

Com LPS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	115,218	7,796	14.78	0.00
DOWBinary.Monday	29,039	902	32.19	0.00
DOWBinary.Tuesday	29,647	896	33.11	0.00
DOWBinary.Wednesday	29,933	902	33.17	0.00
DOWBinary.Thursday	28,942	900	32.18	0.00
DOWBinary.Friday	27,818	904	30.78	0.00
DOWBinary.Saturday	3,945	896	4.40	0.00
MonthBinary.Jan	-8,347	1,318	-6.33	0.00
MonthBinary.Feb	-10,283	1,294	-7.95	0.00
MonthBinary.Mar	-14,326	1,456	-9.84	0.00
MonthBinary.Apr	-9,452	1,587	-5.96	0.00
MonthBinary.May	-4,635	1,740	-2.66	0.01
MonthBinary.Jun	348	2,026	0.17	0.86
MonthBinary.Jul	139	2,059	0.07	0.95
MonthBinary.Aug	7,506	2,011	3.73	0.00
MonthBinary.Sep	10,328	1,880	5.49	0.00
MonthBinary.Oct	4,765	1,617	2.95	0.00
MonthBinary.Nov	5,309	1,487	3.57	0.00
COMLPSSplines.AvgT	741	151	4.90	0.00
COMLPSSplines.CoolAvgT	-778	163	-4.78	0.00
COMLPSSplines.WarmAvgT	575	185	3.11	0.00
COMLPSSplines.HotAvgT	1,306	212	6.17	0.00
COMLPSSplines.CoolDummy	37,055	8,018	4.62	0.00
COMLPSSplines.WarmDummy	-35,304	10,324	-3.42	0.00
COMLPSSplines.HotDummy	-87,993	14,013	-6.28	0.00
MonthBinary.Yr2008	-16,146	565	-28.60	0.00

Note: Two monthly binary variables were retained in the model despite being statistically insignificant (p-value>.05). The direction and magnitude of the coefficients are reasonable, the standard errors are consistent with the other seasonal variables, and the interpretation of all of the seasonal variables is cleaner with the inclusion of these variables.

Com LPS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	690
Deg. of Freedom for Error	664
R-Squared	0.93
Adjusted R-Squared	0.93
F-Statistic	359
Prob (F-Statistic)	0.00
Mean Abs. % Err. (MAPE)	0.03
Durbin-Watson Statistic	1.28

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Ind SGS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	6,439	4,028	1.60	0.11
DOWBinary.Monday	14,852	499	29.77	0.00
DOWBinary.Tuesday	14,882	497	29.95	0.00
DOWBinary.Wednesday	15,523	497	31.25	0.00
DOWBinary.Thursday	15,274	502	30.44	0.00
DOWBinary.Friday	15,770	504	31.28	0.00
DOWBinary.Saturday	1,982	495	4.00	0.00
MonthBinary.Mar	2,363	637	3.71	0.00
MonthBinary.Apr	2,947	700	4.21	0.00
MonthBinary.May	4,706	823	5.72	0.00
MonthBinary.Jun	5,798	1,003	5.78	0.00
MonthBinary.Jul	4,609	1,012	4.56	0.00
MonthBinary.Aug	5,236	991	5.28	0.00
MonthBinary.Sep	6,729	910	7.39	0.00
MonthBinary.Oct	8,426	719	11.71	0.00
MonthBinary.Nov	6,626	663	10.00	0.00
INDSGSSplines.AvgT	-31	66	-0.47	0.64
INDSGSSplines.CoolAvgT	-165	71	-2.34	0.02
INDSGSSplines.WarmAvgT	386	87	4.44	0.00
INDSGSSplines.CoolDummy	10,153	4,150	2.45	0.01
INDSGSSplines.WarmDummy	-26,241	5,941	-4.42	0.00

Note: The intercept was retained in the model despite being only marginally statistically significant. With the intercept retained, the model results are still reasonable and the other model statistics retain their interpretive value with the presence of an intercept. Additionally, the AvgT variable was retained despite being statistically insignificant. The temperature range represented by this variable exhibits little load-temperature response, so the coefficient is not expected to be very different from zero and the inclusion of the variable does not cause any model predictions that are unreasonable.

Ind SGS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	705
Deg. of Freedom for Error	684
R-Squared	0.80
Adjusted R-Squared	0.79
F-Statistic	133
Prob (F-Statistic)	0.00
Mean Abs. % Err. (MAPE)	0.14
Durbin-Watson Statistic	1.53

Ind LGS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	67,439	2,728	24.72	0.00
DOWBinary.Monday	66,204	2,228	29.71	0.00
DOWBinary.Tuesday	73,178	2,225	32.89	0.00
DOWBinary.Wednesday	76,213	2,237	34.08	0.00
DOWBinary.Thursday	73,079	2,248	32.52	0.00
DOWBinary.Friday	59,164	2,253	26.26	0.00
DOWBinary.Saturday	10,030	2,240	4.48	0.00
MonthBinary.Jan	13,140	3,113	4.22	0.00
MonthBinary.Feb	7,826	3,137	2.50	0.01
MonthBinary.Mar	5,692	3,067	1.86	0.06
MonthBinary.Apr	4,345	3,021	1.44	0.15
MonthBinary.May	6,069	3,178	1.91	0.06
MonthBinary.Jun	19,205	4,126	4.65	0.00
MonthBinary.Jul	28,035	4,231	6.63	0.00
MonthBinary.Aug	19,273	4,060	4.75	0.00
MonthBinary.Sep	17,745	3,688	4.81	0.00
MonthBinary.Oct	2,155	2,992	0.72	0.47
MonthBinary.Nov	7,647	3,111	2.46	0.01
INDLGSSplines.WarmAvgT	580	245	2.37	0.02
INDLGSSplines.WarmDummy	-39,265	17,875	-2.20	0.03
MonthBinary.Yr2008	24,523	1,402	17.50	0.00

Note: Four monthly binary variables were retained in the model despite being only marginally statistically significant ($p\text{-value} > .05$). The direction and magnitude of the coefficients are reasonable, the standard errors are consistent with the other seasonal variables, and the interpretation of all of the seasonal variables is cleaner with the inclusion of these variables.

Ind LGS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	687
Deg. of Freedom for Error	666
R-Squared	0.83
Adjusted R-Squared	0.82
F-Statistic	160
Prob (F-Statistic)	0.00
Mean Abs. % Err. (MAPE)	0.10
Durbin-Watson Statistic	0.91

Ind SPS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-659,129	147,309	-4.47	0.00
DOWBinary.TWT	66,448	640	103.86	0.00
DOWBinary.MonFri	60,576	680	89.02	0.00
DOWBinary.Saturday	12,591	785	16.05	0.00
MonthBinary.Jan	-2,603	1,123	-2.32	0.02
MonthBinary.Feb	-194	1,137	-0.17	0.86
MonthBinary.Mar	-4,822	1,266	-3.81	0.00
MonthBinary.Apr	3,665	1,428	2.57	0.01
MonthBinary.May	6,571	1,543	4.26	0.00
MonthBinary.Jun	13,432	1,759	7.64	0.00
MonthBinary.Jul	10,014	1,788	5.60	0.00
MonthBinary.Aug	10,702	1,737	6.16	0.00
MonthBinary.Sep	12,010	1,637	7.34	0.00
MonthBinary.Oct	5,669	1,395	4.06	0.00
MonthBinary.Nov	3,102	1,307	2.37	0.02
INDSPSSplines.WarmAvgT	258	47	5.46	0.00
INDSPSSplines.HotAvgT	1,143	130	8.81	0.00
INDSPSSplines.WarmDummy	-14,409	2,572	-5.60	0.00
INDSPSSplines.HotDummy	-78,572	10,257	-7.66	0.00
MonthBinary.TrendVar2	-70	2	-39.04	0.00
MonthBinary.TrendVar22	89	4	20.65	0.00

Note: One monthly binary variable was retained in the model despite being statistically insignificant (p-value>.05). The direction and magnitude of the coefficient is reasonable, the standard error is consistent with the other seasonal variables, and the interpretation of all of the seasonal variables is cleaner with the inclusion of this variable.

Ind SPS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	680
Deg. of Freedom for Error	659
R-Squared	0.97
Adjusted R-Squared	0.97
F-Statistic	987
Prob (F-Statistic)	0.00
Mean Abs. % Err. (MAPE)	0.03
Durbin-Watson Statistic	1.74

Ind LPS Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	231,305	1,320	175.21	0.00
DOWBinary.Monday	39,518	1,671	23.65	0.00
DOWBinary.Tuesday	43,116	1,642	26.26	0.00
DOWBinary.Wednesday	44,089	1,646	26.78	0.00
DOWBinary.Thursday	47,793	1,657	28.84	0.00
DOWBinary.Friday	39,701	1,660	23.91	0.00
DOWBinary.Saturday	8,749	1,643	5.33	0.00
MonthBinary.Feb	-5,916	1,754	-3.37	0.00
MonthBinary.Mar	-24,046	1,684	-14.28	0.00
MonthBinary.Apr	10,711	1,759	6.09	0.00
MonthBinary.May	19,754	2,197	8.99	0.00
MonthBinary.Jun	12,943	2,786	4.65	0.00
MonthBinary.Jul	12,256	2,662	4.61	0.00
MonthBinary.Aug	18,868	2,700	6.99	0.00
MonthBinary.Sep	6,493	2,369	2.74	0.01
INDLPSSplines.WarmAvgT	771	127	6.08	0.00
INDLPSSplines.WarmDummy	-42,398	8,609	-4.93	0.00

Ind LPS Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	345
Deg. of Freedom for Error	328
R-Squared	0.91
Adjusted R-Squared	0.90
F-Statistic	203
Prob (F-Statistic)	0.00
Mean Abs. % Err. (MAPE)	0.02
Durbin-Watson Statistic	1.60

Wholesale Weather Normalization Peak Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CONST	-263,874	53,838	-4.90	0.00
DOWBinary.Monday	5,174	387	13.36	0.00
DOWBinary.Tuesday	4,635	382	12.14	0.00
DOWBinary.Wednesday	4,836	383	12.61	0.00
DOWBinary.Thursday	4,616	390	11.83	0.00
DOWBinary.Friday	3,399	392	8.68	0.00
MonthBinary.Mar	-2,538	509	-4.99	0.00
MonthBinary.Apr	-1,809	554	-3.27	0.00
MonthBinary.Sep	-2,705	507	-5.34	0.00
MonthBinary.Oct	-4,247	521	-8.15	0.00
MonthBinary.Nov	-3,049	547	-5.57	0.00
WHSLSplines.CoolAvgT	-223	68	-3.29	0.00
WHSLSplines.WarmAvgT	1,508	95	15.87	0.00
WHSLSplines.HotAvgT	1,961	123	15.94	0.00
WHSLSplines.CoolDummy	10,957	3,692	2.97	0.00
WHSLSplines.WarmDummy	-96,693	6,301	-15.34	0.00
WHSLSplines.HotDummy	-130,287	9,323	-13.98	0.00
MonthBinary.TrendVar	8	1	5.72	0.00
WHSLSplines.AvgT	-113	61	-1.85	0.06
MonthBinary.Yr2008	4,612	535	8.62	0.00
WHSLSplines.ShoulderWarmAvgT	-887	264	-3.36	0.00
WHSLSplines.ShoulderWarmDummy	58,552	17,879	3.28	0.00

The AvgT variable was retained despite being only marginally statistically significant. The temperature range represented by this variable exhibits little load-temperature response, so the coefficient is not expected to be very different from zero and the inclusion of the variable does not cause any model predictions that are unreasonable.

Wholesale Weather Normalization Peak Models Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	709
Deg. of Freedom for Error	687
R-Squared	0.91
Adjusted R-Squared	0.90
F-Statistic	317
Prob (F-Statistic)	0.00
Mean Abs. % Err. (MAPE)	0.05
Durbin-Watson Statistic	1.28

Energy Sales Forecast Models²⁸

Residential Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
ResidentialVars.XHeat	2.14	0.04	52.63	0.00
ResidentialVars.XCool	1.46	0.02	68.15	0.00
ResidentialVars.XOther	0.61	0.01	55.05	0.00

Residential Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	60
Deg. of Freedom for Error	57
R-Squared	0.988
Adjusted R-Squared	0.988
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	1.8%
Durbin-Watson Statistic	1.602

Note: The F-Statistic and associated probability cannot be computed in a regression model, such as the usual SAE specification, that does not include an intercept.

²⁸ 4 CSR 240-22.030(2)(B); EO-2007-0409 – Stipulation and Agreement #11

Commercial SGS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CommercialVars.SGS_XHeat	585.28	30.18	19.40	0.00
CommercialVars.SGS_XCool	919.04	32.23	28.51	0.00
CommercialVars.SGS_XOther	41.90	0.57	73.39	0.00

Commercial SGS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	83
Deg. of Freedom for Error	80
R-Squared	0.921
Adjusted R-Squared	0.919
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	2.8%
Durbin-Watson Statistic	1.589

Note: The F-Statistic and associated probability cannot be computed in a regression model, such as the usual SAE specification, that does not include an intercept.

Commercial LGS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CommercialVars.LGS_XCool	1,392.17	51.07	27.26	0.00
CommercialVars.LGS_XOther	80.99	0.85	95.90	0.00
CommercialVars.LGS_XHeat	288.74	55.67	5.19	0.00

Commercial LGS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	84
Deg. of Freedom for Error	81
R-Squared	0.917
Adjusted R-Squared	0.915
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	2.3%
Durbin-Watson Statistic	1.992

Note: The F-Statistic and associated probability cannot be computed in a regression model, such as the usual SAE specification, that does not include an intercept.

Commercial SPS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CommercialVars.SPS_XCool	286.57	17.53	16.35	0.00
CommercialVars.SPS_XOther	32.80	0.25	130.61	0.00
BinaryVars.Year_2009	(16,929.21)	2,743.82	(6.17)	0.00

Commercial SPS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	60
Deg. of Freedom for Error	57
R-Squared	0.816
Adjusted R-Squared	0.810
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	3.0%
Durbin-Watson Statistic	1.442

Note: The F-Statistic and associated probability cannot be computed in a regression model, such as the usual SAE specification, that does not include an intercept.

Commercial LPS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
CommercialVars.LPS_XCool	162.51	11.71	13.88	0.00
CommercialVars.LPS_XOther	17.69	0.18	100.47	0.00

Commercial LPS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	60
Deg. of Freedom for Error	58
R-Squared	0.799
Adjusted R-Squared	0.795
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	4.3%
Durbin-Watson Statistic	0.977

Note: The F-Statistic and associated probability cannot be computed in a regression model, such as the usual SAE specification, that does not include an intercept.

