ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070098-EI
FLORIDA POWER & LIGHT COMPANY

IN RE: FLORIDA POWER & LIGHT COMPANY'S PETITION TO DETERMINE NEED FOR FPL GLADES POWER PARK UNITS 1 AND 2 ELECTRICAL POWER PLANT

CMP ____
COM 5
CTR ____
ECR ____
GCL 1
OPC 1
RCA ____
SCR ____
SGA ____
SEC ____
OTH PIF

NEED STUDY FOR ELECTRICAL POWER

APPENDICES A-O

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Appendix A

Major FPL Interconnections (2012-2016)

List of FPL Major Interconnections (230 KV and 500 KV)

FPL	PEF[1/]	KV
Poinsett	Holopaw	230
Sanford Plant	North Longwood	230
Sanford Plant	Debary	230
Sanford Plant	Altamonte	230
Whidden	Vandolah	230
Charlotte	Vandolah	230
Poinsett	Bithlo (2009)	230
Sanford	Bithlo (2009)	230
FPL	**TECO[1/]**	**KV**
Ringling	Big Bend	230
Manatee	Big Bend	230
Manatee	Ruskin	230
FPL	**JEA[1/]**	**KV**
Duval	Brandy Branch (3 circuits)	230
FPL120G1	Switzerland	230
FPL	**OUC[1/]**	**KV**
Cape Canaveral	Indian River (2 circuits)	230
FPL	**SECI[1/]**	**KV**
Calusa	Lee (2 circuits)	230
Rice	Seminole Plant (2 circuits)	230
Putnam	Seminole Plant	230
Duval	Seminole Plant	230
FPL	**FMPA[1/]**	**KV**
Orangedale	Sampson	230
Duval	Greencove	230
FPL120G1	Sampson	230
Ralls	FMP-TCEC (2008)	230
FPL	**SOCO[1/]**	**KV**
Duval	Hatch	500
Duval	Thalman	500
Yulee	Kingsland	230

Note:

1/ PEF: Progress Energy Florida
TECO: Tampa Electric Company
JEA: Jacksonville Electric Authority
OUC: Orlando Utilities Commission
SECI: Seminole Electric Cooperative, Inc.
FMPA: Florida Municipal Power Authority
SOCO: Southern Company

Appendix B

FPL Generation Facilities

(Projected 2007)

Plant Name	Unit No.	Location	Unit Type	Fuel: Primary	Fuel: Alternative	Net Capability 1/ Winter MW	Net Capability 1/ Summer MW
Cape Canaveral	1	Brevard County	Steam	Heavy Oil	Natural Gas	403	399
	2		Steam	Heavy Oil	Natural Gas	403	399
Cutler	5	Miami Dade County	Steam	Natural Gas	None	67	65
	6		Steam	Natural Gas	None	109	105
Fort Myers	2	Lee County	Combined Cycle	Natural Gas	None	1,610	1,441
	3A & B		Combustion Turbine	Natural Gas	Distillate Oil	380	326
	1-12		Gas Turbine	Distillate Oil	None	769	648
Lauderdale	4	Broward County	Combined Cycle	Natural Gas	Distillate Oil	465	428
	5		Combined Cycle	Natural Gas	Distillate Oil	464	428
	1-12		Gas Turbine	Natural Gas	Distillate Oil	509	420
	13-24		Gas Turbine	Natural Gas	Distillate Oil	509	420
Manatee	1	Manatee County	Steam	Heavy Oil	Natural Gas	817	825
	2		Steam	Heavy Oil	Natural Gas	817	825
	3		Combined Cycle	Natural Gas	None	1,197	1,114
Martin	1	Martin County	Steam	Heavy Oil	Natural Gas	830	838
	2		Steam	Heavy Oil	Natural Gas	829	831
	3		Combined Cycle	Natural Gas	None	471	460
	4		Combined Cycle	Natural Gas	None	472	461
	8		Combined Cycle	Natural Gas	Distillate Oil	1,197	1,115
Port Everglades	1	City of Hollywood	Steam	Heavy Oil	Natural Gas	220	219
	2		Steam	Heavy Oil	Natural Gas	220	219
	3		Steam	Heavy Oil	Natural Gas	382	393
	4		Steam	Heavy Oil	Natural Gas	390	395
	1-12		Gas Turbine	Natural Gas	Distillate Oil	509	420
Putnam	1	Putnam County	Combined Cycle	Natural Gas	Distillate Oil	282	249
	2		Combined Cycle	Natural Gas	Distillate Oil	286	249
Riviera	3	City of Riviera Beach	Steam	Heavy Oil	Natural Gas	274	276
	4		Steam	Heavy Oil	Natural Gas	286	284
Sanford	3	Volusia County	Steam	Heavy Oil	Natural Gas	142	138
	4		Combined Cycle	Natural Gas	None	1,045	966
	5		Combined Cycle	Natural Gas	None	1,045	962
Scherer 2/	4	Monroe, GA	Bituminous Coal	Bituminous Coal	None	642	658
St. Johns River Power Park 3/	1	Duval County	Bituminous Coal	Bituminous Coal	Petroleum Coke	130	127
	2		Bituminous Coal	Bituminous Coal	Petroleum Coke	112	127
St. Lucie 4/	1	St. Lucie County	Nuclear	Uranium	None	853	839
	2		Nuclear	Uranium	None	726	714
Turkey Point	1	Miami Dade County	Steam	Heavy Oil	Natural Gas	388	398
	2		Steam	Heavy Oil	Natural Gas	403	400
	3		Nuclear	Uranium	None	717	693
	4		Nuclear	Uranium	None	717	693
	5		Combined Cycle	Natural Gas	None	1,181	1,144
	1-5		Internal Combustion	Distillate Oil	None	12	12

1/ These ratings are peak capability.

