developed the detailed implementation plan presented below.

Implementation Plan - Licensing



Implementation Plan - Construction



Major Task and Schedules for Existing Plants

LP Turbine Replacement

This project involves capital upgrades to the Low Pressure steam turbines at several of the large fossil plants.

- Rush Island Unit 2 - Most likely timeframe for upgrade installation is 2009.
- Rush Island Unit 1 - Most likely timeframe for this upgrade installation is 2012.
- Labadie Unit 2 - Most likely timeframe for this upgrade is 2011.
- Meramec Unit 3 - Most likely timeframe for this upgrade is 2010.

Osage and Keokuk Turbine Replacement

The Keokuk and Osage hydro turbine replacement projects are scheduled according to the following timeline:

- Osage Unit 1 is scheduled for completion during the 2nd quarter of 2008.
- Osage Unit 7 is scheduled for completion during the 2nd quarter of 2008.
- Osage House Units upgrade is scheduled for completion during the 4th quarter of 2009.
- Keokuk Unit 1 upgrade project is scheduled for completion during the 2nd quarter of 2009.
- Keokuk Unit 2 upgrade project is scheduled for completion during the 2nd quarter of 2010.
- Keokuk Unit 3 upgrade project is scheduled for completion during the 2nd quarter of 2009.
- Keokuk Unit 4 upgrade project is scheduled for completion during the 2nd quarter of 2010.
- Keokuk Unit 5 upgrade project is scheduled for completion during the 2nd quarter of 2011.
- Keokuk Unit 6 upgrade project is scheduled for completion during the 2nd quarter of 2011.
- Keokuk Unit 14 upgrade project is scheduled for completion during the 2nd quarter of 2012.
- Keokuk Unit 15 upgrade project is scheduled for completion during the 2nd quarter of 2012.

Electrostatic Precipitator Upgrades

Installation of new power supplies and transformer/rectifier sets on the precipitator controls at the fossil plants has started at Rush Island and Labadie. Procurement and installation of equipment as well as software procurement will continue at Meramec and Sioux plant throughout 2008 and 2009.

Callaway Unit #1 Plant Upgrade

An upgrade to Callaway Unit #1 is being considered and will be studied in greater detail. The extent of the modifications necessary to complete the upgrade is not fully known. A feasibility study needs to be completed before a final determination is made for this upgrade. Below are the major milestones and schedule for completing the feasibility study.

- A Request for Quotes (RFQ) for the feasibility study has been issued.
- Responses to the RFQ are due back by February 11, 2008.
- Issue a contract for the feasibility study in March, 2008.
- The feasibility study is expected to be completed in September, 2008.
- *If the feasibility study shows* this project to be cost justifiable then a RFQ will be issued by October, 2008 for the design/implementation of the upgrade.
- Issue a contract to start the upgrade design/licensing process in January, 2009.
- And finally, implement the upgrade during Refuel 19, currently scheduled for spring 2013.

Venice HRSG Repowering

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. The engineering analysis and design for the HRSG boiler, By-pass damper system, steam turbine-generator and Circulating water system components will most likely start no earlier than 3rd quarter, 2008. It is estimated to require 12-18 months to complete the engineering design. This will be followed by economic analysis estimated to take 6-12 months.

Continued Operation versus Retirement Analysis

The plant under consideration for continued operation and retirement analysis is the Meramec Plant. This plant went into commercial operation in 1953 and is located in South St. Louis County.

With multiple variables affecting the remaining life of a coal fired power plant, an approach was selected that would encompass various issues that require consideration. This approach would outline the process of decision making to be used in the retirement analysis.