Industrial SGS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_trans.SGS_Index	4,152.66	195.26	21.27	0.00
Weather_Trans.Bill_CDD_index	11,953.23	1,716.03	6.97	0.00
Weather_Trans.Bill_HDD_Index	19,528.67	2,706.03	7.22	0.00
Binary_vars.Year_2009	(946.48)	289.45	(3.27)	0.00
Binary_vars.October	3,214.23	431.53	7.45	0.00
Binary_vars.November	3,761.78	435.01	8.65	0.00

Industrial SGS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	72
Deg. of Freedom for Error	66
R-Squared	0.748
Adjusted R-Squared	0.729
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	5.4%
Durbin-Watson Statistic	1.116

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

Industrial LGS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_trans.LGS_Index	41,298.59	226.40	182.42	0.00
Weather_Trans.Bill_CDD_index	48,390.29	3,149.78	15.36	0.00
Binary_vars.Year_2009	(6,037.62)	878.79	(6.87)	0.00
Binary_vars.Summer_2006	(2,652.35)	1,766.96	(1.50)	0.14
Binary_vars.January	(6,645.58)	1,263.11	(5.26)	0.00

Industrial LGS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	72
Deg. of Freedom for Error	67
R-Squared	0.903
Adjusted R-Squared	0.897
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	2.3%
Durbin-Watson Statistic	1.832

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

Industrial SPS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_trans.SPS_Index	53,120.46	373.55	142.20	0.00
Weather_Trans.Bill_CDD_index	47,031.27	4,894.24	9.61	0.00
Binary_vars.Year_2009	(8,878.11)	1,435.82	(6.18)	0.00

Industrial SPS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	108
Deg. of Freedom for Error	102
R-Squared	0.632
Adjusted R-Squared	0.614
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	4.9%
Durbin-Watson Statistic	1.904

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

Industrial LPS Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_trans.LPS_Index	123,224	1,184	104.06	0.00
Weather_Trans.Bill_CDD_index	121,278	13,493	8.99	0.00
Binary_vars.March	-16,605	5,680	-2.92	0.00
Binary_vars.Year_2007	-10,014	4,893	-2.05	0.04
Binary_vars.Chrysler_end_shift_LPS	-15,066	9,439	-1.60	0.11
Binary_vars.Year_2009	-17,238	7,337	-2.35	0.02

Industrial LPS Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	108
Deg. of Freedom for Error	102
R-Squared	0.632
Adjusted R-Squared	0.614
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	4.9%
Durbin-Watson Statistic	1.904

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

Residential DTD Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Binary_Vars.January	1,487,802.63	31,919.86	46.61	0.00
Binary_Vars.February	1,185,600.74	30,748.79	38.56	0.00
Binary_Vars.March	892,323.52	30,621.69	29.14	0.00
Binary_Vars.April	599,620.32	30,846.09	19.44	0.00
Binary_Vars.May	285,444.34	30,693.35	9.30	0.00
Binary_Vars.August	154,941.77	30,691.70	5.05	0.00
Binary_Vars.September	431,657.26	30,938.15	13.95	0.00
Binary_Vars.October	722,233.32	30,732.22	23.50	0.00
Binary_Vars.November	1,038,436.43	30,827.74	33.69	0.00
Binary_Vars.December	1,349,351.02	31,405.04	42.97	0.00
Utility_Data.Billing_days	79,706.57	584.45	136.38	0.00

Residential DTD Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	48
Deg. of Freedom for Error	37
R-Squared	0.993
Adjusted R-Squared	0.991
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	1.0%
Durbin-Watson Statistic	1.600

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

Commercial DTD Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Binary_Vars.March	(462,247.47)	88,465.37	(5.23)	0.00
Binary_Vars.April	(1,079,693.45)	88,884.91	(12.15)	0.00
Binary_Vars.May	(1,552,831.50)	88,565.78	(17.53)	0.00
Binary_Vars.June	(1,979,902.50)	89,135.52	(22.21)	0.00
Binary_Vars.July	(2,062,225.27)	89,077.28	(23.15)	0.00
Binary_Vars.August	(1,734,477.65)	88,573.10	(19.58)	0.00
Binary_Vars.September	(1,368,243.27)	88,961.28	(15.38)	0.00
Binary_Vars.October	(813,521.76)	88,662.10	(9.18)	0.00
Utility_Data.Billing_days	200,093.83	1,280.30	156.29	0.00

Commercial DTD Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	72
Deg. of Freedom for Error	63
R-Squared	0.959
Adjusted R-Squared	0.954
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	2.6%
Durbin-Watson Statistic	1.206

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

Industrial DTD Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Binary_Vars.January	4,709.0	1,240.86	3.80	0.00
Binary_Vars.March	(10,304.0)	1,191.15	(8.65)	0.00
Binary_Vars.April	(19,705.6)	1,200.89	(16.41)	0.00
Binary_Vars.May	(30,452.3)	1,193.49	(25.52)	0.00
Binary_Vars.June	(41,926.7)	1,206.69	(34.75)	0.00
Binary_Vars.July	(42,168.4)	1,205.34	(34.99)	0.00
Binary_Vars.August	(35,124.1)	1,193.66	(29.43)	0.00
Binary_Vars.September	(29,086.1)	1,202.66	(24.19)	0.00
Binary_Vars.October	(18,029.2)	1,195.72	(15.08)	0.00
Binary_Vars.November	(6,661.9)	1,198.59	(5.56)	0.00
Utility_Data.Billing_days	3,991.0	22.65	176.20	0.00

Industrial DTD Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	72
Deg. of Freedom for Error	61
R-Squared	0.985
Adjusted R-Squared	0.983
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	1.6%
Durbin-Watson Statistic	1.146

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

SLPA Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Utility_Data.Population	3,332	831	4.01	0.00
Binary_Vars.January	952,290	229,480	4.15	0.00
Binary_Vars.March	-1,398,930	166,313	-8.41	0.00
Binary_Vars.April	-1,970,010	155,640	-12.66	0.00
Binary_Vars.May	-2,850,276	166,650	-17.10	0.00
Binary_Vars.June	-3,873,769	153,861	-25.18	0.00
Binary_Vars.July	-4,501,961	153,842	-29.26	0.00
Binary_Vars.August	-3,849,114	167,273	-23.01	0.00
Binary_Vars.September	-3,269,420	154,991	-21.09	0.00
Binary_Vars.October	-2,121,916	163,812	-12.95	0.00
Binary_Vars.November	-783,443	159,449	-4.91	0.00
Utility_Data.Billing_days	151,997	68,087	2.23	0.03

SLPA Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	75
Deg. of Freedom for Error	63
R-Squared	0.975
Adjusted R-Squared	0.971
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	1.6%
Durbin-Watson Statistic	2.214

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

City of perry Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_trans.perry_index	914,487	62,052	14.74	0.00
WeatherTrans.CAL_CDD_Index	1,954,699	359,948	5.43	0.00
WeatherTrans.CAL_HDD_Index	1,413,258	385,329	3.67	0.00
Binary_Vars.y2009	-251,247	68,186	-3.69	0.00
Binary_Vars.Nov_08	-166,356	144,630	-1.15	0.26
Binary_Vars.Sept_08	-326,827	144,058	-2.27	0.03

City of perry Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	41
Deg. of Freedom for Error	35
R-Squared	0.664
Adjusted R-Squared	0.616
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	9.3%
Durbin-Watson Statistic	0.462

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

City of Kirkwood Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_trans.kirkwood_index	14,213,360	415,533	34.21	0.00
WeatherTrans.CAL_CDD_Index	46,081,793	2,404,245	19.17	0.00
WeatherTrans.CAL_HDD_Index	18,989,484	2,654,199	7.16	0.00

City of Kirkwood Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	53
Deg. of Freedom for Error	50
R-Squared	0.916
Adjusted R-Squared	0.912
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	3.8%
Durbin-Watson Statistic	0.861

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

City of Marceline Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
Econ_trans.Marceline_Index	2,079,978	36,298	57.30	0.00
WeatherTrans.CAL_CDD_Index	4,773,619	211,712	22.55	0.00
WeatherTrans.CAL_HDD_Index	3,844,819	233,444	16.47	0.00

City of Marceline Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	101
Deg. of Freedom for Error	98
R-Squared	0.865
Adjusted R-Squared	0.862
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	4.3%
Durbin-Watson Statistic	1.207

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

City of Kahoka Energy Sales Forecast Model Coefficients

Variable	Coefficient	StdErr	T-Stat	P-Value
WeatherTrans.CAL_CDD_Index	3,201,853	168,438	19.01	0.00
WeatherTrans.CAL_HDD_Index	3,667,268	182,663	20.08	0.00
Econ_trans.kahoka_index	1,398,260	28,119	49.73	0.00

City of Kahoka Energy Sales Forecast Model Statistics

Model Statistic	Value of the Statistic
Adjusted Observations	113
Deg. of Freedom for Error	110
R-Squared	0.846
Adjusted R-Squared	0.843
F-Statistic	#NA
Prob (F-Statistic)	#NA
Mean Abs. % Err. (MAPE)	4.4%
Durbin-Watson Statistic	0.898

Note: The F-Statistic and associated probability cannot be computed in a regression model that does not include an intercept.

Compliance References

4 CSR 240-22.030(1)(B)	68
4 CSR 240-22.030(1)(B)1	76
4 CSR 240-22.030(1)(C)2.C	200, 213
4 CSR 240-22.030(2)(B)	200, 213, 227
4 CSR 240-22.030(8)(A)	1, 7, 17, 22, 27, 32, 36, 40
4 CSR 240-22.030(8)(A)1	1, 7, 17, 22, 27, 32, 36, 40
4 CSR 240-22.030(8)(A)2.A	1, 7, 17, 22, 27
4 CSR 240-22.030(8)(A)2.B	47, 55, 57, 60, 63
4 CSR 240-22.030(8)(B)	76, 83, 91, 96
4 CSR 240-22.030(8)(B)1	68
4 CSR 240-22.030(8)(B)2	83, 91, 96
4 CSR 240-22.030(8)(D)	44, 192, 196
4 CSR 240-22.030(8)(D)1	44, 192
4 CSR 240-22.030(8)(D)2	196
4 CSR 240-22.030(8)(D)3	44, 192, 196
4 CSR 240-22.030(8)(E)	120
4 CSR 240-22.030(8)(E)1	112, 120
4 CSR 240-22.030(8)(E)2	112, 120
4 CSR 240-22.030(8)(F)	120
4 CSR 240-22.030(8)(F)1	120
4 CSR 240-22.030(8)(F)2	120
4 CSR 240-22.030(8)(G)	1
EO-2007-0409 – Stipulation and Agreement #11	27, 213, 227
EO-2007-0409 – Stipulation and Agreement #8	4, 17, 22, 27

Abbreviations

Res:	Residential
Com :	Commercial
Ind:	Industrial
WS:	Wholesale
DTD:	Dusk to Dawn
SLPA:	Street Light and Public Authority
SGS:	Small General Service
LGS:	Large General Service
SPS:	Small Primary Service
LPS:	Large Primary Service
WN:	Weather Normalized
LTS:	Large Transmission Service
I. Lighting:	Indoor Lighting
O. Lighting:	Outdoor Lighting
Refrig:	Refrigerator
Whsl:	Wholesale
CI Wash:	Clothes Washing Machine
Elec DHW:	Electric Water Heating

4. Thermal Resources

Highlights

- *Ameren Missouri currently owns and operates 9,606 MW of thermal resources: 5,449 MW of coal, 1,190 MW of nuclear, and 2,967 MW of peaking natural gas.*
- *Ameren Missouri, with assistance from Black and Veatch, evaluated 47 coal and gas resource options, five of which were ultimately used in further analysis.*
- *The 1600 MW US EPR from Areva represents the nuclear resource option and was analyzed at 30% and 50% Ameren Missouri ownership levels.*
- *Burns & McDonnell completed a Condition Assessment of the Meramec plant to determine ongoing costs to keep the plant operating safely and reliably through the planning horizon. This analysis facilitates decision making with respect to retirement of the plant.*

Ameren Missouri worked with Black and Veatch to evaluate 47 different coal and gas options. Of those 47, five were evaluated further as part of alternative resource plans, as discussed in Chapter 9. The five coal and gas resources considered to be most promising were: coal with carbon capture, Greenfield combined cycle, Venice conversion to combined cycle, combined cycle retrofit at Meramec, and Greenfield simple cycle.

Ameren Missouri continued to evaluate the 1600 MW US EPR to represent the nuclear resource option and has been following the development of modular reactors. To address financing constraints and provide comparable unit sizes to other supply-side resources, both 30% and 50% ownership levels were considered in the development of alternative resource plans.

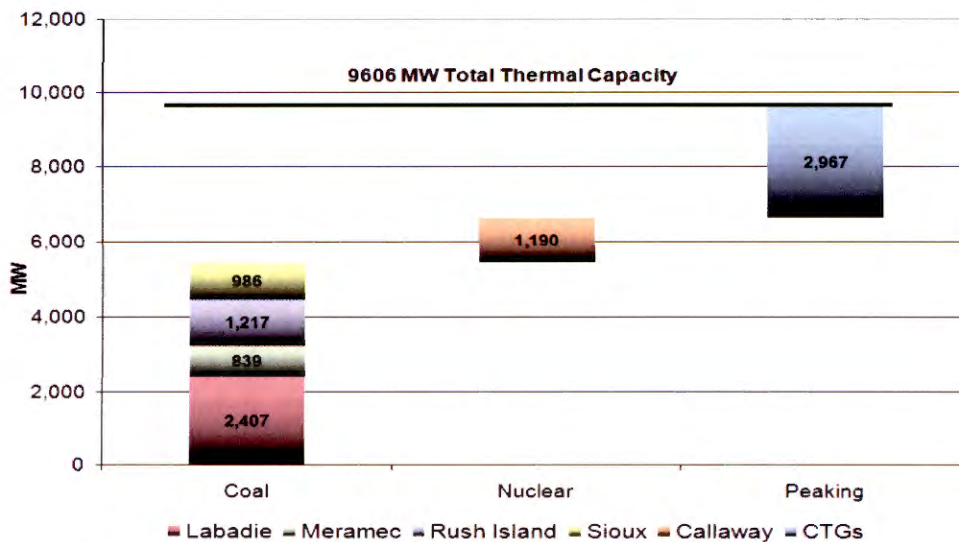
Burns & McDonnell completed a Condition Assessment of the Meramec plant to determine ongoing costs to keep the plant operating safely and reliably through the planning horizon which were included as cost savings in retirement cases. Two Meramec retirement dates, 2015 and 2022, were initially evaluated in the development of alternative resource plans. After the development of two more stringent environmental regulation scenarios, as described in Chapter 8, a retirement date of 2016 was modeled for the final 14 candidate resource plans.

Ameren Missouri has evaluated a range of generation efficiency options as part of a 2009 End-to-End Efficiency Study performed with the assistance of EPRI, which helped identify the most promising projects. Since the analysis was based on generic data, Ameren Missouri will take a closer look at the top projects to determine which ones merit development.

4.1 Existing Thermal Resources

Ameren Missouri owns and operates thermal and hydroelectric power plants to serve the energy needs of its customers. About 96% of generation comes from its coal-fired, nuclear and oil/natural gas-fired power plants. Ameren Missouri continuously evaluates power plant performance and upgrades that are necessary to operate its plants in an efficient, safe and environmentally-friendly way. Figure 4.1 reflects the 2010 summer net capability of Ameren Missouri's existing thermal plants.

Figure 4.1 Existing Thermal Resource Capacity



4.1.1 Existing Coal Resources

Ameren Missouri has four coal-fired plants in its generation fleet. The Labadie, Rush Island, Meramec and Sioux plants have a total summer plant capability of 5,449 MW.

Labadie Plant

Labadie plant is located outside Labadie, MO, on 1,100 acres adjacent to the Missouri River, 35 miles west of downtown St. Louis. The plant consists of four generating units with a summer net capability of 2,407 MW's. The first unit started operating in 1970 and the plant was fully operational in 1973.

Labadie Plant is a national leader in generating electricity cleanly and efficiently:



- The state of Missouri presented Labadie Plant with the Resource Steward Award in 1983 to honor the company's efforts toward "preserving and wisely using Missouri's precious resource" by removing PCBs from our environment. Between

1981 and 1997, Labadie converted more than 4.5 million gallons of PCB-contaminated oil into an estimated 56,000 MWh's of electricity.

- In 1998, Labadie was one of three Ameren Missouri plants to earn the Missouri Governor's Pollution Prevention Award for successfully reducing nitrogen oxide (NO_x) emissions- 50% more than required by Missouri regulations.
- In 2000, Labadie was recognized by the Environmental Protection Agency as the nation's lowest emitter of NO_x.

From 2000 to 2009, Labadie set generation records six out of ten years. Labadie unit 2 Low Pressure (LP) turbine retrofits were among the existing plant upgrades included in the 2008 IRP. The project is scheduled to be completed in 2013, bringing the plant's net summer capability up by 11 MW to 2,418 MW¹.