2/ These ratings represent Florida Power & Light Company's share of Scherer Unit No. 4, adjusted for transmission losses.

3/ The net capability ratings represent Florida Power & Light Company's share of St. Johns River Park Unit No. 1 and No. 2, excluding Jacksonville Electric Authority (JEA) share of 80%.

4/ Total capability is 853/839 MW. Capabilities shown represnet FPL's share of the unit and exclude the Orlando Utilities Commission (OUC) and Florida Municipal Power Agency (FMPA) combined portion of approximately 15%.

Appendix C

Computer Models Used in FPL's Resource Planning*

TIGER

TIGER, the "Tie Line Assistance and Generation Reliability" program, is a model originally developed by Florida Power Corporation. The model has been modified by FPL and is used to determine the magnitude and the timing of FPL's resource needs. The system reliability analyses performed by TIGER are based on three planning criteria: 20% minimum Summer reserve margin, 20% minimum Winter reserve margin, and a maximum loss-of-load probability (LOLP) of 0.1 days/year.

TIGER is a program capable of modeling two geographic areas. FPL models its service territory (and its connections to other utilities) as a single area. The expected assistance levels from other utility systems are modeled as an additional generator within FPL's service territory.

TIGER performs the calculations of excess firm capacity at the times of the annual system peaks (i.e., reserve margin calculations). It performs these calculations for the Winter peak (January) and the Summer peak (August). TIGER checks the Winter and Summer reserve margins to determine if additional capacity is needed to meet FPL's reserve margin criteria.

In addition, TIGER performs the calculation of LOLP by looking at the peak demand for each day of the year, while taking into consideration the unavailability of generators due to planned/scheduled maintenance or forced outages. Therefore, 365 daily peaks (366 for leap years) are used to calculate annual LOLP values.

* FPL regularly utilizes other models in various aspects of its integrated resource planning (IRP) work. The models listed here were used in analyses leading directly to this Determination of Need filing.

P-MArea

P-MArea is a detailed, hourly production costing model developed by P-Plus Corporation. The model has been used extensively for developing the information used in FPL's Fuel Cost Recovery filings and in numerous fuel-related studies including FPL's 2005 Clean Coal Report as well as in the analyses for the Determination of Need filing for the two West County Energy Center combined cycle units.

In regard to the current Determination of Need filing for the two advanced technology coal units at FPL's Glades Power Park site, P-MArea was used to develop production costs (fuel, variable O&M, and system emission costs) for the two resource plans for all of the fuel cost and environmental compliance cost forecast scenarios. The model also used transmission transfer limits in order to capture the impacts on system production costs of the geographic location of the new generation resources included in each of the resource plans.

Fixed Cost Spreadsheet

The Fixed Cost Spreadsheet is an FPL spreadsheet designed to capture all fixed costs associated with a resource plan. Fixed costs addressed include: generator capital, capacity payments, fixed O&M, capital replacement, transmission interconnection & integration capital, firm gas transportation costs, fuel inventory-related costs, upstream gas costs, etc. The Fixed Cost Spreadsheet was used in the analyses for the Determination of Need filing for the two West County Energy Center combined cycle units.

In regard to the current Determination of Need filing for the two advanced technology coal units at FPL's Glades Power Park site, the Fixed Cost Spreadsheet was used to calculate all fixed costs associated with the two resource plans. These fixed costs, when combined with the production costs developed with P-MArea, provided FPL with a complete perspective of the system costs associated with each resource plan.

MetrixND

MetrixND is an advanced statistics program for analysis and forecasting of time-series data that is stored in Excel or Access databases. This statistical package is used to develop the regression models to forecast sales, net energy for load, and peak demand.

Residential Sales Regression Model

Residential energy sales are forecast by multiplying the projected residential use per customer by the projected number of residential customers. A regression model is used to project the electric usage per customer. The regression model utilizes the following explanatory variables: real residential price of electricity, Florida Real Personal Income, Cooling and Heating Degree Days, and dummy variables for hurricanes and historical periods.

Commercial Sales Regression Model

The commercial sales forecast is also developed using a regression model. The regression model utilizes the following explanatory variables: Gross Domestic Product, commercial real price of electricity, Cooling Degree Days, and dummy variables for hurricanes and historical periods.

Industrial Sales Linear Multiple Regression Model

Industrial sales were forecasted using a linear multiple regression model. The linear multiple regression model utilizes the following explanatory variables: Gross Domestic Product, Cooling Degree Days, and several dummy variables for outliers, hurricanes, and months.