Process of Decision Making

- Safety of continued plant operations approaching 70 years in 2021.
- Fuel patterns and availability of fuel for the boilers
- New and revised Environmental regulations at the City, County, State, Federal and International level. Sox, Nox, Hg, 316b, CO2, etc.
- Availability of new confirmed technologies for fossil fuel combustion.
- Utilization of coal combustion by-products and landfill implications.
- National and international resource competition and scheduling of new and upgraded equipment fabrication.
- Condition assessment of the various boiler, turbine and balance of plant components.
- Service and maintenance history reviews.
- Operational and Financial risk assessments.

Retirement Analysis Timeline

- Develop scope of retirement integration items a-i: 4th Quarter 2007
- Develop WBS work plan with activities, responsibilities, and milestones for retirement analysis: 1st Quarter 2008
- Preliminary unit specific Asset Condition & Risk Assessments:3rd Quarter 2008
- Preliminary Decommissioning Impact Analysis: 4th Quarter 08’
- Initial Financial Analysis: 1st Quarter 2009

Major Task and Schedules for Environmental Compliance

The schedule of construction activities for the environmental retrofit projects identified as part of the preferred resource plan described in 4 CSR 240-22.070 (6) are as follows:

Sioux 1 & 2 Wet FGD – Construction began on July 17, 2006 and is scheduled for completion in the fall of 2009. See 4 CSR 240-22.070 Appendix C for the construction schedule.

Halogenated Activated Carbon Injection Systems – Construction has not begun on these systems as it is estimated to take less than one year to construct and the preferred retrofit plan does not call for them at Meramec, Rush Island and Labadie until 2015. Therefore, schedules have not been prepared and will not be provided.

(D) Identification of critical paths and major milestones for each resource acquisition project, including decision points for committing to major expenditures.

Demand- Side Resources

- Most programs will be implemented by third party contractors selected by the Company through competitive bid. The Company will explore the use of performance-based contracts that reward cost effective delivery of verified energy savings.
  - The Company intends to issue requests for proposals (RFP) for programs in early 2008, and to have contracts in-place by May.
  - Implementation contractors will have until the end of June to develop detailed program designs and implementation plans in consultation with the Company.
- Concurrent with the issuance of RFPs for the implementation contractors, AmerenUE will also issue a separate RFP for an Evaluation, Measurement and Verification (EM&V) contractor.
  - The Company's expectation is to have the EM&V contractor under contractor prior to program design since program design and evaluation methodologies are directly linked.
  - The Company intends to launch most programs in the third quarter of 2008.

Renewable Resources

- Renewable Assessment and Evaluation Activities: Issue final report (May, 2009)
- Procure 100MWs Wind
  - Contract executed (April-May, 2008)
  - Power delivery begins (2nd Quarter, 2009)
- Additional Wind: Final determination of project feasibility (April, 2008)

Existing Plant

- Callaway Unit #1 Plant Upgrade – Complete feasibility study (September 2008)
- Venice HRSG Repowering – Complete Engineering Design and Economic Analysis (Fall 2011)
- Continued Operation and Retirement Study – Initial Financial Analysis (1st Quarter 2009)

EPR COLA

In order for AmerenUE to remain eligible for the Nuclear PTC under the Energy Policy Act, the following requirements need to be met:

- COLA must be docketed by the NRC by December 31, 2008
- First Safety Related Concrete Pour no later than January 1, 2014
- Commercial operation no later than January 1, 2021

While maintaining the potential to maximize Production Tax Credits, the implementation plan is designed to accommodate several other elements important to successfully implementing the project. The selection of the US-EPR was based on the appropriate balance between technology advancement and consideration of demonstrated reliability.

The US-EPR at Callaway will be the third unit in the US-EPR construction sequence balancing the early installation with the advantage of other's experience and avoiding first of a kind issues. The construction sequence between units is timed to allow knowledgeable craftsmen and construction oversight personnel, key materials, and specialized construction equipment to be successively leveraged during the major construction phases of each US-EPR. There will be substantial benefits (both financial and schedule related) to maintain the position in this sequence.