Rush Island Plant

Rush Island power plant is located 40 miles south of downtown St. Louis, in Jefferson County, Mo., on 500 acres on the western bank of the Mississippi River. The plant has two units with a net summer capability of 1,204 MW (prior to the upgrades discussed below). The first unit started operation in 1976 and the second unit in 1977.



Rush Island LP turbine retrofits were analyzed and passed on in the 2008 IRP. The Rush Island Unit 2 LP turbine retrofit was completed in April 2010, resulting in a 13 MW capacity increase. Unit 1 LP turbine retrofit is scheduled to be completed in 2013, again with a capacity increase of 13 MW². With both upgrades completed, the plant's net summer capability will be 1,230 MW by 2013.

Meramec Plant

Meramec coal-fired plant is located in South St. Louis County on the Mississippi River on 420 acres. The plant began operation in 1953. Net summer capability of the plant, which consists of four units, is 839 MW's. It is the oldest coal plant Ameren Missouri owns. A detailed condition assessment study was performed for Meramec and is discussed in section 4.7.



¹ 4 CSR 240-22.040(4)

² 4 CSR 240-22.040(4)

Warmer river temperatures in the summer months cause an increase in the backpressure on Unit 3 & Unit 4 and, consequently, limit the output of the turbines on both units. To alleviate this problem, a circulating water pump upgrade has been scheduled to be completed before summer of 2011 with \$100,000 of capital expenditures in 2010 and \$100,000 of O&M in 2011. The modification includes rewinding the current motors to a higher rotational speed on the 3A and 3B circulating water pumps. The increased speed on these circulating water pumps will increase the pumping capacity of both pumps, which will cause more water to be pumped in to the condensers of both Unit 3 and Unit 4 as the 3A, 3B, 4A, & 4B circulating water pumps all feed a common water header that supplies water to both Unit 3 & Unit 4 condensers. The increased water flow through the condensers will allow for improved cooling of the turbine exhaust steam of the Unit 3 & Unit 4 LP turbines, which will result in an improved lower backpressure of the LP turbines on both Unit 3 and Unit 4. The upgrade will increase summer net capacity of Unit 3 and Unit 4 by 5 MW and 10 MW, respectively³. The upgrades will bring the total summer net capacity of the plant to 854 MW.

Sioux Plant

Sioux power plant is located in St. Charles County, Mo., 28 miles northeast of downtown St. Louis. It has two units which started operations in 1967 and 1968, respectively, and has a total net summer capability of 986 MW.

Sioux Power Plant accomplished many industry firsts:



- Pioneered slag-removal techniques now used nationwide.
- One of the first to install cyclone furnaces that can burn multiple fuels.
- One of the first to receive coal on the unit train concept.
- Became the first generating plant in Missouri to burn chipped rubber tires to augment coal as an alternate fuel source. Since the program began in 1992, Sioux Plant has burned more than 19 million discarded tires, which would otherwise end up in a landfill, without adversely affecting power plant emissions.

Ameren Missouri has installed scrubbers at its Sioux plant to comply with the federal Clean Air Interstate Rule (CAIR). CAIR requires a major reduction in sulfur dioxide (SO₂) and NO_x emissions on a regional scale by 2015 to help areas in the eastern U.S. achieve healthier air quality. The Sioux scrubbers are capable of removing up to 99%

³ 4 CSR 240-22.040(4)

of the SO₂ from the boiler flue gas and started operating in October and November, 2010.

4.1.2 Existing Peaking Resources

Ameren Missouri owns and operates oil or natural gas-fired combustion turbine generators (CTG) to provide electricity during times of high demand or when its base load plants are not operating due to a forced outage or scheduled maintenance.

Table 4.1 lists the Ameren Missouri combustion turbines and their 2010 summer net generating capabilities. A MISO deliverability study determined that the Audrain combustion turbines have a transmission constraint which reduces the plant's available output by approximately 30 MW, which is not reflected in Table 4.1. A MISO System Impact Study estimated that transmission system upgrades to regain the 30 MW of Audrain capacity would cost up to \$5 million.

Table 4.1 CTG Capability

Plant	Fuel	Net MW
Audrain	Gas	608
Goose Creek	Gas	438
Kirksville	Gas	13
Pinckneyville	Gas	316
Raccoon	Gas	304
Viaduct	Gas	26
Kinmundy	Gas/Oil	208
Meramec CTG	Gas/Oil	112
Peno Creek	Gas/Oil	188
Venice	Gas/Oil	491
Fairgrounds	Oil	55
Howard Bend	Oil	43
Mexico	Oil	55
Moberly	Oil	55
Moreau	Oil	55
Total		2,967

Currently, low power and capacity prices do not warrant an immediate need for Ameren Missouri to remove the transmission constraint. For the purposes of this IRP, the transmission upgrade is expected to occur before the 2020 summer peak.⁴

4.1.3 Existing Nuclear Resource

Callaway plant is located about 100 miles west of St. Louis, Missouri, in Callaway County. The plant started operations in December 1984 and is the only power plant that uses nuclear fuel in Ameren Missouri's generation fleet. It is the second largest power generator on the Ameren Missouri system with a net capability of 1,190 MW, after Labadie coal plant. More than 1,000 Ameren Missouri employees and contractors work at the plant.



⁴ EO-2007-0409 – Stipulation and Agreement #15

Ameren Missouri evaluated a 70 MW uprate project during its IRP process⁵. This project was included in the 2008 IRP but was deferred due to budget constraints. The analysis of the project, which is estimated to be \$134.6 Million, showed a levelized cost of energy (LCOE) of about 5 cents/kWh. The up-rate is assumed to be completed by 2017, bringing the net plant capability to 1,260 MW.

4.2 New Thermal Resources

4.2.1 Coal and Gas Options

Ameren Missouri engaged Black & Veatch to conduct a supply-side screening analysis of various power generation technologies in support of Ameren Missouri's IRP.

A multistage approach was used to determine the list of options to be characterized in the analysis. The first stage consisted of the development of a "universe" list of potential gas and coal-fueled generation options and a fatal flaw screening. The universe list was screened to develop an "evaluated" list of options by conducting a high-level fatal flaw analysis, based on Black & Veatch's engineering experience. The universe list and fatal flaw analysis are included in Chapter 4 – Appendix A. Options that did not pass the high-level fatal flaw analysis consisted of those that could not be reasonably developed or implemented by Ameren Missouri.

After the fatal flaw screening, the second stage consisted of a Preliminary Screening. The purpose of the Preliminary Screening was to provide an initial ranking of the evaluated resource options. To support the screening, performance, cost, and operating estimates were developed for each evaluated option, utilizing input from Ameren Missouri and Black & Veatch's internal resources⁶. A scoring methodology was developed with the intent of comparing options within their fuel group. A weighted score was then developed for each option by analyzing the following categories: utility cost, environmental cost, risk reduction, planning flexibility, and operability. Several criteria were established within each category, on the basis of Black & Veatch's experience and considering Ameren Missouri's planning needs. Numerical scores were assigned according to how each option met the criterion. The criteria scores were weighted and summed to obtain a category score. The sum of the category scores resulted in the overall preliminary screening score. The preliminary screening analysis can be found in Chapter 4 – Appendix B. It is important to note that the USCPC and IGCC options with carbon capture did not include any sequestration costs during the screening analysis. Ameren Missouri estimated the sequestration costs per MWh generated using estimates from a Standard and Poor's report⁷. The report estimated CO₂ transportation

⁵ 4 CSR 240-22.040(4)

⁶ 4 CSR 240-22.040(8)(B)1; 4 CSR 240-22.040(8)(C)1

⁷ <http://www2.standardandpoors.com/spf/pdf/events/PwrGeneration.pdf>, page 2

cost at \$6/ton and storage at \$4/ton in 2007 dollars, which equates to a total of \$10.61/ton in 2009 dollars using a 3% escalation rate. The sequestration cost per ton (\$10.61) was then converted to cost per MWh (\$12.45) and was added to the variable cost per MWh in the Midas modeling stage.

From the Preliminary Screening scoring, a limited number of evaluated options were selected as part of the third stage of the analysis. Using the Preliminary Screening scoring results as a guide, Ameren Missouri and Black & Veatch selected 10 candidate options to consider for Ameren Missouri's resource modeling effort. These options are shown in Table 4.2 and are listed by technology type and fuel source.

Table 4.2 Preliminary Candidate Options⁸

Fuel Type	Base Load Technologies
Coal	Greenfield - USCPC
Coal	Greenfield - USCPC w/Carbon Capture
Coal	Greenfield - IGCC
Coal	Greenfield - IGCC w/Carbon Capture
	Intermediate Load Technologies
Gas	Venice - 2-on-1 501F Combined Cycle Conversion
Gas	Greenfield - 2-on-1 501F Combined Cycle
Gas	Meramec - Unit 4 STG in a Combined Cycle Conversion
	Peaking Load Technologies
Gas	Greenfield - Two Siemens 501Fs with SCR
Gas	Mexico - One GE LM6000 SPRINT with SCR
Gas	Raccoon Creek - One GE 7EA with SCR

Once Ameren Missouri completed the screening analysis and started developing Alternative Resource Plans it was evident the number of resource options needed to be reduced because of modeling limitations. As discussed in Chapter 2, Ameren Missouri has assumed that future coal builds will require carbon capture, thus we can eliminate coal resources without carbon capture from further consideration. In addition, it is reasonable to use one coal option to represent coal in the analysis since operating costs and performance for USCPC and IGCC are similar. If the coal option performs well then it may be necessary to do more analysis to determine the best coal technology. Based on the screening analysis, it was concluded that USCPC will be analyzed to represent the coal resource type. Although there are three combined cycle options, each represents a unique configuration – i.e., Greenfield, conversion, or retrofit. Further analysis of the combined cycle options is necessary to help identify which option is best. There is no need to analyze three separate simple cycle options as these

⁸ 4 CSR 240-22.040(9)(B)

resources are quite flexible; therefore, the Greenfield option was selected to represent the simple cycle resource option.⁹ The final candidate resource options are listed in Table 4.3.

Table 4.3 Final Candidate Options

Technology Description	Load Type	Fuel Type
Greenfield - USCPC w/Carbon Capture	Base	Coal
Venice - 2-on-1 501F Combined Cycle Conversion	Intermediate	Natural gas
Greenfield - 2-on-1 501F Combined Cycle	Intermediate	Natural gas
Meramec - Unit 4 STG in a Combined Cycle Conversion	Intermediate	Natural gas
Greenfield - Two Siemens 501Fs with SCR	Peaking	Natural gas

Alternative resource plans that include Venice combined cycle conversion were modeled by also adding a simple cycle option to replace the capacity converted at Venice so that the total capacity addition in the plan is comparable to the alternative resource plans that include other resource options.

4.2.2 New Nuclear Resource

Ameren Missouri screened twelve different nuclear technologies in its 2008 IRP with consultation from Black & Veatch. After the initial screening, U.S. EPR, ABWR and AP1000 were evaluated in more detail, and U.S. EPR was selected as the choice of nuclear technology and characterized in more detail. For this IRP, Ameren Missouri decided to rely on the results of that study and chose the U.S. EPR to represent the new nuclear resource option.

Although the new nuclear plants in the current global nuclear expansion are large scale reactors employing advanced safety features and enhanced reliability, the United States nuclear industry is considering a different approach by turning away from “bigger is better” toward “smaller is better” reactors. These are often referred to as small modular reactors (SMRs).

Small Modular Reactors

SMR's have a number of characteristics that illustrate the unique role that they can play in our energy mix: (1) SMR's are relatively small in power output, from 25 MW to 350 MW, versus large-scale reactors that can have a power output of more than 1,200 MW; and (2) several SMR designs are modular. These two characteristics demonstrate the differences between SMR's and traditional large-scale reactors. Unlike traditional reactors, SMR's would be manufactured and assembled at the factory and shipped to the site as nearly complete units, resulting in much lower capital costs and much shorter construction schedules. SMRs also permit greater flexibility through smaller,

⁹ 4 CSR 240-22.040(2)(C); 4 CSR 240-22.040(8)(B)2; 4 CSR 240-22.040(8)(C)2;
4 CSR 240-22.040(9)(A)3

incremental additions to baseload electrical generation, and more SMRs can be added and linked together for additional output as needed.

SMR designs and concepts can be grouped into three sets based on design type, licensing and deployment schedule, and maturity of design.

- Light water reactor (LWR) based designs » 10-15 years to commercial availability
- Non-LWR designs » 15-25 years to commercial availability
- Advanced Reactor Technologies » 20-30 years to commercial availability

Of the many contenders in this arena, only two have currently announced their intent to submit an application for design certification with the NRC - the Babcock & Wilcox mPower reactor and the NuScale reactor. Both use Generation III+ light water PWR design and are expected to be submitted for design certification in 2012.

U.S. EPR

The U.S. EPR is a four-loop Pressurized Water Reactor (PWR) with rated thermal power of 4590 MWt, designed by Areva NP. While Areva NP has never built a PWR in the United States, it has extensive experience throughout the world.

While the firm's initial expertise was developed while both Siemens and Areva were licensees to Westinghouse Electric Corporation

(Westinghouse) in the 1970's and 1980's, their more recent N4, four-loop design was entirely developed in-house.

Table 4.4 EPR Projects Worldwide

Project	Country	Expected In-Service Date
Olkiluoto 3	Finland	2013
Flamanville 3	France	2014
Taishan 1	China	2013
Taishan 2	China	2015

The U.S. EPR is an evolutionary design with active safety features. The Reactor Coolant System (RCS), loop configuration and main component are similar to currently operating PWRs. The U.S. EPR RCS includes a reactor vessel housing the fuel assemblies, a pressurizer, one Reactor Coolant Pump (RCP) per loop, one Steam Generator (SG) per loop, associated piping and related control and protection systems. This fundamental design is identical to operating PWRs. The RCS is housed within a concrete containment building which is internally lined with steel. The containment building is then enclosed in a Shield Building, with an annular space between the two buildings. The Shield Building is an additional safeguard not found in currently licensed US PWRs.

The plant is designed with four trains of safety systems. These systems are physically separated into four Safeguards Buildings. The Reactor Building, Fuel Building and two of the four Safeguards Buildings are entirely protected against aircraft hazards and external explosions. These levels of redundancy and separation of safety systems are

advanced beyond that found in any currently operating US PWR. Each safety train has a dedicated Emergency Diesel Generator (EDG) in the event of loss of off-site power. Two additional diesel generators provide further protection against a simultaneous loss of off-site power and all four EDGs.

The U.S. EPR design philosophy is based upon improving the design of currently operating PWRs in the areas of increased redundancy and separation, reducing core damage frequency, reducing large radioactivity release frequency, mitigating the effects of severe accidents, protecting critical systems from external events, improved man-machine interface and allowing more time for operator actions.

Key U.S. EPR design parameters include the following:

- Design life- 60 years
- Thermal power- 4,590 MW
- Net average electrical power- 1,600 MW
- Efficiency- 36 percent
- Number of fuel assemblies- 241
- Fuel lattice- 17 x 17
- Active Fuel Length- 13.78 ft
- Rods per Assembly- 265
- Refueling Frequency- Up to 24 months

The reactor can use Uranium dioxide enriched in the fissile isotope up to 5% or Uranium and Plutonium mixed oxide¹⁰.

U.S. EPR design certification is currently under U.S. Nuclear Regulatory Commission review with a target date of December 2011 for the final Safety Evaluation Report (SER) to be issued. The overall construction schedule is dependent on site conditions, organization and policies, and local working conditions but the expected contract effective date to commercial operations duration is 70 months, including 6 months of start-up testing¹¹. The technology's ability to be licensed and built in a reliable and timely manner is the only constraint of significance¹².