Net Energy for Load (NEL) Regression Model

An econometric model is developed to produce a Net Energy for Load (NEL) forecast. The explanatory variables used in the model are the following: total customers, the real price of electricity, Heating and Cooling Degree days, and Florida Real Personal Income.

System Summer Peak Econometric Model

The Summer peak forecast is developed using an econometric regression model. This econometric model utilizes the following explanatory variables: total average customers, the real price of electricity, Florida Real Personal Income, average temperature on peak day, and a heat buildup weather factor consisting of the sum of the Cooling Degree Hours during the peak day and three prior days.

System Winter Peak Econometric Model

The Winter peak forecast is developed using the same econometric regression methodology as is used for Summer peak forecasts. The Winter peak model is a per customer model which contains the following explanatory variables: the square of the minimum temperature on the peak day and Heating Degree Hours for the prior day as well as for the morning of the Winter peak day. The model also includes an economic variable: Florida Real Personal Income.

The Hourly Load Forecast: System Load Forecasting "Shaper" Program

Forecasted values for system hourly load are produced using a System Load Forecasting "Shaper" Program. This model uses 16 years of historical FPL hourly system load data to develop load shapes for weekdays, weekend days, and holidays. The model allows calibration of hourly values where the peak is maintained or where both the peak and minimum load-to-peak ratio is maintained.

Appendix D

FPL's Forecast of Peak Demands and Net Energy for Load (NEL)

Annual Peaks

Year	January (Winter) MW	August (Summer) MW	Net Energy for Load GWH
2007	22,247	22,259	117,551
2008	22,627	22,770	122,024
2009	23,115	23,435	126,270
2010	23,587	24,003	130,499
2011	24,047	24,612	134,766
2012	24,498	25,115	139,038
2013	24,952	25,590	142,379
2014	25,416	26,100	146,257
2015	26,048	26,772	150,291
2016	26,692	27,410	154,556
2017	27,342	28,079	158,179
2018	27,994	28,737	162,140
2019	28,649	29,391	166,097
2020	29,308	30,091	170,661
2021	29,936	30,780	174,470
2022	30,562	31,466	178,576
2023	31,191	32,160	182,763
2024	31,826	32,859	187,465
2025	32,475	33,581	191,516
2026	33,123	34,290	195,831
2027	33,772	35,007	200,204
2028	34,422	35,731	205,080
2029	35,084	36,474	209,257
2030	35,750	37,219	213,798
2031	36,416	37,964	218,372

Annual Peaks

Year	January (Winter) MW	August (Summer) MW	Net Energy for Load GWH
2032	37,086	38,716	223,527
2033	37,773	39,480	227,829
2034	38,480	40,279	232,681
2035	39,205	41,084	237,670
2036	39,943	41,909	243,334
2037	40,670	42,720	247,895
2038	41,443	43,588	251,835
2039	42,235	44,478	257,105
2040	43,047	45,393	263,219

Note: For the analyses discussed in this Determination of Need filing, it was assumed that the load was held constant for the years 2040 through 2054. Therefore, the 2040 forecast values shown above were also used for each year in the 2041 through 2054 time period.