The licensing process represents a critical path to implementation. In order to obtain the COL on a schedule to support the objectives of maximizing Production Tax Credits and providing reliable low cost nuclear energy to AmerenUE's system, the DCD and COLA are submitted and reviewed by the NRC in parallel reducing the time required to obtain the COL compared to a sequential approach.

Another important aspect of the implementation plan was the ordering of the NSSS forgings in May 2007. The forging represent a very significant critical path since there is only one manufacturing facility in the world capable of producing the forgings for Callaway 2. The criticality is heightened by the large number of utilities planning nuclear units. By obtaining a spot in the queue AmerenUE both maximizes the benefits of the Production Tax Credits and ensures the successful installation of the unit. While the overall cost of the forgings is significant at [redacted] the payment schedule is such that significant payments are not required until after the COL is issued. Furthermore, with the demand for forgings, there should be a secondary market for the forgings if at some time AmerenUE decides not to pursue the project.

For AmerenUE to remain on schedule to obtain the Nuclear PTC, a decision to proceed with the project needs to be made in late 2010 or early 2011.

Environmental Compliance

Sioux 1 & 2 Wet FGD project – See response to 4 CSR 240-22.070 (9) (C).

Due to the significant amount of time available before construction would need to begin on the halogenated activated carbon injection systems the activity required in this section has not been included.

4 CSR 240-22.070 (10)

The utility shall develop, document and officially adopt a resource acquisition strategy. This means that the utility's resource acquisition strategy shall be formally approved by the board of directors, a committee of senior management, an officer of the company or other responsible party who has been duly delegated the authority to commit the utility to the course of action described in the resource acquisition strategy. The officially adopted resource acquisition strategy shall consist of the following components:

(A) A preferred resource plan selected pursuant to section (6) of this rule;

AmerenUE President and Chief Executive Officer, Tom Voss, has approved the preferred resource plan detailed in 4CSR 240-22.070.6. The letter in the summary document "Integrated Resource Plan Report" states his endorsement.

(B) An implementation plan developed pursuant to the requirements of section (9) of this rule;

AmerenUE's implementation plan is outlined in 4CSR 240-22.070.9.

(C) A specification of the ranges or combinations of outcomes for the critical uncertain factors that define the limits within which the preferred resource plan is judged to be appropriate and an explanation of how these limits were determined;

The responses to sections 4 CSR 240-22.030 (7), 4 CSR 240-22.040 (2) (B) 1- 3, and 4 CSR 240-22.040 (8) (A) explain how the load growth, CO_2 policy, and natural gas price branches of the probability tree were developed. 4CSR 240-22.030(7) Figure 6, 4CSR 240-22.040(2)(B)2 Figure 6, and 4CSR 240-22. 040(8)(A) Figure 27 graphically present the bounds for each of the critical uncertain factors comprising the probability tree. To reiterate, each of these cases reflects a range of values around the given trajectory, from the perspective of how the probability elicitation process was structured. For example the CO_2 policy branches depicted in 4CSR 240-22.040(2)(B)2 Figure 6 do not reject the possibility of 2012 CO_2 prices above $15 or below $5, but instead offer a representative range of politically probable CO_2 trading regimes.

(D) A set of contingency options that are judged to be appropriate responses to extreme outcomes of the critical uncertain factors and an explanation of why these options are judged to be appropriate responses to the specified options; and

As first presented in the response to section 4 CSR 240-22.070 (8), the EVPI analysis provides a roadmap for contingency plan development. First, it bears repeating that the potential for "extreme" outcomes was overtly acknowledged in the creation of a probability tree of critical uncertain factors. The branches developed for each critical uncertain factor were intended to span only a reasonable range of likelihood. Moreover, AmerenUE subject matter experts assigned subjective probabilities to each of these branches; in turn, "extreme" outcomes for critical factors were represented probabilistically. Second, given the tree branches for each critical factor, there is only a need to develop a contingency plan if a resource plan other than the preferred plan under complete uncertainty, NUC1600-Agg-LowNoWind, has the lowest expected PVRR value given perfect information for any "branch" of the uncertain variable. In other words, a contingency plan is only necessary where the EVPI for a particular variable is positive. As Figure A-4 of 4 CSR 240-22.070 Appendix A attests to, this is only true for two of the critical uncertainties, CO_2 policy and capital costs. In fact, the contingency plan itself is simply given by the resource plan with the lowest expected PVRR given perfect information.