Ameren Missouri analyzed 30% and 50% ownership options on a 1,600 MW unit in this IRP since building a 1,600 MW unit with sole ownership presents a much higher financing risk than Ameren Missouri would be willing to take on given the current economic and financial environment. Also, the size of the new capacity addition with 30% and 50% ownership provides for a more equitable comparison to the other similarly sized resource options modeled in the alternative resource plans, thus avoiding any

¹⁰ 4 CSR 240-22.040(1)(A)

¹¹ 4 CSR 240-22.040(1)(D)

¹² 4 CSR 240-22.040(1)(J)

advantages/disadvantages due to differences in the size of capacity additions. Moreover, smaller capacity sizes for the nuclear resource option serve as better proxies for possible modular reactors in the future.

Capital Cost

Ameren Missouri conducted a literature search of overnight capital costs including owners' costs. Table 4.5 lists the more recent capital cost per kW estimates from different sources, which include owner's cost but exclude AFUDC.

Table 4.5 Nuclear Overnight Capital Cost¹³

\$2009 \$/kW	Connecticut	KCPL	EPRI	B&V	EIA	Lazard	Average
	4,159	3,792	4,222	3,503	3,520	7,571	4,460

Sources:

- Connecticut- Integrated Resource Plan for Connecticut, January 1, 2008, p.C-4
- KCPL- KCP&L Integrated Resource Plan 2009 Filing, Appendix 4A, p. CRS-97
- EPRI- Program on Technology Innovation: Integrated Generation Technology Options, Dec, 2008, p. 1-12
- B&V- Black & Veatch Market Analysis (2007), National Renewable Energy Laboratory, "Technology Cost and Performance Study", www.nrel.gov/analysis/docs/re_costs_20090806.xls
- EIA- Assumptions to the Annual Energy Outlook 2009, p. 89
- Lazard- Levelized Cost of Energy Analysis- Version 3.0, June 2009, p. 9

Ameren Missouri chose to use EPRI's capital cost for the nuclear option, which was closest to the average of all cost estimates; therefore bringing the total capital cost of a new 1,600 MW nuclear option to \$6.755 Billion.

Scheduled Outage

The refueling cycle requirements control the scheduled routine and maintenance outages for nuclear units. Current enrichment limits of 5 percent prevent fuel cycle lengths longer than 24 months. Ameren Missouri assumed an 18 month refueling schedule; scheduled maintenance would occur in a 24 day period (3.43 weeks) every 18 months. However, for modeling purposes, this was translated into an annual maintenance schedule that equates to 2.29 weeks every year.

Forced Outage Rate and Availability

Based on an expected forced outage rate of 2.0% and scheduled maintenance 24 days every 18 months, annual availability is estimated to be at 94%.¹⁴ Characterization of the

¹³ 4 CSR 240-22.040(1)(E)

¹⁴ 4 CSR 240-22.040(1)(H); 4 CSR 240-22.040(1)(I)

technology included three possible forced outage rates and the probabilities around those- the expected FOR 2% with 70% probability, FOR of 3% with 20% probability and FOR of 4% with 10% probability. The probability weighted average FOR, which is 2.4%, was used in Midas modeling.

Waste Generation

In the previous IRP, intermediate and low-level waste volume for U.S. EPR was estimated to be 2,080 m³.¹⁵

Water Impacts

In the 2008 IRP, water impacts were evaluated through thermal efficiency, which was estimated to be 36% for the U.S. EPR. Consumptive use of water is primarily attributable to evaporation losses from the natural draft cooling towers. The U.S. EPR will utilize two natural-draft cooling towers with evaporative losses of approximately 22,000 gpm. Blowdown from the new cooling towers will be approximately 5,500 gpm each, or a total of 11,000 gpm. The unit will consume a total of approximately 27,600 gpm including estimated cooling tower drift. In comparison to average annual flow of the Missouri River over 60 years, such losses are estimated to require less than 0.1 percent of river flow. The water resources so committed for plant operation will have no effect on other users downstream from the plant¹⁶.

4.3 Transmission Interconnection¹⁷

A detailed transmission study at this stage of the planning process was not in Black & Veatch's scope of work, so Black & Veatch made a generic assumption that transmission costs make up 50% of owner's costs. Ameren Missouri sought to include somewhat more specific interconnection costs, and its Transmission Planning Department developed interconnection cost estimates for the candidate resource options based on limited site information and general configuration assumptions¹⁸. The assumptions and associated cost estimates are summarized in Table 4.6.

¹⁵ 4 CSR 240-22.040(1)(K)2

¹⁶ 4 CSR 240-22.040(1)(K)3

¹⁷ 4 CSR 240-22.040(3); 4 CSR 240-22.040(6)

¹⁸ EO-2007-0409 – Stipulation and Agreement #15, the Callaway 2 interconnection study has been withdrawn from the MISO study queue

Table 4.6 Candidate Option Transmission Cost Estimates

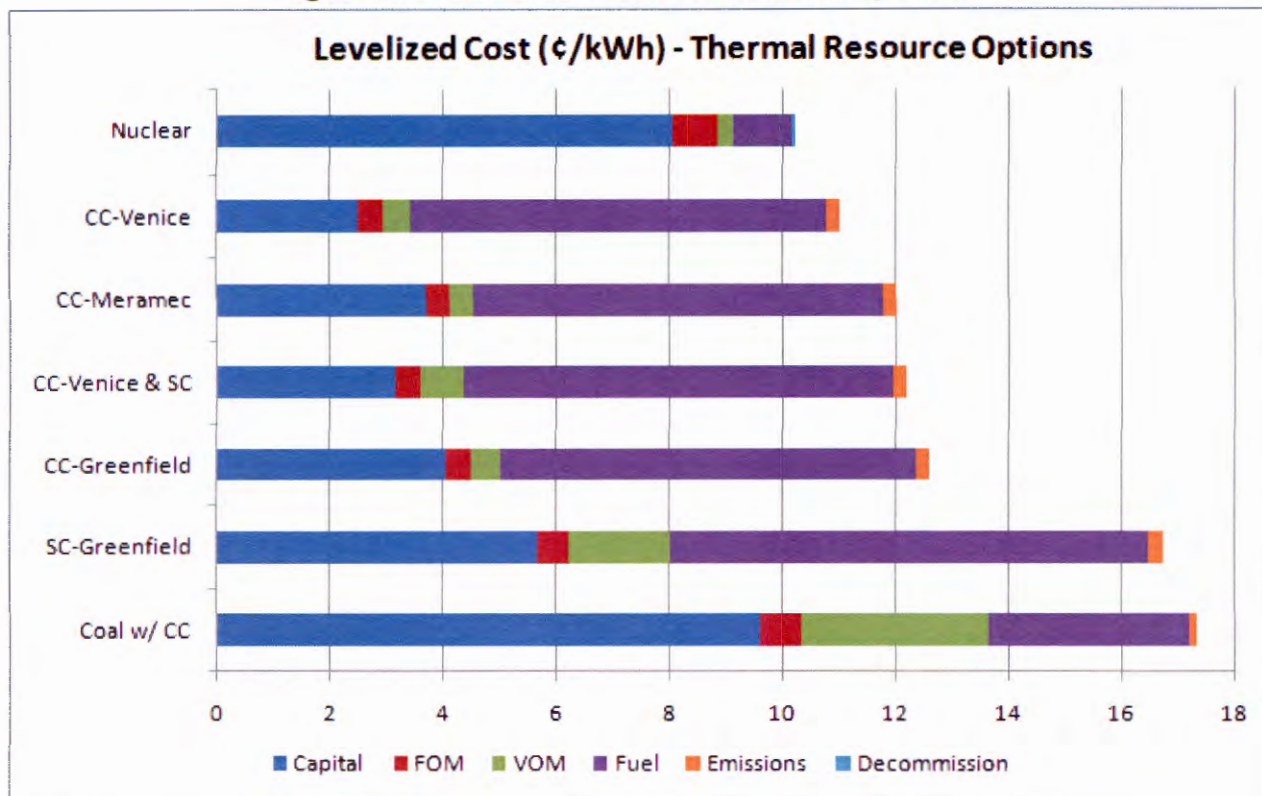
Highly Confidential

Using the interconnection costs in Table 4.6, owner's cost and the total project cost excluding AFUDC were adjusted for all resource options other than nuclear. Since 50% of owner's cost was assumed to be transmission cost in Black and Veatch numbers, half of owner's cost was subtracted and replaced with the revised transmission costs, resulting in the following owner's costs and total project cost excluding AFUDC as listed in Table 4.7.

Table 4.7 Revised Owner's and Total Project Costs

Highly Confidential

Levelized cost of energy after adjustments were calculated for the final thermal resource options using the probability-weighted average of inputs from the ten scenarios developed and discussed in Chapter 2. The results are shown in Figure 4.2. The LCOE for Venice combined cycle conversion is estimated by itself and also with the addition of a simple cycle option as it was modeled in the alternative resource plans to have a total capacity addition that is comparable to the other resource options.

Figure 4.2 LCOE for Final Candidate Options¹⁹

4.4 Meramec Retirement

Ameren Missouri retained the services of Burns & McDonnell to complete a Condition Assessment of the Generation Assets at the Meramec Plant and provide relevant information to adequately support a retirement analysis as part of the IRP. The study provided recommendations for future capital projects and ongoing O&M activities in order to maintain a safe and reliably operating plant under three separate scenarios: 1) Continue operation of all units through 2021, 2) Continue operation of all units through 2025 and 3) Continue operation of all units through 2041.

Additional Retirement Dates

In its IRP modeling, Ameren Missouri included 2022 and 2042 retirement cases as well as a 2015 retirement case in the integration analysis. In the risk analysis, due to uncertainties around environmental regulations, a new retirement date of 2016 (the Plant continues operations through 2015) was introduced. Since the 2015 and 2016 retirements were not covered in the Burns & McDonnell study, Corporate Planning estimated related capital expenditures and O&M costs using the data provided in the study.

¹⁹ 4 CSR 240-22.040(2)(C)

The capital expenditure and O&M data for the last few years of the 2022 retirement were de-escalated to coincide with the last few years of the 2015 and 2016 retirement cases. The 2042 retirement case is beyond the planning horizon; therefore, it was considered to be the 'no retirement' base assumption and was assumed to be implicitly included in the long-range capital and O&M costs. The differences between the CAPEX and O&M costs from the 'no retirement' case were entered into the Midas model as cost savings associated with retirement cases.

Capital Expenditures

Burns & McDonnell obtained a record of previous capital projects and the then current 2009 capital and O&M forecast, and all of the planned capital work in the subsequent five years was added to the Master List. Only projects valued above \$100,000 were included for comparison against the plant's current assets. The O&M forecast was captured to assess the annual spend for all maintenance activities.

The Master List was expanded to show not only the current forecast projections through 2013, but potential capital projects from 2014 through 2021, 2025 and 2041. Cost estimates were placed in the years selected for each project identified. The timing of each project was based on the expected life of each component and the selection of a projected unit outage.

The budget plan recommended in this study is expected to be in line with past costs and have a justification based on historical requirements and the condition assessment of the plant's components. Both capital expenditures and O&M expenses in 2009 dollars were escalated at 3% to determine nominal costs.

Table 4.8 shows a summary of the major replacements (greater than \$5MM each) that have been identified beyond the 2009 Capital Forecast:

Table 4.8 Recommended Major Projects

Major Projects	2015	2016	2022	2042
Unit 2 HP Turbine Rotor Replacement	✗	✗	✓	✓
Unit 1&2 GSU Transformer Replacements	✗	✗	✓	✓
Unit 1&2 DCS Upgrade	✗	✗	✓	✓
Unit 3 DCS Upgrade	✗	✗	✓	✓
Unit 4 FD Fan and ID Fan Rotor Replacements	✗	✗	✓	✓
Unit 4 GSU Transformer 4A Replacement	✗	✗	✓	✓
Unit 1&2 ID Fan Rotor Replacement	✗	✗	✗	✓
Unit 3 Convective Superheater Replacement	✗	✗	✗	✓
Unit 4 Reheater Middle and Lower Bank Replacement	✗	✗	✗	✓
Unit 1&2 Primary Superheater Replacement	✗	✗	✗	✓
Unit 1&2 #1 and 2 Feedwater Heater Replacements	✗	✗	✗	✓
Unit 1&2 Cold End Air Heater Replacements	✗	✗	✗	✓

Major Projects	2015	2016	2022	2042
Unit 1&2 DCS Upgrade	✗	✗	✗	✓
Unit 3 Economizer Replacements	✗	✗	✗	✓
Unit 3 DCS Upgrade	✗	✗	✗	✓
Unit 4 Primary Superheater Horizontal Section Replacement	✗	✗	✗	✓
Unit 4 DCS Replacement	✗	✗	✗	✓

These recommendations were made based on life expectancies of major components on each unit and the goal of continued operation in a safe and reliable manner.

It is important to not only determine the capital expenditures for the scenarios studied, but also the timing of the work. It would not be prudent to spend large amounts on replacements close to the expected retirement of the plant. The budget recommendation for the 2022 retirement date assumes that outages will continue through 2018. This would be close to the last major outage for each unit before retirement. Likewise, outages are recommended through 2023 for the 2026 retirement date, and 2038 for the 2042 retirement date.

The differences in the capital expenditures from the 2042 retirement case were estimated for 2015, 2016 and 2022 retirement dates and were used in the Midas model for the different Meramec retirement scenarios. The capital expenditure savings for these three retirement dates are presented in Table 4.10.

Operations & Maintenance

O&M expenditures were divided into labor and non-labor categories. The labor portion is annually consistent, with increases for overhead adjustments and wage increases, whereas the non-labor portion is heavily outage dependent. Labor and non-labor O&M expenses from the 2009 forecast are summarized in Table 4.9.

Table 4.9 Forecasted Labor and Non-Labor O&M Expenses 2009-2014 (2009 \$'s)

Million \$'s	2009	2010	2011	2012	2013	2014
Labor O&M	\$22.99	\$ 22.98	\$23.59	\$24.23	\$ 25.25	\$25.84
	<i>Average</i>	\$ 22.39		<i>Std Dev</i>	0.44%	
Non-Labor O&M	\$13.13	\$ 19.42	\$25.68	\$32.41	\$ 28.60	\$13.00
	<i>Average</i>	\$ 22.04		<i>Std Dev</i>	34.89%	

As illustrated by the small standard deviation of only 0.44%, the Plant's labor-related O&M expenditures are consistent and can be easily projected forward. A cost of \$22.4MM with escalation at 3% through 2041 has been projected, to be consistent with Ameren Missouri's 2010-2014 projections.

The large standard deviation of the non-labor O&M costs illustrates that these costs are not annually consistent. Instead, there is a direct correlation between non-labor O&M

expenses and specific unit outages when determining the amount of costs for any given year. Which years had (or are projected to have) scheduled outages were identified and the non-labor O&M expenses estimated. These costs were then projected forward based on the unit outage schedule provided by Ameren Missouri and the estimate of future outage dates through 2041.

Projecting an average O&M cost going forward is not representative of actual costs to be incurred due to the variations discussed above. Outages for the last few years of the plant's life were omitted in each retirement scenario, assuming that on-line maintenance or short boiler outages would be sufficient to keep the plant running, and there would be no need for any large capital projects. In the years when there is a major boiler outage, the non-labor O&M costs increase significantly over the years where no outages occur.

The differences in the O&M costs from the 2042 retirement case were estimated for 2015, 2016 and 2022 retirement dates and were used in the Midas model for the different Meramec retirement scenarios. The O&M savings for these three retirement dates are presented in Table 4.10. Negative numbers are cost reductions.