Appendix E

Fuel Cost Forecast 1 (High Price): Natural Gas

YEAR	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	ZONE 3 FGT FIRM $/MMBTU	ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	GULFSTREAM FIRM - SESH PIPELINE $/MMBTU	GULFSTREAM FIRM - MOBILE BAY $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	GULFSTREAM NON-FIRM BACKHAUL $/MMBTU	UPS REPLACEMENT $/MMBTU	WILLIAMS - TRANSCO ZONE 4 $/MMBTU	PROGRESS $/MMBTU	HENRY HUB $/MMBTU
2006	$10.38	$10.51	$10.96	$11.06	$11.34		$10.85	$11.71	$12.15		$10.35	$10.30	$10.17
2007	$11.52	$11.66	$12.06	$12.18	$12.67		$11.94	$12.80	$13.38		$11.54	$12.13	$11.23
2008	$11.93	$12.06	$12.37	$12.41	$12.91	$11.30	$12.17	$13.03	$13.60		$11.93	$12.55	$11.62
2009	$10.24	$10.38	$10.68	$10.69	$11.18	$10.06	$10.47	$11.33	$11.90		$11.47	$10.79	$9.99
2010	$9.46	$9.60	$9.94	$9.95	$10.44	$9.29	$9.74	$10.61	$11.17	$9.40			$9.23
2011	$8.56	$8.70	$9.06	$9.06	$9.56	$8.40	$8.87	$9.74	$10.30	$8.59			$8.36
2012	$8.95	$9.09	$9.41	$9.41	$9.90	$8.78	$9.21	$10.08	$10.64	$8.98			$8.74
2013	$9.21	$9.35	$9.66	$9.66	$10.15	$9.04	$9.46	$10.33	$10.89	$9.23			$8.99
2014	$9.46	$9.60	$9.89	$9.89	$10.39	$9.29	$9.69	$10.56	$11.12	$9.48			$9.23
2015	$9.94	$10.08	$10.38	$10.38	$10.87	$9.76	$10.17	$11.03	$11.60	$9.96			$9.70
2016	$10.57	$10.71	$11.01	$11.01	$11.51	$10.39	$10.79	$11.65	$12.22	$10.59			$10.31
2017	$11.36	$11.50	$11.80	$11.80	$12.30	$11.17	$11.57	$12.43	$13.00	$11.37			$11.07
2018	$12.16	$12.29	$12.59	$12.60	$13.09	$11.96	$12.35	$13.21	$13.78	$12.16			$11.85
2019	$12.96	$13.09	$13.39	$13.40	$13.89	$12.75	$13.14	$14.00	$14.57	$12.96			$12.62
2020	$13.76	$13.90	$14.20	$14.20	$14.70	$13.55	$13.93	$14.79	$15.37	$13.75			$13.40
2021	$14.20	$14.33	$14.63	$14.63	$15.13	$13.97	$14.35	$15.22	$15.79				$13.82
2022	$14.64	$14.78	$15.08	$15.08	$15.57	$14.42	$14.79	$15.65	$16.23				$14.26
2023	$15.10	$15.23	$15.53	$15.53	$16.03	$14.87	$15.24	$16.10	$16.68				$14.70
2024	$15.57	$15.70	$16.00	$16.01	$16.50	$15.33	$15.70	$16.56	$17.14				$15.15
2025	$16.08	$16.22	$16.52	$16.52	$17.02	$15.84	$16.21	$17.07	$17.65				$15.65
2026	$16.57	$16.71	$17.01	$17.01	$17.51	$16.33	$16.69	$17.55	$18.14				$16.13
2027	$17.08	$17.21	$17.51	$17.52	$18.01	$16.83	$17.19	$18.05	$18.63				$16.62
2028	$17.60	$17.73	$18.03	$18.04	$18.53	$17.34	$17.70	$18.56	$19.14				$17.12
2029	$18.14	$18.27	$18.57	$18.57	$19.07	$17.88	$18.22	$19.09	$19.67				$17.64
2030	$18.69	$18.83	$19.13	$19.13	$19.62	$18.43	$18.77	$19.63	$20.22				$18.18
2031	$19.26	$19.40	$19.70	$19.70	$20.20	$18.99	$19.33	$20.20	$20.79				$18.74
2032	$19.85	$19.99	$20.29	$20.29	$20.79	$19.58	$19.91	$20.78	$21.37				$19.31
2033	$20.46	$20.60	$20.90	$20.90	$21.39	$20.18	$20.51	$21.37	$21.97				$19.90
2034	$21.09	$21.22	$21.52	$21.53	$22.02	$20.80	$21.13	$21.99	$22.58				$20.51
2035	$21.73	$21.87	$22.17	$22.17	$22.66	$21.43	$21.76	$22.62	$23.22				$21.13
2036	$22.40	$22.53	$22.84	$22.84	$23.33	$22.10	$22.42	$23.28	$23.88				$21.78
2037	$23.09	$23.22	$23.52	$23.52	$24.02	$22.78	$23.09	$23.96	$24.55				$22.45
2038	$23.79	$23.92	$24.23	$24.23	$24.72	$23.47	$23.78	$24.65	$25.25				$23.13
2039	$24.51	$24.65	$24.95	$24.95	$25.45	$24.19	$24.49	$25.36	$25.96				$23.83
2040	$25.26	$25.39	$25.69	$25.69	$26.19	$24.93	$25.23	$26.09	$26.69				$24.55
2041	$26.02	$26.16	$26.46	$26.46	$26.95	$25.68	$25.98	$26.84	$27.45				$25.29
2042	$26.81	$26.94	$27.24	$27.25	$27.74	$26.46	$26.75	$27.61	$28.22				$26.05
2043	$27.62	$27.75	$28.06	$28.06	$28.55	$27.26	$27.55	$28.41	$29.02				$26.84
2044	$28.45	$28.59	$28.89	$28.89	$29.39	$28.09	$28.37	$29.23	$29.84				$27.65
2045	$29.31	$29.45	$29.75	$29.75	$30.25	$28.94	$29.21	$30.08	$30.69				$28.48
2046	$30.20	$30.33	$30.63	$30.63	$31.13	$29.81	$30.08	$30.94	$31.56				$29.34
2047	$31.11	$31.24	$31.54	$31.54	$32.04	$30.72	$30.98	$31.84	$32.46				$30.22
2048	$32.04	$32.18	$32.48	$32.48	$32.98	$31.64	$31.90	$32.76	$33.38				$31.13
2049	$33.01	$33.14	$33.44	$33.44	$33.94	$32.60	$32.84	$33.71	$34.33				$32.07
2050	$34.00	$34.13	$34.43	$34.44	$34.93	$33.58	$33.82	$34.68	$35.31				$33.03
2051	$35.02	$35.15	$35.46	$35.46	$35.95	$34.59	$34.82	$35.69	$36.32				$34.02
2052	$36.07	$36.21	$36.51	$36.51	$37.01	$35.63	$35.86	$36.72	$37.35				$35.04
2053	$37.15	$37.29	$37.59	$37.59	$38.08	$36.70	$36.92	$37.78	$38.42				$36.09
2054	$38.27	$38.40	$38.70	$38.70	$39.20	$37.80	$38.01	$38.88	$39.51				$37.17