The only additional decision-making tool necessary to facilitate contingency plan implementation revolves around <u>when</u> the plan with the lower expected PVRR given certainty about CO_2 policy or capital costs should be triggered. This process is linked to a great extent to the information tracking protocol established in the response to section 4 CSR 240-22.070 (10) (E). Furthermore, the protocol is different depending upon the variable being tracked. In the case of CO_2 policy, the passage (or non-passage) of a national CO_2 cap-and-trade scheme is the clearest signal of what CO_2 world will transpire. If AmerenUE finds itself in any CO_2 realm outside of the "High Price" scenario, then it should consider invoking a contingency schedule around the resource plan with the lowest expected PVRR given in perfect information. Figure A-4 of 4 CSR 240-22.070 Appendix A shows that this contingency resource plan is the Combine Cycle-Agg-LowNoWind plan in the "Moderate Price" world, the Combine Cycle-Agg-Moderate plan in the "Mandates" world, and the Coal425W/OCCS-Agg-no plan in the BAU world. For capital costs, AmerenUE will systematically monitor the precursors and market fundamentals for power plant capital costs. If, within this framework, AmerenUE spots a persistent, sustainable trend towards high capital costs, then the contingency schedule around the Combine Cycle-Agg-LowNoWind resource plan should be pursued. Note that AmerenUE need not wait until it is in a world with high capital costs to commence implementation of this contingency plan.

In the area of environmental retrofits, the contingency options that have been identified are as follows:

> SO_2 – acceleration or delay of the installation dates of SO_2 control technology at its coal facilities, retirement of existing coal facilities to reduce system emissions, and purchase of additional SO_2 allowances if required by regulations for compliance
>
> NOx – acceleration or delay of the installation dates of NOx control technology at its coal facilities, retirement of existing coal facilities to reduce system emissions, and purchase of additional NOx allowances if required by regulations for compliance
>
> Hg – acceleration or delay of the installation dates of Hg control technology at its coal facilities, retirement of existing coal facilities to reduce system emissions, and purchase of additional Hg allowances if required by regulations for compliance
>
> CO_2 – The economics of CO_2 capture is highly uncertain and many issues need to be resolved before storage is a viable option. If all of the issues surrounding the technology are satisfactorily resolved, then the options would the installation of carbon capture and sequestration equipment and associated infrastructure to reduce CO_2 emissions, retirement of existing coal facilities to reduce system emissions, and purchase of additional CO_2 allowances if required by regulations for compliance

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

AmerenUE officers have identified an annual review process as a means to update the AmerenUE Environmental Compliance Plan. That annual review will consider the impact that changes in the critical uncertain factors may have on the timing and selection of environmental control technology and the current Environmental Compliance Plan.

4 CSR 240-22.070 (11)

Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall furnish at least the following information:

(A) A decision-tree diagram for each of the alternative resource plans along with narrative discussions of the following aspects of the decision analysis:

1. A discussion of the sequence and timing of the decisions represented by each alternative resource plan, and how the set of resource plans was developed to be responsive to the range of uncertainties in the probability tree; and

AmerenUE developed a set f resource plans from the breadth of generating technology, demand-side management (DSM), and renewable portfolio options analyzed in the deterministic phase. From this set of 104 alternative resource plans, the top 18 alternative resource plans were eventually selected because they were judged to most likely produce the preferred plan under uncertainty. This uncertainty is characterized both by the CO_2 policy, natural gas price, and load growth nodes in the scenario tree, and also by the independent uncertain factors[1] deemed critical to resource plan performance. See the responses to sections 4 CSR 240-22.060 (3) and 4 CSR 240-22.060 (4) for more details.