Table 4.10 Capital and O&M Savings by Retirement Case (Nominal \$'s)

Million \$'s	Capital Savings				O&M Savings		
	2015	2016	2022		2015	2016	2022
2011	-3	--	--		--	--	--
2012	-12	--	--		-21	-7	--
2013	-37	-37	--		-17	-17	--
2014	-68	-68	--		0	0	--
2015	-10	0	--		-42	0	--
2016	-41	-41	--		-63	-63	--
2017	-78	-78	--		-70	-70	--
2018	-54	-54	-15		-63	-63	--
2019	-11	-11	0		-48	-48	--
2020	-24	-24	-13		-71	-71	-21
2021	-12	-12	0		-51	-51	0
2022	-49	-49	-49		-71	-71	-71
2023	-66	-66	-66		-83	-83	-83
2024	-36	-36	-36		-80	-80	-80
2025	-13	-13	-13		-57	-57	-57
2026	-14	-14	-14		-79	-79	-79
2027	-14	-14	-14		-61	-61	-61
2028	-23	-23	-23		-90	-90	-90
2029	-32	-32	-32		-99	-99	-99
2030	-20	-20	-20		-90	-90	-90

Retirement Cost Amortization

Another input into Midas regarding Meramec retirement scenarios was the net change in depreciation and amortization. The estimated retirement costs are shown in Table 4.11. The amortization period for retirement costs is assumed to be 20 years, and book life for base depreciation expense is 40 years. Amortization of retirement costs and

reduction to depreciation expense are estimated, then the difference between the two is entered into Midas as a net change in depreciation and amortization, which results in higher amortization/depreciation for the first 20 years compared to the continue operations case and lower after that.

Table 4.11 Meramec Retirement Costs

Million \$'s	Current	2015	2016	2022
Net Book Value Writeoff		405,892	406,099	614,477
Asbestos Abatement	8,773	10,170	10,475	12,508
Ash Pond Closure	13,306	15,425	15,888	18,971
Closure of Intake Structure	3,552	4,118	4,242	5,065
Plant Demolition (Net of Salvage)	12,900	14,955	15,403	18,392
Total Retirement Cost	38,531	450,560	452,108	669,414

Transmission

Transmission expenses related to Meramec retirement were not in the scope of the Burns & McDonnell study, so they were developed by Ameren's Transmission Planning group. The transmission modification costs that would be incurred in the retirement cases unless the Meramec site is used for a replacement resource (like Meramec combined cycle) spread over 5 years are:

- **HC**
- **HC**
- **HC**

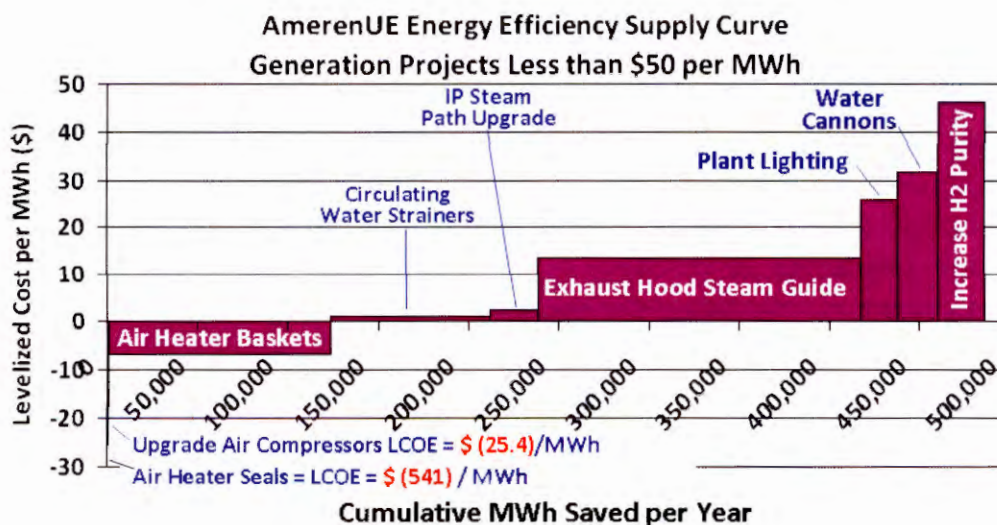
The total estimate of ****HC**** was used in Midas model for the plans that include Meramec retirement without Meramec combined cycle replacing the retired coal plant.

4.5 Existing Plant Efficiency Options²⁰

Ameren Missouri recognized the potential for end-to-end energy efficiency, and engaged EPRI to undertake a study to identify, quantify, and prioritize energy efficiency project opportunities across its operations in electricity generation, transmission, distribution, and utilization at Ameren Missouri facilities.

The team developed profiles of 37 candidate generation project types, which were screened on a unit-by-unit basis on technical applicability. The levelized cost of energy (LCOE) was calculated for the remaining 28 project types after the first screening; Figure 4.3 shows the projects identified that have an LCOE of less than \$50/MWh.

²⁰ 4 CSR 240-22.040(4)

Figure 4.3 Generation Efficiency Projects

There are some efficiency projects currently underway:

- Air heater rebasketing is regularly scheduled at RI and Labadie.
- The Labadie 4 condenser debris filter will be installed in 2011 and the sponge cleaning system restored to service.
- Turbine replants continue as planned.

While it is impossible to implement the projects identified all at once, Ameren Missouri will be assessing and implementing the projects that look feasible on an ongoing basis. The screening analysis was the first step to help prioritize the generation efficiency projects. All of the analysis was based on a generic 500 MW unit characterized by EPRI, and those generic numbers were then scaled to Ameren Missouri's units. The next step is to conduct engineering studies on the most promising projects.

4.6 Power Purchase Agreements

After discussions with Ameren Missouri's Asset Management and Trading organization it was determined that there were no pending potential long-term power purchases for consideration at the time of the analysis. Furthermore, Ameren Missouri learned from its experience in developing the 2008 IRP that soliciting the market for long-term power purchases or sales is not productive for bidders given the data at this stage of the analysis is generic. Evaluation of generic power purchase agreements would not be expected to yield different results in terms of relative performance of resource types, as the only reasonable assumption that could be made absent specific information would be that such an agreement would be cost-based.²¹

²¹ 4 CSR 240-22.040(5)(A-G)

4.7 Supporting Tables

Uncertainty

The characteristic data provided for the candidate technologies were estimated using the best information available at the time of the study; however, there is uncertainty around the key characteristics that are provided. For Ameren Missouri's risk analysis efforts, uncertainties and the respective probabilities for capital costs, fixed and variable O&M costs, forced outage rates and construction time were developed by Black and Veatch and are presented in in Table 4.12. The ranges and probabilities for these variables were used as the basis for development of the uncertain factor sensitivity analysis discussed in Chapter 9.

Table 4.12 Coal and Gas Options Uncertainty Distributions²²

Capital Cost Uncertainty Distribution					
Deviation	-20%	-10%	0%	15%	30%
Probability	5%	25%	40%	25%	5%

Project Schedule Uncertainty Distribution					
Deviation	-30%	-15%	0%	20%	40%
Probability	5%	25%	40%	25%	5%

Fixed O&M Uncertainty Distribution					
Deviation	-20%	-10%	0%	15%	30%
Probability	5%	25%	40%	25%	5%

Variable O&M Uncertainty Distribution				
Combined Cycle				
Deviation	-50%	0%	33%	83%
Probability	25%	45%	25%	5%
Coal w/ CC				
Deviation	-60%	0%	40%	80%
Probability	15%	50%	25%	10%
Simple Cycle				
Deviation	-50%	0%	50%	
Probability	25%	50%	25%	

Forced Outage Uncertainty Distribution			
Combined Cycle			
Deviation	-2%	0%	2%
Probability	25%	50%	25%
Coal w/ CC			
Deviation	-4%	0%	4%
Probability	25%	50%	25%
Simple Cycle			
Deviation	-4%	0%	4%
Probability	25%	50%	25%

Uncertainties around the key characteristics for the nuclear resource option were developed using the uncertainty distribution data from the previous IRP and are presented in the Supporting Tables section in Table 4.13.

²² 4 CSR 240-22.040(8)(B)2; 4 CSR 240-22.040(8)(C)2; 4 CSR 240-22.040(9)(C)

For nuclear project schedule uncertainty, a literature search was conducted in the summer of 2010. Among the results were reports from the US Department of Energy, the International Atomic Energy Agency, and others. These reports listed a variety of actual and planned construction periods in a range of countries including Japan, China, India, Korea, and Finland. When adding the standard 2 years for siting and permitting time obtained from the Black & Veatch study used for other supply side types, the low end for total project schedule was 7 years, the base was 8 years, and the high was 9 years. The 2 year allowance for “preconstruction” within the total project schedule timeframe was consistent with the US Department of Energy report showing 18 months for such activity.

Table 4.13 Nuclear Option Uncertainty Distributions²³

Capital Cost Uncertainty Distribution						
Deviation	-25%	-10%	0%	10%	25%	40%
Probability	5%	10%	50%	20%	10%	5%

Fixed O&M Uncertainty Distribution						
Deviation	-25%	-10%	0%	10%	25%	50%
Probability	5%	20%	40%	20%	10%	5%

Variable O&M Uncertainty Distribution						
Deviation	-25%	-10%	0%	10%	25%	50%
Probability	5%	20%	40%	20%	10%	5%

Forced Outage Uncertainty Distribution			
Deviation	2%	3%	4%
Probability	70%	20%	10%

²³ 4 CSR 240-22.040(8)(B)2; 4 CSR 240-22.040(8)(C)2; 4 CSR 240-22.040(9)(C)

Table 4.14 Candidate Option Model Inputs²⁴

PROJECT TYPE	U.S. EPR	CC02 - USCPC w/ Carbon Capture - Greenfield	A01.2 - CC - Venice 2x1 501F CCCT Conversion	A03.2 - CC - 2x1 501F CCCT - Greenfield	A09.2 - CC - Meramec Unit 4 STG in CCCT Conversion	A16.2 - SC - Two 501Fs w/ SCR - Greenfield
	Base	Base	Intermediate	Intermediate	Intermediate	Peaking
Technology Rating (95 F Day)	1600	679	600	600	834	346
Ramp Up Rate, %/min	5	5	5	5	5	7
Ramp Down Rate, %/min	5	5	5	5	5	7
Minimum Up Time, hours	96	24	8	8	24	1
Minimum Down Time, hours	96	16	8	8	16	1
Equivalent Forced Outage Rate	2%	8%	2%	2%	4%	5%
Startup Fuel, MMBtu or \$	\$381,924	12,400	92	92	138	46 (one CTG)
Fuel Design	Nuclear	PRB Coal	Natural Gas	Natural Gas	Natural Gas	Natural Gas
Capacity Factor	94%	85%	21%	21%	21%	10%
Capital Cost, \$1,000	6,755,200	3,525,760	428,120	690,650	890,560	263,950
Overnight EPC Cost, \$1,000	5,404,160	3,230,000	374,000	650,000	742,000	244,000
Owner Costs excluding AFUDC, \$1,000	1,351,040	295,760	54,120	40,650	148,560	19,950
Capital Cost, \$/kW w/o AFUDC	4,222	5,193	1,686	1,151	1,068	763
Construction Cash Flow, Incremental, % of Capital Cost						
Year 1	6%	0.1%	13%	13%	13%	36%
Year 2	7%	13.9%	30%	30%	30%	51%
Year 3	17%	24%	38%	38%	38%	13%
Year 4	21%	36%	20%	20%	20%	
Year 5	17%	17%				
Year 6	11%	4%				
Year 7	13%	5%				
Year 8	8%	4%				
Fixed O&M Cost, \$/kW-Yr	44.24	37.30	6.80	7.04	6.37	6.89
Variable O&M Cost, \$/MWh	2.01	9.90	3.48	3.65	3.04	12.8
Other O&M Cost		12.45 (1)	3,299 (2)	3,628 (2)	4,455 (2)	1,396 (2)
Polynomial Heat Rate @ 95 F						
Constant (c)	9,788 (3)	-112.4030	71.7295	71.7295	-607.6920	577.8350
1st Term (w)		17.1013	8.1584	8.1584	11.6779	4.8605
2nd Term (x)		-0.0116	-0.0058	-0.0058	-0.0092	0.0239
3rd Term (y)		0.0000	0.0000	0.0000	0.0000	-0.0001
Plant Maintenance Pattern, week/year		4-4-4-6	1-1-2-1-1-6	1-1-2-1-1-6	1-1-2-1-1-6	1-2-1-4
ESTIMATED CONTROLLED EMISSIONS, lbs/MMBtu (HHV)						
NOx	N/A	0.05	0.0075	0.0092	0.0092	0.01
SO2	N/A	0.06	0.0001	0.0006	0.0006	0.0006
CO2	N/A	21.2	117	117	117	117
Hg (percent removal)	N/A	90	N/A	N/A	N/A	N/A

- (1) Carbon sequestration cost - \$/MWh
 (2) Fixed fuel supply cost - \$1,000 per year
 (3) Net Plant Heat Rate (Btu/kWh)

²⁴ 4 CSR 240-22.040(1)(E); 4 CSR 240-22.040(1)(F); 4 CSR 240-22.040(1)(G)

4.8 Compliance References

4 CSR 240-22.040(1)(A)	10
4 CSR 240-22.040(1)(D)	10
4 CSR 240-22.040(1)(E)	11, 22
4 CSR 240-22.040(1)(F).....	22
4 CSR 240-22.040(1)(G).....	22
4 CSR 240-22.040(1)(H)	11
4 CSR 240-22.040(1)(I).....	11
4 CSR 240-22.040(1)(J).....	10
4 CSR 240-22.040(1)(K)2	12
4 CSR 240-22.040(1)(K)3	12
4 CSR 240-22.040(2)(C)	8, 14
4 CSR 240-22.040(3)	12
4 CSR 240-22.040(4)	3, 4, 6, 18
4 CSR 240-22.040(5)(A-G)	19
4 CSR 240-22.040(6)	12
4 CSR 240-22.040(8)(B)1	6
4 CSR 240-22.040(8)(B)2	8, 20, 21
4 CSR 240-22.040(8)(C)1	6
4 CSR 240-22.040(8)(C)2	8, 20, 21
4 CSR 240-22.040(9)(A)3	8
4 CSR 240-22.040(9)(B)	7
4 CSR 240-22.040(9)(C)	20, 21
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Chapter 4 - Appendix A

Fatal Flaw Analysis

Option	Description	Fatal Flaw
Coal	Meramec - Ultra-Supercritical (USC) PC	✓
Coal	Meramec Repowering - Unit 3 Boiler Replacement and STG Rebuild	✓
Coal	Meramec Repowering - Unit 4 Boiler Replacement and STG Rebuild	✓
Coal	Meramec - Oxyfuel Coal with CCC	✓
Coal	Meramec Repowering - Oxyfuel Coal Boiler Replacement	✗
Coal	Meramec - Subcritical CFB	✓
Coal	Meramec Repowering - CFB Boiler Replacement	✗
Coal	Rush Island - USCPC	✓
Coal	Greenfield - USCPC	✓
Coal	Rush Island - Oxyfuel Coal with CCC	✓
Coal	Greenfield - Oxyfuel Coal with CCC	✓
Coal	Rush Island - Integrated Gasification Combined Cycle (IGCC)	✓
Coal	Greenfield - IGCC	✓
Coal	Rush Island - Subcritical CFB	✓
Coal	Greenfield - Subcritical CFB	✓
Coal	Greenfield - Supercritical CFB	✓
Coal	Greenfield - Pressurized Circulating Fluidized Bed (CFB)	✗
Coal	Greenfield - Pressurized Bubbling Fluidized Bed (BFB)	✗
Coal	Greenfield - USCPC with Amine-Based Post-Combustion CCC	✓
Coal	Greenfield - Subcritical CFB with Amine-Based Post-Combustion CCC	✓
Coal	Greenfield - Oxyfuel Coal with CCC	✓
Coal	Greenfield - IGCC with Pre-Combustion CCC	✓
Coal	Efficiency Improvements to Existing Plants – Duct Draft Reductions	✓
Coal	Efficiency Improvements to Existing Plants – Condenser Back-pressure	✓
Gas	Greenfield - CCCT Amine-Based Post-Combustion CCC	✓
Gas	Venice - 2-on-1 501F CCCT Conversion	✓
Gas	Meramec - 2-on-1 501F CCCT	✓
Gas	Greenfield - 2-on-1 501F CCCT	✓
Gas	Goose Creek - Inlet Chilling SCCT Power Augmentation	✓
Gas	Goose Creek - Wetted Media SCCT Power Augmentation	✓
Gas	Mexico - One GE LM6000 Sprint SCCT (5% CF)	✓
Gas	Mexico - One GE LM6000 Sprint SCCT (10% CF)	✓
Gas	Raccoon Creek - One GE 7EA SCCT (5% CF)	✓
Gas	Raccoon Creek - One GE 7EA SCCT (10% CF)	✓
Gas	Meramec Repowering - Unit 3 Boiler NG Conversion	✓

Option	Description	Fatal Flaw
Gas	Meramec Repowering - Unit 4 Boiler NG Conversion	✓
Gas	Meramec Repowering - Unit 4 STG in a 3-on-1 CCCT Conversion	✓
Gas	Meramec Repowering - Unit 3 & Unit 4 STGs in Separate CCCT	✗
Gas	Meramec Repowering - Unit 3 & Unit 4 STGs in a Shared CCCT	✗
Gas	Greenfield - Molten Carbonate Fuel Cell	✓
Gas	Greenfield - Natural Gas Fueled Rankine Cycle	✗
Gas	Greenfield - Twelve Wartsila 20V34SG Simple Cycle Reciprocating	✓
Gas	Greenfield - Two 501F SCCTs (5% CF)	✓
Gas	Greenfield - Two 501F SCCTs (10% CF)	✓
Gas	Greenfield – 2-on-1 Wartsila 20V34SG Combined Cycle Reciprocating	✓
Gas	Greenfield – GE 7EA Cheng Cycle	✓

A high-level fatal flaw analysis was conducted as part of the first stage of the supply-side selection analysis. Options that did not pass the high-level fatal flaw analysis consist of those options that could not be reasonably developed or implemented by Ameren Missouri¹.