Fuel Cost Forecast 1 (High Price): Solid Fuel

YEAR	PLANT SCHERER DISPATCH PRICE WITHOUT SO2 $/MMBTU	ST. JOHNS RIVER POWER PARCK DISPATCH PRICE WITHOUT SO2 $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 $/MMBTU	FGPP DISPATCH PRICE WITHOUT SO2 $/MMBTU
2006	$2.58	$2.38	$4.25	$2.75	$3.78
2007	$2.53	$1.82	$3.81	$2.24	$3.29
2008	$2.30	$1.78	$3.64	$2.20	$3.20
2009	$2.26	$1.86	$3.63	$2.23	$3.26
2010	$2.21	$1.87	$3.62	$2.21	$3.26
2011	$2.27	$1.90	$3.66	$2.24	$3.31
2012	$2.32	$1.95	$3.72	$2.27	$3.38
2013	$2.37	$2.00	$3.77	$2.30	$3.44
2014	$2.41	$2.06	$3.81	$2.36	$3.50
2015	$2.74	$2.10	$3.87	$2.41	$3.56
2016	$2.78	$2.15	$3.96	$2.48	$3.64
2017	$2.82	$2.20	$4.07	$2.54	$3.72
2018	$2.87	$2.25	$4.18	$2.61	$3.80
2019	$2.92	$2.31	$4.30	$2.70	$3.90
2020	$2.97	$2.38	$4.42	$2.78	$3.99
2021	$3.02	$2.43	$4.53	$2.85	$4.08
2022	$3.07	$2.49	$4.64	$2.92	$4.17
2023	$3.12	$2.55	$4.75	$2.99	$4.26
2024	$3.16	$2.60	$4.87	$3.05	$4.35
2025	$3.21	$2.65	$5.06	$3.11	$4.47
2026	$3.27	$2.70	$5.19	$3.16	$4.56
2027	$3.32	$2.75	$5.32	$3.21	$4.65
2028	$3.37	$2.79	$5.46	$3.26	$4.75
2029	$3.43	$2.84	$5.60	$3.32	$4.85
2030	$3.48	$2.90	$5.75	$3.38	$4.95
2031	$3.55	$2.95	$5.90	$3.44	$5.06
2032	$3.61	$3.01	$6.05	$3.51	$5.17
2033	$3.67	$3.07	$6.21	$3.57	$5.28
2034	$3.74	$3.13	$6.38	$3.64	$5.39
2035	$3.81	$3.19	$6.55	$3.71	$5.51
2036	$3.88	$3.27	$6.72	$3.80	$5.64
2037	$3.95	$3.34	$6.90	$3.89	$5.77
2038	$4.02	$3.42	$7.08	$3.98	$5.90
2039	$4.09	$3.50	$7.27	$4.07	$6.03
2040	$4.17	$3.58	$7.47	$4.17	$6.16
2041	$4.25	$3.66	$7.67	$4.26	$6.30
2042	$4.32	$3.75	$7.87	$4.36	$6.44
2043	$4.40	$3.83	$8.09	$4.46	$6.59
2044	$4.49	$3.92	$8.31	$4.56	$6.73
2045	$4.57	$4.01	$8.54	$4.67	$6.89
2046	$4.65	$4.11	$8.77	$4.78	$7.04
2047	$4.74	$4.20	$9.02	$4.89	$7.20
2048	$4.83	$4.30	$9.27	$5.00	$7.37
2049	$4.92	$4.40	$9.52	$5.12	$7.54
2050	$5.01	$4.50	$9.79	$5.24	$7.71
2051	$5.10	$4.60	$10.07	$5.36	$7.89
2052	$5.20	$4.71	$10.35	$5.48	$8.07
2053	$5.30	$4.82	$10.64	$5.61	$8.26
2054	$5.40	$4.93	$10.94	$5.74	$8.45