2. An explanation of how the critical uncertain factors were identified, how the ranges of potential outcomes for each uncertain factor were determined and how the subjective probabilities for each outcome were derived.

With consultation from AmerenUE stakeholders, AmerenUE management and CRA first brainstormed a preliminary list of the variables that could potentially shape build decisions within the planning horizon. This list included such factors as carbon constraints, natural gas supply flexibility, nuclear policy and the business cost of nuclear capacity, and rates of energy efficiency improvement. Then, CRA assessed through preliminary model runs the sensitivity of key IRP variables, such as electricity prices and allowance prices, to variations in each of the uncertainties. As laid out in the response to section 4 CSR 240-22.070 (2), varying nuclear

[1] The critical independent uncertain factors included in the probabilistic analysis were capital costs, interest rates, off-system sales, and the existence of a renewable production tax credit.

policy assumptions like penetration rates, fuel costs, and capacity costs had minimal effect on benchmark IRP parameters. For the other three variables, though, sensitivity analysis and past modeling experience corroborated that the various likely outcomes for each uncertain factor should be reflected in the probability tree of scenarios. The responses to section 4 CSR 240-22.030 (7), 4 CSR 240-22.040 (2) (B) 1- 3, and 4 CSR 240-22.040 (8) (A) clarify how the load growth, CO_2 policy, and natural gas price branches of the probability tree were developed, and how AmerenUE assigned subjective probabilities to each of these scenarios. The figure in 4 CSR 240-22.070 presents the final structure of the probability tree.

(B) Plots of the cumulative probability distribution of each performance measure for each alternative resource plan;

See the responses to sections 4 CSR 240-22.070 (5).

(C) For each performance measure, a table that shows the expected value and the risk of each resource plan;

See the responses to sections 4 CSR 240-22.060 (6)(B) and 4 CSR 240-22.070 (5)(A).

(D) A plot of the expected level of annual unserved hours for the preferred resource plan over the planning horizon;

Section 4 CSR 240-22.070 (7) describes the analysis for emergency import and expected unserved hours. The preferred resource plan did not have any unserved hours over the planning horizon.

(E) A discussion of the analysis of the value of better information required by section (8), a tabulation of the key quantitative results of that analysis and a discussion of how those findings will be incorporated in ongoing research activities.

See the responses to sections 4 CSR 240-22.070 (8) and 4 CSR 240-22.070 (10) (D) – (E).

(F) A discussion of the process used to select the preferred resource plan, including the relative weights given to the various performance measures and the rationale used by

utility decision-makers to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk; and

AmerenUE Management used minimization of the present worth of long-run utility costs as the primary selection criterion in choosing the preferred resource plan. Some other considerations given consideration were the following:

1. Risks associated with critical uncertain factors that will affect the actual costs associated with alternative resource plans.
2. Risks associated with new or more stringent environmental laws or regulations that may be imposed at some point within the planning horizon; and
3. Rate increases associated with alternative resource plans.

The relative weights given to the various performance measures and the rationale used by AmerenUE decision-makers to judge the appropriate tradeoffs between competing planning objectives, expected performance, and risk are detailed in the above Sections of 4CSR 240-22.070.

(F) The fully documented resource acquisition strategy that has been developed and officially adopted pursuant to the requirements of section (10) of this rule.

The resource acquisition strategy is documented in the response to sections 4 CSR 240-22.070 (9) and 4 CSR 240-22.070 (10). AmerenUE President, and Chief Executive Officer, Tom Voss, has approved the preferred resource plan detailed in 4CSR 240-22.070.6. The letter in the summary document "Integrated Resource Plan Report" states his endorsement.