Meramec Repowering – Unit 3 & Unit 4 STGs in Separate CCCT Conversions (Option A10)

This option is not feasible because of transmission limitations. The electrical output from the current units is roughly 850 MW. If the Unit 3 and 4 steam turbine generators (STGs) were converted for use in separate combined cycles, the Unit 3 block would produce an estimated net output of 600 to 700 MW, and the Unit 4 block would produce an estimated net output of 800 to 900 MW, for a total net plant output of approximately 1,500 MW. Such an increase in net plant output would likely require major upgrades to the three 138 kV transmission lines tied to Meramec. For the purposes of this study, only the conversion of the Unit 4 STG (Option A09) in a combined cycle was evaluated. If the preliminary characteristics for the Unit 4 STG conversion in a combined cycle option seem promising, then further study could be performed to evaluate the potential for conversion of the Unit 3 STG or Unit 3 and 4 STGs in combined cycles.

Meramec Repowering – Unit 3 & Unit 4 STGs in a Shared CCCT Conversion (Option A11)

This option is not feasible for the same reasons that Option A10 is not feasible.

Greenfield – Natural Gas-Fueled Rankine Cycle (Option A14)

This technology is considered obsolete. Past generation planning efforts have shown this option to be noncompetitive compared with other technologies. Black & Veatch is

¹ 4 CSR 240-22.040(1); 4 CSR 240-22.040(9)(A)3.

not aware of any new projects that were developed with this technology in the recent past.

Meramec – Unit 3 & 4 Boiler Replacement with Oxyfuel Coal Boilers (Option B04)

This option is not feasible because of space requirements and performance impacts. Space available around the Unit 3 and 4 boilers is inadequate for siting of the air separation units (ASUs). On the basis of previous Black & Veatch estimates, the increased auxiliary loading due to the ASUs would reduce the net plant output by approximately 25 percent and would reduce plant efficiency in excess of 10 percentage points.

Meramec – Unit 3 & 4 Boiler Replacement with CFB Boilers (Option B06)

Replacing existing pulverized coal (PC) boilers with new circulating fluidized bed (CFB) boiler would require extensive demolition and modification to the existing units and would most likely result in a reduction in net capacity. A brief summary of issues is listed below:

- CFB boilers have a lower thermal efficiency than PC boilers. Based on previous Black & Veatch estimates, plant efficiency with CFB boilers is typically between 1.0 and 1.5 percentage points lower than that of PC fired facilities.
- A CFB boiler is larger than the existing PC boiler. The cost to modify the existing structure to accommodate CFB boilers would be prohibitive.
- Existing coal preparation equipment would have to be replaced and/or modified.
- New limestone handling and preparation equipment would be required, which would be expensive to site.

Greenfield – Pressurized Circulating Fluidized Bed (Option B13)

At its current developmental status, this technology is not competitive compared with other technologies presented in this effort. No significant development advances have been substantiated in recent years. Limited success with pressurized fluidized bed combustion (PFBC) technology was realized with American Electric Power's Tidd Unit 1, which concluded operations in 1991. More recent pressurized fluidized bed (PFB) projects are currently in operation in Japan, such as Chugoku Electric Power Company's Ohsaki plant, Kyushu Electric Power's Karita plant, and Hokkaido Electric Power Company's Tomatouatsuma plant. Other commercial plants in operation in Europe include Fortum's Vartan plant and E.ON's Escatron plant. A number of operational and performance issues have been experienced with the greatest frequency of incidences occurring in the hot gas cleanup from the PFB to the gas turbine and gas turbine blade deposition, erosion and corrosion due to particulate carry-over in the hot gas path. Due to a relative lack of performance and cost sharing, Black & Veatch is unable to comment on the performance and cost of these projects.

In the United States, recent efforts exploring Advanced PFBC, where the gas turbine is driven partially by hot gases from a pressurized circulating fluidized bed and partially from a topping combustor that receives syngas from a fluidized bed carbonizer (often referred to as a gasifier), have resulted in little progress. In 1990, pilot scale component testing of Advanced PFBC components and systems integration began at the Wilsonville Power Systems Design Facility (PSDF). In 2000, after 170 hours of operation on coal, Foster Wheeler, the major equipment supplier, pulled out of the project and further testing was cancelled. No significant efforts have succeeded this work.

Greenfield – Pressurized Bubbling Fluidized Bed (Option B14)

Similar to Option B13, Option B14 has not been proven competitive.

Compliance References

4 CSR 240-22.040(1)	2
4 CSR 240-22.040(9)(A)3.	2

Chapter 4 - Appendix B

Preliminary Screening Analysis¹

Option	Description	Candidate Option
Coal	Greenfield - IGCC	✓
Coal	Greenfield - IGCC with Pre-Combustion CCC	✓
Coal	Greenfield - Oxyfuel Coal with CCC	✗
Coal	Greenfield - Subcritical CFB	✗
Coal	Greenfield - Subcritical CFB with Amine-Based Post-Combustion CCC	✗
Coal	Greenfield - Supercritical CFB	✗
Coal	Greenfield - USCPC	✓
Coal	Greenfield - USCPC with Amine-Based Post-Combustion CCC	✓
Coal	Meramec - Oxyfuel Coal with CCC	✗
Coal	Meramec - Subcritical CFB	✗
Coal	Meramec - Ultra-Supercritical (USC) PC	✗
Coal	Meramec Repowering - CFB Boiler Replacement	✗
Coal	Meramec Repowering - Oxyfuel Coal Boiler Replacement	✗
Coal	Meramec Repowering - Unit 3 Boiler Replacement and STG	✗
Coal	Meramec Repowering - Unit 4 Boiler Replacement and STG	✗
Coal	Rush Island - Integrated Gasification Combined Cycle (IGCC)	✗
Coal	Rush Island - Oxyfuel Coal with CCC	✗
Coal	Rush Island - Subcritical CFB	✗
Coal	Rush Island - USCPC	✗
Coal	Efficiency Improvements to Existing Plants – Condenser Back-pressure Reductions	✗
Coal	Efficiency Improvements to Existing Plants – Duct Draft	✗
Gas	Goose Creek - Inlet Chilling SCCT Power Augmentation	✗
Gas	Goose Creek - Wetted Media SCCT Power Augmentation	✗
Gas	Greenfield - 2-on-1 501F CCCT	✓
Gas	Greenfield – 2-on-1 Wartsila 20V34SG Combined Cycle	✗
Gas	Greenfield - CCCT Amine-Based Post-Combustion CCC	✗
Gas	Greenfield – GE 7EA Cheng Cycle	✗
Gas	Greenfield - Molten Carbonate Fuel Cell	✗
Gas	Greenfield - Natural Gas Fueled Rankine Cycle	✗
Gas	Greenfield - Twelve Wartsila 20V34SG Simple Cycle	✗
Gas	Greenfield - Two 501F SCCTs (10% CF)	✓

¹ 4 CSR 240-22.040(1)

Option	Description	Candidate Option
Gas	Greenfield - Two 501F SCCTs (5% CF)	✓
Gas	Meramec - 2-on-1 501F CCCT	✓
Gas	Meramec Repowering - Unit 3 & Unit 4 STGs in a Shared CCCT	✗
Gas	Meramec Repowering - Unit 3 & Unit 4 STGs in Separate CCCT	✗
Gas	Meramec Repowering - Unit 3 Boiler NG Conversion	✗
Gas	Meramec Repowering - Unit 4 Boiler NG Conversion	✗
Gas	Meramec Repowering - Unit 4 STG in a 3-on-1 CCCT	✓
Gas	Mexico - One GE LM6000 Sprint SCCT (10% CF)	✓
Gas	Mexico - One GE LM6000 Sprint SCCT (5% CF)	✓
Gas	Raccoon Creek - One GE 7EA SCCT (10% CF)	✓
Gas	Raccoon Creek - One GE 7EA SCCT (5% CF)	✓
Gas	Venice - 2-on-1 501F CCCT Conversion	✓

4.1 Technology Characterization

Following the high-level fatal flaw analysis and elimination of several options, the list of options to be evaluated as part of the second stage of the screening analysis was reduced. Cost, performance, and operating characteristics were developed for each of the remaining options in support of the Preliminary Screening with input from Ameren Missouri and Black & Veatch's internal resources.

All performance and cost estimates were based on technologies fueled by the following design fuels²:

- **Coal** - All coal-fueled options are characterized such that they can operate on either 100 percent Powder River Basin (PRB) coal or 100 percent Illinois Basin No. 6 coal (or on any combination of the two). Thermal performance and emissions estimates for the coal-fueled options assume 100 percent of the feedstock is PRB coal. The air quality control systems (AQCS) for coal-fueled options were selected to achieve target emissions limits for either coal assuming representative fuel properties for Illinois Basin No. 6 coal.
- **Natural Gas** - All gas-fueled options would be designed to operate on pipeline quality natural gas, assumed to be 100 percent methane with 0.2 grain of sulfur per 100 standard cubic feet, unless specified otherwise.

4.1.1 Capacity Ranges

Each of the generation technologies identified in the evaluated options list has sizing limitations. The selection of practical size ranges for each of the technologies is based

² 4 CSR 240-22.040(1)(A)

on Ameren Missouri's ability to plan for and reasonably implement the technology. Table 4.B.1 provides a summary of approximate size limitations for new generation units³.

Table 4.B.1 Capacity Ranges

Technology Description	Single Unit Size	
	Lower Range (MW)	Upper Range (MW)
Ultra-Supercritical PC	500	1,000
Oxyfuel Coal	30	100
Subcritical Circulating Fluidized Bed	100	600
Integrated Gasification Combined Cycle	125	630
Supercritical Circulating Fluidized Bed	100	460
Simple Cycle Combustion Turbine	20	270
Combined Cycle Combustion Turbine	25	1,200
Molten Carbonate Fuel Cells	< 1	3
Simple Cycle Reciprocating Engine	< 1	17
Combined Cycle Reciprocating Engine	18	37

Full load thermal performance and emissions were developed for all evaluated options. Thermal performance was estimated for a 95° F day and a 20° F day. Site conditions were selected to reflect Ameren Missouri's service area. The following elevation and ambient conditions were assumed for all performance estimates:

- Elevation--500 feet above mean sea level.
- 20° F day ambient conditions:
 - Dry bulb temperature--20° F.
 - Relative humidity--60 percent.
- 95° F day ambient conditions:
 - Dry bulb temperature--95° F.
 - Relative humidity--60 percent.

Capacity and performance data for each evaluated option are presented in Table 4.B.12 and Table 4.B.13 under the Supporting Tables section.

4.1.2 Commercial Availability

The commercial status of each of the evaluated technologies was qualitatively assessed. Technology maturity was assessed as either "mature" or "developing."

³ 4 CSR 240-22.040(1)(B)

Technologies defined as mature were those that are proven and well established within the electric power generation industry. Developing technologies consist of all other technologies that may have limited experience, have been utilized in demonstration projects, or consist of laboratory-tested conceptual designs.

4.1.3 Capital Cost Estimates

Screening level, overnight EPC capital cost estimates were developed for all evaluated options and expressed in 2009 dollars. The values presented are reasonable for today's market conditions, but, as demonstrated in recent years, the market is dynamic and unpredictable. Power plant costs are subject to continued volatility and the estimates in this report should be considered primarily for comparative purposes. The EPC costs presented in this report were developed in a consistent manner and are reasonable relative to one another.

The EPC estimates include costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis and are representative of "inside the fence" project scope. The estimates were developed using Black & Veatch proprietary estimating templates and experience. The overall capital cost estimates consist of three main components: EPC Capital Cost, Owner's Cost (excluding AFUDC [Allowance for Funds Used during Construction]), and Owner's AFUDC Cost. Capital costs for all evaluated options are presented in Table 4.B.14 and Table 4.B.15.

An allowance has been made for Owner's costs (excluding AFUDC). Items included in the Owner's costs include "outside the fence" physical assets, project development, and project financing costs. These costs can vary significantly, depending upon technology and unique project requirements. Black & Veatch has developed Owner's costs as a percentage of the EPC capital cost as shown in the tables referenced above. Owner's costs are assumed to include project development costs, interconnection costs, spare parts and plant equipment, project management costs, plant startup/construction support costs, taxes/advisory fees/legal costs, contingency, financing and miscellaneous costs. Table 4.B.2 shows a more detailed explanation of potential owner's costs.

For the purposes of characterizing all of the evaluated options, the AFUDC was calculated by applying the Present Worth Discount Rate (PWDR) over half of the construction duration, with the construction duration being defined as the time period from Notice to Proceed (NTP) to Commercial Operation Date (COD).

Table 4.B.2 Potential Items for Owner's Costs⁴

Project Development: Site selection study Land purchase/options/rezoning Transmission/gas pipeline rights of way Road modifications/upgrades Demolition (if applicable) Environmental permitting/offsets Public relations/community development Legal assistance Utility Interconnections: Natural gas service (if applicable) Gas system upgrades (if applicable) Electrical transmission Supply water Wastewater/sewer (if applicable) Spare Parts and Plant Equipment: Air quality control systems materials, supplies, and parts Acid gas treating materials, supplies and parts Combustion turbine and steam turbine materials, supplies, and parts HRSG materials, supplies, and parts Gasifier materials, supplies, and parts Balance-of-plant equipment materials, supplies and parts Rolling stock Plant furnishings and supplies Operating spares Owner's Project Management: Preparation of bid documents and selection of contractor(s) and suppliers Provision of project management Performance of engineering due diligence Provision of personnel for site construction management	Plant Startup/Construction Support: Owner's site mobilization O&M staff training Supply of trained operators to support equipment testing and commissioning Initial test fluids and lubricants Initial inventory of chemicals/reagents Consumables Cost of fuel not recovered in power sales Auxiliary power purchase Construction all-risk insurance Acceptance testing Taxes/Advisory Fees/Legal: Taxes Market and environmental consultants Owner's legal expenses: • Power Purchase Agreement (PPA) • Interconnect agreements • Contracts--procurement & construction • Property transfer Owner's Contingency: Owner's uncertainty and costs pending final negotiation: • Unidentified project scope increases • Unidentified project requirements • Costs pending final agreement (e.g., interconnection contract costs) Financing: Development of financing sufficient to meet project obligations or obtaining alternate sources of funding Financial advisor, lender's legal, market analyst, and engineer Interest during construction Loan administration and commitment fees Debt service reserve fund Miscellaneous: All costs for above-mentioned Contractor-excluded items, if applicable
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⁴ 4 CSR 240-22.040(3); 4 CSR 240-22.040(6)

4.1.4 Non-Fuel O&M Costs

Nonfuel O&M cost estimates were developed for each of the evaluated options. All O&M cost estimates are presented in Table 4.B.14 and Table 4.B.15. First year O&M costs (in 2009 \$'s) were estimated, and for the future years 3% escalation rate was used.