Fuel Cost Forecast 1 (High Price): Residual Fuel Oil

YEAR	MARTIN 1% $/MMBTU	PORT EVERGLADES 1% $/MMBTU	MANATEE 1% $/MMBTU	TURKEY POINT 1% $/MMBTU	INDIAN RIVER & CANAVERAL 1% $/MMBTU	SANFORD 1% $/MMBTU	RIVIERA 1% $/MMBTU
2006	$11.03	$10.98	$11.00	$11.01	$10.97	$11.49	$10.97
2007	$10.50	$10.50	$10.50	$10.52	$10.50	$10.88	$10.50
2008	$12.05	$12.05	$12.05	$12.07	$12.06	$12.43	$12.05
2009	$11.44	$11.44	$11.44	$11.46	$11.44	$11.82	$11.44
2010	$11.31	$11.31	$11.32	$11.33	$11.32	$11.69	$11.31
2011	$11.01	$11.00	$11.01	$11.03	$11.01	$11.38	$11.01
2012	$11.63	$11.63	$11.64	$11.65	$11.64	$12.01	$11.63
2013	$11.55	$11.55	$11.56	$11.57	$11.56	$11.93	$11.55
2014	$11.48	$11.47	$11.48	$11.49	$11.48	$11.85	$11.48
2015	$11.96	$11.96	$11.96	$11.98	$11.97	$12.34	$11.96
2016	$12.83	$12.83	$12.84	$12.85	$12.84	$13.21	$12.83
2017	$13.72	$13.71	$13.72	$13.73	$13.72	$14.09	$13.72
2018	$14.63	$14.63	$14.63	$14.65	$14.64	$15.01	$14.63
2019	$15.57	$15.57	$15.58	$15.59	$15.58	$15.95	$15.57
2020	$16.52	$16.51	$16.52	$16.54	$16.52	$16.90	$16.52
2021	$17.00	$17.00	$17.00	$17.02	$17.00	$17.38	$17.00
2022	$17.49	$17.49	$17.50	$17.51	$17.50	$17.87	$17.49
2023	$18.00	$18.00	$18.00	$18.02	$18.01	$18.38	$18.00
2024	$18.53	$18.52	$18.53	$18.55	$18.53	$18.90	$18.53
2025	$19.09	$19.09	$19.10	$19.11	$19.10	$19.47	$19.09
2026	$19.64	$19.64	$19.64	$19.66	$19.65	$20.02	$19.64
2027	$20.20	$20.20	$20.20	$20.22	$20.21	$20.58	$20.20
2028	$20.78	$20.78	$20.78	$20.80	$20.79	$21.16	$20.78
2029	$21.38	$21.37	$21.38	$21.40	$21.38	$21.76	$21.38
2030	$21.99	$21.99	$21.99	$22.01	$22.00	$22.37	$21.99
2031	$22.63	$22.62	$22.63	$22.65	$22.63	$23.00	$22.63
2032	$23.28	$23.28	$23.28	$23.30	$23.29	$23.66	$23.28
2033	$23.95	$23.95	$23.95	$23.97	$23.96	$24.33	$23.95
2034	$24.64	$24.64	$24.64	$24.66	$24.65	$25.02	$24.64
2035	$25.35	$25.35	$25.35	$25.37	$25.36	$25.73	$25.35
2036	$26.09	$26.08	$26.09	$26.11	$26.09	$26.46	$26.09
2037	$26.84	$26.84	$26.84	$26.86	$26.85	$27.22	$26.84
2038	$27.61	$27.61	$27.62	$27.63	$27.62	$27.99	$27.61
2039	$28.41	$28.41	$28.41	$28.43	$28.42	$28.79	$28.41
2040	$29.23	$29.22	$29.23	$29.24	$29.23	$29.60	$29.23
2041	$30.06	$30.06	$30.07	$30.08	$30.07	$30.44	$30.06
2042	$30.93	$30.92	$30.93	$30.95	$30.93	$31.31	$30.93
2043	$31.82	$31.81	$31.82	$31.83	$31.82	$32.19	$31.82
2044	$32.73	$32.73	$32.73	$32.75	$32.73	$33.11	$32.73
2045	$33.67	$33.67	$33.67	$33.69	$33.67	$34.05	$33.67
2046	$34.63	$34.63	$34.63	$34.65	$34.64	$35.01	$34.63
2047	$35.63	$35.62	$35.63	$35.64	$35.63	$36.00	$35.63
2048	$36.65	$36.64	$36.65	$36.67	$36.65	$37.02	$36.65
2049	$37.70	$37.69	$37.70	$37.71	$37.70	$38.07	$37.70
2050	$38.78	$38.78	$38.78	$38.80	$38.78	$39.16	$38.78
2051	$39.89	$39.89	$39.89	$39.91	$39.89	$40.27	$39.89
2052	$41.03	$41.03	$41.03	$41.05	$41.04	$41.41	$41.03
2053	$42.20	$42.20	$42.21	$42.22	$42.21	$42.58	$42.20
2054	$43.41	$43.41	$43.41	$43.43	$43.42	$43.79	$43.41