The modes of dispatch used to establish maintenance intervals for many of the options are as follows:

Baseload Dispatch Profiles – Excluding the IGCC options, all options evaluated at a baseload dispatch mode were assumed to operate at full load at a capacity factor of 85 percent. An IGCC facility is not anticipated to be capable of operating at such a high capacity factor because of the degree of process integration. All IGCC options were assumed to operate at full load at a capacity factor of 80 percent. Options incorporating Carbon Capture and Compression (CCC) were assumed to operate at the same dispatch profile as their non-carbon capture counterparts.

Intermediate Load Dispatch Profiles – Two operating profiles were used for the intermediate load technologies.

- **Profile 1 – Cycling Operation – Off Nights/Off Weekends:** 6 months per year operation at 5 days a week, 8 hours per day in 2x1 combined cycle mode, off-line 16 hours per day and on weekends. Shut down and laid up for 6 winter months per year. Total full load operation of 1,043 hours per year and a capacity factor of about 12 percent.
- **Profile 2 – Cycling Operation – Low Load Nights/Off Weekends:** 6 months per year at 5 days a week, 10 hours per day in 2x1 combined cycle mode, 14 hours per day in 1x1 combined cycle mode at minimum load on the steam turbine, shut down on weekends. Shut down and laid up for 6 winter months per year. This equates to a capacity factor of about 21 percent for the options evaluated in this study.

Peaking Load Dispatch Profiles – All new unit combustion turbine options were evaluated at a peaking dispatch mode, with capacity factors of 5 and 10 percent. It was assumed that 90 starts were associated with a 5 percent capacity factor and 150 starts with a 10 percent capacity factor.

Power augmentation and reciprocating engines operating in simple cycle were evaluated at a 5 percent capacity factor.

4.1.5 Scheduled and Forced Outages

Scheduled maintenance intervals were obtained from original equipment manufacturers (OEMs) or estimated on the basis of Black & Veatch experience for each of the technologies. Where information was not available, maintenance intervals were estimated using data gathered from comparable technologies. These scheduled maintenance patterns were assumed to be the same for technologies employing CCC equipment. The maintenance patterns are presented in Table 4.B.3.

Table 4.B.3 Scheduled Maintenance Outage Patterns⁵

Technology Description	Weeks/Year
Ultra-Supercritical PC (Note 1)	4-4-4-6
Subcritical Circulating Fluidized Bed (Note 2)	3-3-3-3-3-6
Integrated Gasification Combined Cycle (Note 3)	3-3-3-3-3-4
Meramec Repowering - Unit 3 Boiler NG Conversion (Note 4)	3-3-3-6
Meramec Repowering - Unit 4 Boiler NG Conversion (Note 4)	3-3-3-6
Meramec Repowering - Unit 3 Boiler Replacement and STG Rebuild (Note 1)	4-4-4-6
Meramec Repowering - Unit 4 Boiler Replacement and STG Rebuild (Note 1)	4-4-4-6
Meramec Repowering - Unit 4 STG in a CCCT Conversion (Note 5)	1-1-2-1-1-6
Supercritical Circulating Fluidized Bed (Note 2)	3-3-3-3-3-6
Combined Cycle Combustion Turbine (Note 5)	1-1-2-1-1-6
Molten Carbonate Fuel Cells (Note 6)	1
Combined Cycle Reciprocating Engine (Note 7)	2-3-2-3-2-4
Cheng Cycle – 7EA (Note 8)	1-1-2-1-1-4
Siemens 501F (Note 9)	1-2-1-4
GE LM6000 Sprint (Note 10)	1-10
GE 7EA (Note 8)	1-1-2-1-1-4
Goose Creek - Inlet Chilling Augmentation (Note 8)	1-1-2-1-1-4
Goose Creek - Wetted Media Augmentation (Note 8)	1-1-2-1-1-4
Wartsila 20V34SG Reciprocating Engine (Simple Cycle) (Note 7)	2-3-2-3-2-4

Notes:

- (1) 4 week boiler outage every 18 months and a 6 week STG major outage every 6 years.
- (2) 3 week boiler outage every 12 months and a 6 week STG major outage every 6 years.
- (3) Alternating 1 week and 3 week combined cycle outages yearly, alternating 3 week and 2 week gasification outages yearly and a 4 week combined cycle outage every 6 years. This schedule is representative of planned maintenance beginning in year 4. Longer gasification outage durations are expected for years 1 through 3.
- (4) 3 week boiler outage every 18 months and a 6 week STG major outage every 6 years.
- (5) Siemens recommends the following: 1 week combustion inspection every 8,333 eq. hours, 2 week hot gas path inspection every 25,000 eq. hours, and a 4 week major inspection every 50,000 eq. hours for the combustion turbine. A 6 week major outage is recommended at 50,000 eq. hours for the STG.
- (6) Short outages required every 2,000 to 3,000 hours of operation.
- (7) 2 week per 8,000 hours, 3 weeks per 16,000 hours, and 4 weeks per 48,000 hours.

⁵ 4 CSR 240-22.040(1)(G)

(8) GE recommends the following: 1 week combustion inspection every 450 starts, 2 week hot gas path inspection every 1,200 starts, and a 4 week major inspection every 2,400 starts.

(9) Siemens recommends the following: 1 week combustion inspection every 450 starts, 2 week hot gas path inspection every 900 starts, and a 4 week major inspection every 1,800 starts.

(10) GE recommends the following: 1 week hot section rotatable exchange every 25,000 hours and a 10 week (nominal) engine overhaul every 50,000 hours.

Where available, generic equivalent forced outage rate (EFOR) and equivalent demand forced outage rate (EFORd) data were gathered for each of the technologies. The EFOR and EFORd data are presented in Table 4.B.4. The information was taken from the NERC GADS database and published literature to the extent that data were available. When information was not available, values were estimated using data gathered from comparable technologies. EFOR and EFORd were not estimated for technologies employing CCC equipment. For this effort and at this stage of planning, it is assumed that the availability of CCC equipment is independent of the generating facility availability and does not affect EFOR and EFORd. The information is generic, but representative for screening-level supply-side resource analyses.

Table 4.B.4 Forced Outage Rates⁶

Technology Description	EFOR, %	EFORd, %
Ultra-Supercritical PC	8%	8%
Subcritical Circulating Fluidized Bed	11%	10%
Integrated Gasification Combined Cycle	13%	13%
Meramec Repowering - Unit 3 Boiler NG Conversion	8%	7%
Meramec Repowering - Unit 4 Boiler NG Conversion (Note 4)	8%	7%
Meramec Repowering - Unit 3 Boiler Replacement and STG Rebuild	7%	7%
Meramec Repowering - Unit 4 Boiler Replacement and STG Rebuild	7%	7%
Meramec Repowering - Unit 4 STG in a CCCT Conversion	5%	4%
Supercritical Circulating Fluidized Bed	11%	10%
Combined Cycle Combustion Turbine	3%	2%
Molten Carbonate Fuel Cells	2%	2%
Combined Cycle Reciprocating Engine	3%	2%
Cheng Cycle – 7EA	24%	6%
Siemens 501F	17%	5%
GE LM6000 Sprint	11%	6%
GE 7EA	20%	4%
Goose Creek - Inlet Chilling Augmentation	20%	4%
Goose Creek - Wetted Media Augmentation	20%	4%
Wartsila 20V34SG Reciprocating Engine (Simple Cycle)	23%	4%

⁶ 4 CSR 240-22.040(1)(I)

4.1.6 Waste Generation

Wastewater and waste solids must be processed and properly disposed. Technologies fueled by natural gas produce negligible solid waste, but can produce wastewater streams. Coal-fueled technologies produce both wastewater and waste solids. Table 4.B.5 presents a summary of the production of wastewater and solid wastes for the evaluated options.

Table 4.B.5 Waste Generation⁷

Technology Description	Wastewater, gpm	Solid Waste, tons/year
900 MW - Ultra-Supercritical PC	1200	274000
620 MW - Oxyfuel Coal	3300	274000
679 MW - Ultra-Supercritical PC with 90% Post CCC	3300	274000
600 MW - Subcritical Circulating Fluidized Bed	1000	278000
453 MW - Subcritical CFB with 90% Post CCC	2500	278000
562 MW - Integrated Gasification Combined Cycle	900	104000
493 MW – IGCC with 90% Pre CCC 2,400 108,000	2,400	108,000
237 MW - Meramec Repower - U3 Boiler NG Conversion	70	Negligible
332 MW - Meramec Repower - U4 Boiler NG Conversion	100	Negligible
276 MW - Meramec Repower - U3 Boiler Replace and STG Rebuild	70	64,000
369 MW - Meramec Repower - U4 Boiler Replace and STG Rebuild	100	86,000
834 MW - Meramec Repower - U4 STG in a CCCT Conversion	100	Negligible
600 MW - Supercritical Circulating Fluidized Bed	1,000	266,000
600 MW - Combined Cycle Combustion Turbine	750	Negligible
490 MW - CCCT with 90% Post CCC	2,300	Negligible
100 MW - Molten Carbonate Fuel Cells	Negligible	Negligible
17.8 MW - Combined Cycle Reciprocating Engine	10	Negligible
96 MW - Cheng Cycle – 7EA	Negligible	Negligible
346 MW - Siemens 501F	Negligible	Negligible
39.3 MW - Mexico - GE LM6000 Sprint	Negligible	Negligible
73.2 MW - Raccoon Creek - GE 7EA	Negligible	Negligible
54 MW - Goose Creek - Inlet Chilling Augmentation	Negligible	Negligible
18 MW - Goose Creek - Wetted Media Augmentation	Negligible	Negligible
99 MW - Wartsila 20V34SG Reciprocating Engine (Simple Cycle)	Negligible	Negligible

4.1.7 Potentially Useable Byproducts

A variety of solid materials may be generated from the combustion and gasification of coal, including fly ash, bottom ash, byproducts from FGD operation, and byproducts from coal gasification.

⁷ 4 CSR 240-22.040(1)(K)2

- **Fly Ash** – The most widely known uses for fly ash are in the cement and concrete industries. Fly ash has been used extensively for many civil engineering purposes, including structural fill, flowable fill, and road base materials. The use of fly ash is prevalent in road projects where large quantities of suitable soils may not be available. Fly ash has been blended with hydrated lime and aggregated materials to form road base materials that are stronger and more durable than conventional crushed stone or gravel base. Other applications include mineral fillers, mining applications, and agricultural uses.
- **Bottom Ash** – Bottom ash is widely utilized in road bases and structural fill projects. Other applications include use as a sand substitute in cement concrete mixtures, surface material on composition roof shingles, and as an antiskid material applied to roadways in the northeast part of the country.
- **FGD Byproducts** – The primary factor affecting the type of byproduct from lime or limestone-based wet scrubbers is the degree to which oxidation has taken place within the FGD system. If oxidation is promoted, the byproduct will be primarily in the form of calcium sulfate or FGD gypsum. If oxidation is not promoted, much of the product will remain in the calcium sulfite form. In general, FGD gypsum is the more desirable product because it is relatively easy to dewater and can be sold in a variety of re-use markets, such as wallboard production. The minimum purity requirement in the utility industry for marketing FGD gypsum is typically 95 percent or greater.

FGD gypsum is also commonly used in the cement industry. FGD gypsum is used to replace natural gypsum as one of the final steps in the cement manufacturing process. As with wallboard, the gypsum must be free from contamination and consistent in composition. FGD gypsum has also been used successfully as an engineered material in structural fills and road bases. Gypsum is commonly used as an agricultural additive for soils deficient in calcium and sulfur. The use of FGD gypsum as a substitute for natural gypsum in agricultural applications is somewhat more flexible than in wallboard and cement manufacture because less stringent specifications on sulfite, ash, and chloride content can be tolerated.

- **Coal Gasification Byproducts** – The IGCC technology evaluated in this study employs a Claus sulfur recovery plant from which liquid elemental sulfur is recovered. This sulfur is commonly used in a variety of industries such as the rubber industry, fertilizer manufacturing, oil refining, wastewater processing, and mineral extraction. The gasifier produces a molten slag that flows freely into a water-filled compartment at the bottom of the gasifier. As the molten slag contacts the water bath, the slag vitrifies into dense, glassy granules. The vitrified

slag produced by the gasifiers can be used for the fabrication of ceramic products.

4.1.8 Coal Technology Options

Ultra-Supercritical (USC) Pulverized Coal (PC)

The following assumptions have been made for all ultra-supercritical PC options:

1. Single unit site, with a capacity of 900 MW net (nominal).
2. USC TC4F STG and USC PC boiler.
3. AQCS:
 - Low nitrogen oxide (NO_x) burners and selective catalytic reduction (SCR) for nitrogen oxides (NO_x) control.
 - Wet flue gas desulfurization (FGD) for sulfur dioxide (SO_2) control.
 - Activated carbon injection for mercury control.
 - Pulse-jet fabric filter for particulate matter (PM10) control.
 - Sorbent injection for sulfur trioxide (SO_3) control.
4. Turbine driven boiler feed pumps.
5. Throttle conditions – 3,800 psia (pounds per square inch absolute)/1,110° F main steam/1,110° F reheat.
6. Single reheat steam cycle.
7. Eight feedwater heaters – Three high-pressure (HP), four low-pressure (LP), and one deaerator (DA).
8. Ultra-supercritical PC options that employ carbon dioxide (CO_2) capture and compression (CCC) would utilize an amine-based chemical solvent to remove 90 percent of the CO_2 from the flue gas stream. Staged compression would deliver the CO_2 to the site boundary at a pressure of 2,200 psig (pounds per square inch gauge). CO_2 transportation and sequestration are evaluated separately.

Oxyfuel Coal

The following assumptions have been made for all oxyfuel coal options:

1. Single unit site, with a fuel flow rate equal to the fuel flow rate for the ultra-supercritical PC plant (Refer to Section 3.2.1).
2. USC TC4F STG and USC PC boiler.
3. AQCS:
 - Low NO_x burners and SCR for NO_x control.
 - Wet FGD for SO_2 control.
 - Activated carbon injection for mercury control.
 - Pulse-jet fabric filter for particulate control.
 - Sorbent injection for SO_3 control.

- 90 percent of the flue stream would be compressed and delivered to the site boundary at a pressure of 2,200 psig. CO₂ transportation and sequestration are evaluated separately.

4. Flue gas recycle.

5. Air Separation Unit (ASU) – 95 percent oxygen (O₂) purity.

6. Turbine driven boiler feed pumps.

7. Throttle conditions – 3,800 psia/1,110° F/1,110° F.

8. Single reheat steam cycle.

9. Eight feedwater heaters – Three HP, four LP, and one DA.

Circulating Fluidized Bed (CFB)

The following assumptions have been made for all CFB options:

1. Single unit site, with a capacity of 2 x 300 MW net (nominal) boilers and 1 x 600 MW net (nominal) TC4F STG.

2. AQCS:

- Combustion controls and selective noncatalytic reduction (SNCR) for NO_x control
- Boiler limestone injection and polishing spray dry absorber for polishing SO₂/SO₃ control.
- Activated carbon injection for mercury control.
- Pulse-jet fabric filter for particulate control.

3. Motor driven boiler feed pumps.

4. Single reheat steam cycle.

5. Eight feedwater heaters – Three HP, four LP, and one DA.

6. A mechanical-draft, counterflow, cooling tower assumed for heat rejection.

7. CFB options that employ CCC would utilize an amine-based chemical solvent to remove 90 percent of the CO₂ from the flue gas stream. Staged compression would deliver the CO₂ to the site boundary at a pressure of 2,200 psig. CO₂ transportation and sequestration are evaluated separately.

Subcritical CFB

1. Subcritical STG and subcritical CFB boilers.

2. Throttle conditions – 2,415 psia/1,050° F/1,050° F.

Supercritical CFB

1. Supercritical STG and supercritical CFB boilers.

2. Throttle conditions – 3,800 psia/1,050° F/1,050° F.

Integrated Gasification Combined Cycle (IGCC)

The following assumptions have been made for all integrated gasification combined cycle (IGCC) options:

1. Two 50 percent dry fed, entrained-flow Shell Coal Gasification Process gasifiers.
2. Two General Electric (GE) 7FB⁸ combustion turbine generators (CTGs) with syngas combustors.
3. Two 50 percent ASUs – 95 percent O₂ purity.
4. One subcritical TC2F STG.
5. Two triple-pressure heat recovery steam generators (HRSGs).
6. AQCS:
 - Nitrogen diluent, syngas saturation, and SCR for NO_x control.
 - Carbonyl sulfide (COS) hydrolysis, Selexol acid gas removal (AGR), and Claus sulfur recovery unit (SRU) with tailgas recycle for SO₂ control and sulfur recovery.
 - Candle filter for particulate control.
 - Sulfided carbon bed adsorption for mercury control.
7. Inlet air evaporative cooling above 59° F.
8. A mechanical-draft, counterflow, cooling tower assumed for heat rejection.
9. No duct firing for the HRSG(s).
10. IGCC options that employ CCC would utilize a Genosorb physical solvent CO₂ removal process to remove 90 percent of the CO₂ from the syngas stream. Rather than a Selexol process, options that employ CCC would utilize an MDEA (methyl diethanolamine) acid gas removal process. Staged compression would deliver the CO₂ to the site boundary at a pressure of 2,200 psig. CO₂ transportation and sequestration are evaluated separately.

Efficiency Improvements – Duct Draft Reductions⁹

The electrical auxiliary loads required to drive the forced draft (FD) and induced draft (ID) fans are significant in a PC plant. Any reductions in air handling system pressure loss will reduce the required auxiliary loads and, therefore, increase the net plant output (NPO).

One method of calculating reduced pressure loss potential in the air handling system is to perform cold flow modeling. According to Pollution Control Services, Inc. (PCS), implementing modifications identified from modeling flows from the boiler economizer through the SCR, air heater, ESP/baghouse, scrubber, ID fans and stack will typically result in overall static loss reductions of 3 to 8 inches of water column (in-wc). Using the information provided by PCS, Black & Veatch made a conservative assumption that five

⁸ Future offerings will be presented as “7FA Syngas.”

⁹ 4 CSR 240-22.040(4)

flow correction devices could be installed in each Ameren Missouri PC unit. Flow correction devices attempt to restrict or divert the flows in an attempt to achieve more uniform flow distribution and lower pressure drop. Some examples of flow correction devices include turning vanes, splitters, egg crates, and perforated plates.

Assuming an average static loss reduction of 0.4 in-wc per flow correction device results in an overall pressure loss reduction of 2.0 in-wc per unit. A reduction in pressure loss would result in auxiliary load savings through the ID fan(s), increasing net output. Using Ameren Missouri unit operating data, Black & Veatch estimated ID fan auxiliary load savings for a 2.0 in-wc pressure drop reduction for Rush Island Unit 2. The performance gains realized at Rush Island Unit 2 are representative of a ~ 600 MW pulverized coal unit.

An order-of-magnitude capital cost estimate was developed using information provided by PCS and recent Black & Veatch experience with such flow correction devices. PCS suggested budget cost of \$400,000 to \$500,000 for 1:12 scale cold flow modeling of Rush Island Units 1 and 2. Translated roughly, this equates to about \$250,000 for cold flow modeling at Rush Island Unit 2 only. Recent installations of flow correction devices in nominal 500 MW – 600 MW pulverized coal plants have ranged in cost from approximately \$40,000 to \$65,000 per flow correction device. With the fixed expense of cold flow modeling, modifications made to the larger units will most likely be the most economical.

Efficiency Improvements – Condenser Back-Pressure Reductions¹⁰

The performance of a condenser impacts STG performance, thereby, affecting unit performance. Unit performance can be improved by increasing the condenser cleanliness factors for plants utilizing once-through cooling systems. Debris filters can reduce macro fouling and tubesheet pluggage in the condenser. Two types of debris filters may be applied:

- In-line debris filter – placed in the circulating water pipe near the condenser waterbox.
- Intake debris filter – placed at the intake structure and intended to replace the traveling screens.

Costs for intake debris filters were developed for this analysis. The capital cost requirements are greater for intake debris filters than for in-line debris filters. However, with the implementation of in-line debris filters, it is recommended that traveling screens remain in service. Traveling screens tend to have significant problems with carryover of debris and are maintenance intensive. Intake debris filters are intended to replace

¹⁰ 4 CSR 240-22.040(4)

traveling screens, likely reducing total system maintenance requirements and improving overall unit reliability.

Black & Veatch believes that implementation of a condenser ball cleaning system, in conjunction with debris filters, is the best approach to realizing significant condenser performance improvements.

Black & Veatch spoke with Ameren Missouri engineers and utilized on-line Ameren Missouri unit operating data and equipment design information to develop a performance impact estimate for Rush Island Unit 2. A cost estimate for the intake debris filters and condenser ball cleaning systems was developed from multiple vendor budgetary quotations. The performance impact estimate represents average condenser cleanliness factor increases of 25 percentage points for each hour Rush Island Unit 2 would operate above the design condenser backpressure assuming an existing condenser cleanliness factor of 60 percent. The performance and cost estimates for Rush Island Unit 2 are representative of a ~ 600 MW pulverized coal unit.

4.1.9 Natural Gas Technology Options

Meramec Unit 4 STG in Combined Cycle Conversion

The reuse of Unit 4's STG as part of a combined cycle was included as an alternative to replacing Units 1 through 4 with an entirely new unit at Meramec. Reuse of the Unit 4 STG would entail the addition of three CTGs, each fitted with a Heat Recovery Steam Generator (HRSG). Steam produced in the HRSGs would be sent to the Unit 4 STG. Each of the HRSGs would be outfitted with duct firing to fully utilize the STG capacity. The following assumptions have been made for the Meramec Unit 4 STG combined cycle conversion option:

1. Three Siemens 501F CTGs and three HRSGs supplying steam to the existing Unit 4 STG.
2. AQCS:
 - Dry low NO_x burners and SCR for NO_x control.
 - CO oxidation catalyst for carbon monoxide (CO) and volatile organic compounds (VOC) controls.
3. Inlet air evaporative cooling above 59° F.
4. Duct firing during hot day conditions to match the design limits of the Unit 4 STG.
5. Triple-pressure HRSGs.
6. No HRSG bypass dampers and stacks included.
7. Existing equipment removed from service:
 - Unit 4 boiler.
 - Unit 4 feedwater heaters.
 - Unit 4 boiler feed pump(s).
 - Existing Unit 4 feedwater and steam piping.

- Plant control system.
 - Unit 4 electrostatic precipitator (ESP).
 - Unit 4 coal and limestone handling equipment.
 - Units 1 through 3 in their entirety.
8. Equipment reused in combined cycle conversion:
- Unit 4 STG.
 - Unit 4 STG control system.
 - Unit 4 gland steam condenser.
 - Unit 4 gland steam regulator.
 - Unit 4 condenser.
9. Scope of work needed to refurbish reused equipment:
- STG intermediate pressure (IP) retrofit.
 - STG high pressure (HP) stator rewind and rotor replacement.
 - STG low pressure (LP) stator rewind and rotor replacement.
 - STG static excitation retrofit.
 - Condenser retubing.

Meramec Boiler Conversion to Natural Gas

The following scope of work applies to the Meramec Unit 3 and 4 options in which the boilers would be converted to burn natural gas:

1. Burner replacement.
2. Reheater modifications.
3. Superheater modifications.
4. Desuperheater spray modifications.
5. Air heater modifications.
6. Boiler controls modifications.

Meramec Boiler Replacements and STG Rebuilds

The following scope of work applies to the Meramec Unit 3 and 4 options in which the boilers would be replaced and the STG sets would be refurbished:

1. Boiler - New waterwalls.
2. Boiler - Major superheater and reheater retrofits.
3. Steam piping modifications (main steam, cold reheat, and hot reheat).
4. Feedwater system modifications.
5. Hot well pump overhaul.
6. DA replacement (excluding DA storage tank).
7. One feedwater heater replacement.
8. Condenser retubing.
9. Induced draft fan motor and rotor modifications.
10. Water cannon replacement.

11. Unit-specific bottom ash system.
12. Fly ash collection system.
13. Significant structural steel modifications.
14. Demolition.
15. STG intermediate pressure (IP) retrofit.
16. STG high pressure (HP) stator rewind and rotor replacement.
17. STG low pressure (LP) stator rewind and rotor replacement.
18. STG static excitation retrofit.

Combined Cycle

Performance, emissions, and cost estimates were prepared for the following combined cycle technology:

- 2-on-1 Siemens combined cycle based on a Siemens 501F CTG.

The following assumptions have been made for all combined cycle options:

1. Two CTGs, two HRSGs, and one TC2F STG.
2. AQCS:
 - Dry low NO_x burners and SCR for NO_x control.
 - CO oxidation catalyst for CO and VOC controls.
3. Inlet air evaporative cooling above 59° F.
4. Duct firing during hot day conditions to match 600 MW net plant output.
5. Triple-pressure HRSGs.
6. A mechanical-draft, counterflow, cooling tower assumed for heat rejection.
7. No HRSG bypass dampers and stacks.
8. Combined cycle options that employ CCC would utilize an amine-based chemical solvent to remove 90 percent of the CO₂ from the flue gas stream. Staged compression would deliver the CO₂ to the site boundary at a pressure of 2,200 psig. CO₂ transportation and sequestration are evaluated separately.

Venice Combined Cycle Conversion

Performance, emissions, and cost estimates were developed as part of a separate study conducted by Black & Veatch for Ameren Missouri. The conversion of Venice units 3 and 4 from two Siemens Westinghouse 501F combustion turbines to a 2-on-1 combined cycle required the following additional systems:

- Two HRSGs and one TC2F STG.
- Duct firing during hot day conditions to match the 600 MW net plant output.
- Triple-pressure HRSGs.
- A mechanical-draft, plume abated cooling tower assumed for heat rejection.

The conversion of two simple cycle combustion turbines into a 2-on-1 combined cycle block represents a net capacity increase. In addition, the combined cycle would likely be dispatched more frequently than the current simple cycles, resulting in a net increase in fuel consumption and operations expenses. For screening purposes, the Venice combined cycle conversion option is treated as an incremental capacity increase to exiting Venice Units 3 and 4 with fuel burn rate and fixed and non-fuel variable O&M estimates equal to the entire 2-on-1 combined cycle block. For modeling purposes, the Venice combined cycle conversion is treated as a 2-on-1 combined cycle block. All model runs with the Venice combined cycle block exclude the existing Unit 3 and 4 simple cycles. All model runs with the existing Unit 3 and 4 simple cycles exclude the Venice combined cycle block.

Fuel Cell

Performance, emissions, and cost estimates were prepared for the following fuel cell technology:

- Generic, molten carbonate fuel cells.

The following assumptions have been made for the gas-fueled fuel cell facility:

1. Thirty-six (36) 2.8 MW (net, nominal) fuel cell packages.

Combined Cycle Reciprocating Engines

Performance, emissions, and cost estimates were prepared for the following reciprocating engine technology:

- Wärtsilä 20V34SG

The following assumptions have been made for the gas-fueled combined cycle reciprocating engine facility:

1. NO_x reduction would be achieved through use of a urea-based SCR system located in the HRSGs.
2. The power block would consist of two 20V34SG engines, one nonreheat STG, and two HRSGs.
3. A mechanical-draft, counterflow cooling tower would be included.

Cheng Cycle

Performance, emissions, and cost estimates were prepared for the following combustion turbine technology:

- GE 7EA

The following assumptions have been made for the gas-fueled Cheng Cycle facility:

1. The power block would consist of one modified GE 7EA CTG and one HRSG.
2. Emissions would be controlled through the use of Cheng Low NO_x (CLN) combustion with steam/fuel premixing.
3. Power augmentation would be achieved through use of the Advanced Cheng System (ACS) and Cheng Boost steam injection.

Simple Cycle

Performance, emissions, and cost estimates were prepared for the following simple cycle technologies:

- Large Frame – Siemens 501F.
- Small Frame – GE 7EA.
- Aeroderivative – GE LM6000 SPRINT.

The following assumptions have been made for all simple cycle options:

1. Dry low NO_x (DLN) burners would be included for NO_x control.
2. Units that are dispatched at a capacity factor of 5 percent would not include an SCR system or CO oxidation catalyst.
3. Units that are dispatched at a capacity factor of 10 percent would include an SCR system and CO oxidation catalyst.

Existing Simple Cycle Fleet Power Augmentation¹¹

Characteristics for simple cycle power augmentation options were developed as part of a separate study conducted by Black and Veatch. The objective of this study was to identify a single preferred power augmentation technology for the block of turbines located at each facility. The study considered the following commercially available power augmentation technologies:

- Wetted Media Evaporative Cooling.
- Inlet Fogging Evaporative Cooling.
- Wet Compression.
- Inlet Chilling.
- Inlet Chilling with Thermal Storage.
- Water Injection.
- Steam Injection.
- GE SPRINT Package.

In total, 38 CTs distributed among seven sites were analyzed to determine the feasibility of installing various commercially available power augmentation technologies. The results of the power augmentation technology screening are presented in Table 4.B.6.

¹¹ 4 CSR 240-22.040(4)

Table 4.B.6 CTG Power Augmentation Summary of Results

Facility	Number of Units	Preferred Power Augmentation	Potential Unit Net Capacity Increase, MW	Potential Site Net Capacity Increase, MW	Incremental Capital Cost, \$/kW
Audrain	8	Inlet Chilling	8.4	67.2	850
Goose Creek	6	Wetted Media	3	18	150
	6	Inlet Chilling	11	66	600
Kinmundy	2	None	N/A	N/A	N/A
Peno Creek	4	Inlet Chilling	5	20	1,200
Pinckneyville 1-4	4	SPRINT	6	16	300
		Package			
Pinckneyville 5-8	4	Inlet Fogging	2	8	150
	4	Inlet Chilling	5	20	850
Raccoon Creek	4	Inlet Chilling	8	32	900
Venice 2	1	Inlet Chilling	5	5	1,200
Venice 5	1	None	N/A	N/A	N/A

The two options included from that study were selected on the basis of cost of power and capacity addition potential. The first option selected is the addition of wetted media (commonly referred to as evaporative cooling) to six GE 7EA combustion turbines at Ameren Missouri's Goose Creek facility. The second option selected is the addition of inlet chilling to the 7EAs at Goose Creek. The first power augmentation option offers the lowest cost on a dollar per kW basis at \$150/kW with 3MW capacity increase on each of the six units. However, the second option offers a more substantial capacity increase- a total increase of 66 MW, but at a higher cost- \$600/MW.

Reciprocating Engines (Simple Cycle)

Performance, emissions, and cost estimates were prepared for the following reciprocating engine technology:

- Wärtsilä 20V34SG

The following assumptions have been made for the gas-fueled reciprocating engine facility:

1. Units would be dispatched at a low capacity factor that would preclude SCR.
2. The power block would consist of twelve 20V34SG engines, for a 100 MW net (nominal) output.

No additional operational characteristics, constraints or siting impacts that could affect the screening results were identified. By the same token, no other technology