Fuel Cost Forecast 1 (High Price): Distillate Oil

YEAR	SHADY HILLS $/MMBTU	DESOTO $/MMBTU	OLEANDER $/MMBTU	PORT EVERGLADES $/MMBTU	LAUDERDALE $/MMBTU	FT MYERS $/MMBTU	PUTNAM $/MMBTU	MARTIN & WCEC $/MMBTU
2006	$19.84	$19.89	$19.92	$19.39	$19.39	$20.09	$20.07	$19.97
2007	$19.48	$19.58	$19.63	$18.78	$18.78	$19.48	$19.73	$19.68
2008				$19.26	$19.26	$19.96	$20.21	$20.16
2009				$17.57	$17.57	$18.27	$18.52	$18.47
2010				$17.45	$17.45	$18.15	$18.40	$18.35
2011				$15.46	$15.46	$16.16	$16.41	$16.36
2012				$16.35	$16.35	$17.05	$17.30	$17.25
2013				$16.56	$16.56	$17.26	$17.51	$17.46
2014				$16.73	$16.73	$17.43	$17.68	$17.63
2015				$17.46	$17.46	$18.16	$18.41	$18.36
2016				$18.52	$18.52	$19.22	$19.47	$19.42
2017				$19.62	$19.62	$20.33	$20.58	$20.53
2018				$20.72	$20.72	$21.43	$21.68	$21.63
2019				$21.88	$21.88	$22.58	$22.83	$22.78
2020				$23.02	$23.02	$23.72	$23.97	$23.92
2021				$23.65	$23.66	$24.35	$24.60	$24.55
2022				$24.29	$24.29	$24.99	$25.25	$25.20
2023				$24.96	$24.96	$25.66	$25.91	$25.86
2024				$25.64	$25.64	$26.34	$26.59	$26.54
2025				$26.37	$26.37	$27.07	$27.32	$27.27
2026				$27.08	$27.08	$27.78	$28.04	$27.99
2027				$27.82	$27.82	$28.52	$28.77	$28.72
2028				$28.57	$28.57	$29.27	$29.52	$29.47
2029				$29.34	$29.34	$30.04	$30.29	$30.24
2030				$30.14	$30.14	$30.84	$31.09	$31.04
2031				$30.96	$30.96	$31.66	$31.91	$31.86
2032				$31.81	$31.81	$32.51	$32.76	$32.71
2033				$32.67	$32.67	$33.37	$33.62	$33.57
2034				$33.56	$33.56	$34.26	$34.51	$34.46
2035				$34.48	$34.48	$35.18	$35.43	$35.38
2036				$35.42	$35.42	$36.12	$36.37	$36.32
2037				$36.39	$36.39	$37.09	$37.34	$37.29
2038				$37.38	$37.38	$38.09	$38.34	$38.29
2039				$38.40	$38.40	$39.10	$39.36	$39.31
2040				$39.45	$39.45	$40.15	$40.40	$40.35
2041				$40.52	$40.52	$41.23	$41.48	$41.43
2042				$41.63	$41.63	$42.33	$42.58	$42.53
2043				$42.76	$42.76	$43.46	$43.71	$43.66
2044				$43.93	$43.93	$44.63	$44.88	$44.83
2045				$45.12	$45.12	$45.83	$46.08	$46.03
2046				$46.35	$46.35	$47.05	$47.30	$47.25
2047				$47.62	$47.62	$48.32	$48.57	$48.52
2048				$48.91	$48.91	$49.61	$49.87	$49.82
2049				$50.25	$50.25	$50.95	$51.20	$51.15
2050				$51.62	$51.62	$52.32	$52.57	$52.52
2051				$53.02	$53.02	$53.73	$53.98	$53.93
2052				$54.47	$54.47	$55.17	$55.42	$55.37
2053				$55.95	$55.95	$56.65	$56.91	$56.86
2054				$57.48	$57.48	$58.18	$58.43	$58.38

Fuel Cost Forecast 2 (Shocked Medium Price): Natural Gas

YEAR	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	ZONE 3 FGT FIRM $/MMBTU	ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	GULFSTREAM FIRM - SESH PIPELINE $/MMBTU	GULFSTREAM FIRM - MOBILE BAY $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	GULFSTREAM NON-FIRM BACKHAUL $/MMBTU	UPS REPLACEMENT $/MMBTU	WILLIAMS - TRANSCO ZONE 4 $/MMBTU	PROGRESS $/MMBTU	HENRY HUB $/MMBTU
2006	$13.18	$13.35	$13.92	$14.05	$14.41		$13.78	$14.88	$15.43		$13.15	$13.09	$12.91
2007	$14.63	$14.81	$15.32	$15.47	$16.10		$15.17	$16.26	$16.99		$14.66	$15.40	$14.26
2008	$15.15	$15.32	$15.71	$15.77	$16.39	$14.35	$15.45	$16.55	$17.28		$15.15	$15.94	$14.76
2009	$13.01	$13.18	$13.57	$13.57	$14.20	$12.78	$13.30	$14.40	$15.12		$14.57	$13.70	$12.69
2010	$12.02	$12.19	$12.63	$12.63	$13.26	$11.80	$12.37	$13.47	$14.19	$11.94			$11.73
2011	$10.88	$11.06	$11.50	$11.51	$12.14	$10.67	$11.27	$12.37	$13.08	$10.91			$10.62
2012	$11.37	$11.54	$11.95	$11.95	$12.58	$11.16	$11.70	$12.80	$13.52	$11.40			$11.10
2013	$11.70	$11.87	$12.27	$12.27	$12.90	$11.48	$12.02	$13.12	$13.83	$11.73			$11.42
2014	$12.02	$12.19	$12.56	$12.57	$13.20	$11.80	$12.31	$13.41	$14.13	$12.05			$11.73
2015	$12.63	$12.80	$13.18	$13.18	$13.81	$12.40	$12.92	$14.01	$14.73	$12.65			$12.32
2016	$13.43	$13.60	$13.98	$13.99	$14.62	$13.20	$13.71	$14.80	$15.52	$13.45			$13.09
2017	$11.14	$11.27	$11.57	$11.57	$12.05	$10.95	$11.34	$12.19	$12.74	$11.15			$10.86
2018	$8.39	$8.49	$8.69	$8.70	$9.04	$8.26	$8.52	$9.12	$9.52	$8.39			$8.18
2019	$8.95	$9.04	$9.25	$9.25	$9.59	$8.80	$9.07	$9.66	$10.06	$8.94			$8.71
2020	$9.50	$9.59	$9.80	$9.80	$10.15	$9.35	$9.61	$10.21	$10.61	$9.49			$9.25
2021	$9.80	$9.89	$10.10	$10.10	$10.44	$9.65	$9.91	$10.50	$10.90				$9.54
2022	$10.11	$10.20	$10.41	$10.41	$10.75	$9.95	$10.21	$10.81	$11.20				$9.84
2023	$10.42	$10.51	$10.72	$10.72	$11.07	$10.26	$10.52	$11.12	$11.51				$10.14
2024	$10.75	$10.84	$11.05	$11.05	$11.39	$10.58	$10.84	$11.43	$11.83				$10.46
2025	$11.10	$11.20	$11.40	$11.41	$11.75	$10.94	$11.19	$11.78	$12.19				$10.81
2026	$11.44	$11.53	$11.74	$11.74	$12.09	$11.27	$11.52	$12.12	$12.52				$11.13
2027	$11.79	$11.88	$12.09	$12.09	$12.43	$11.62	$11.86	$12.46	$12.86				$11.47
2028	$12.15	$12.24	$12.45	$12.45	$12.79	$11.97	$12.22	$12.81	$13.22				$11.82
2029	$12.52	$12.61	$12.82	$12.82	$13.16	$12.34	$12.58	$13.18	$13.58				$12.18
2030	$12.90	$13.00	$13.20	$13.21	$13.55	$12.72	$12.96	$13.55	$13.96				$12.55
2031	$13.30	$13.39	$13.60	$13.60	$13.94	$13.11	$13.35	$13.94	$14.35				$12.93
2032	$13.71	$13.80	$14.01	$14.01	$14.35	$13.51	$13.75	$14.34	$14.75				$13.33
2033	$14.12	$14.22	$14.43	$14.43	$14.77	$13.93	$14.16	$14.76	$15.16				$13.74
2034	$14.56	$14.65	$14.86	$14.86	$15.20	$14.36	$14.58	$15.18	$15.59				$14.16
2035	$15.00	$15.09	$15.30	$15.30	$15.65	$14.80	$15.02	$15.62	$16.03				$14.59
2036	$15.46	$15.56	$15.76	$15.77	$16.11	$15.25	$15.47	$16.07	$16.48				$15.03
2037	$15.94	$16.03	$16.24	$16.24	$16.58	$15.72	$15.94	$16.54	$16.95				$15.49
2038	$16.42	$16.52	$16.72	$16.73	$17.07	$16.20	$16.42	$17.01	$17.43				$15.97
2039	$16.92	$17.01	$17.22	$17.22	$17.57	$16.70	$16.91	$17.51	$17.92				$16.45
2040	$17.44	$17.53	$17.74	$17.74	$18.08	$17.21	$17.41	$18.01	$18.43				$16.95
2041	$17.96	$18.06	$18.26	$18.27	$18.61	$17.73	$17.93	$18.53	$18.95				$17.46
2042	$18.51	$18.60	$18.81	$18.81	$19.15	$18.27	$18.47	$19.06	$19.48				$17.99
2043	$19.07	$19.16	$19.37	$19.37	$19.71	$18.82	$19.02	$19.61	$20.03				$18.53
2044	$19.64	$19.74	$19.94	$19.95	$20.29	$19.39	$19.58	$20.18	$20.60				$19.09
2045	$20.24	$20.33	$20.54	$20.54	$20.88	$19.98	$20.17	$20.76	$21.19				$19.66
2046	$20.84	$20.94	$21.15	$21.15	$21.49	$20.58	$20.77	$21.36	$21.79				$20.25
2047	$21.47	$21.57	$21.77	$21.78	$22.12	$21.20	$21.38	$21.98	$22.41				$20.86
2048	$22.12	$22.21	$22.42	$22.42	$22.76	$21.84	$22.02	$22.62	$23.04				$21.49
2049	$22.78	$22.88	$23.09	$23.09	$23.43	$22.50	$22.67	$23.27	$23.70				$22.14
2050	$23.47	$23.56	$23.77	$23.77	$24.12	$23.18	$23.35	$23.94	$24.37				$22.80
2051	$24.18	$24.27	$24.48	$24.48	$24.82	$23.88	$24.04	$24.64	$25.07				$23.48
2052	$24.90	$24.99	$25.20	$25.20	$25.55	$24.60	$24.75	$25.35	$25.78				$24.19
2053	$25.65	$25.74	$25.95	$25.95	$26.29	$25.34	$25.49	$26.08	$26.52				$24.91
2054	$26.42	$26.51	$26.72	$26.72	$27.06	$26.10	$26.24	$26.84	$27.28				$25.66

Fuel Cost Forecast 2 (Shocked Medium Price): Solid Fuel

YEAR	PLANT SCHERER DISPATCH PRICE WITHOUT SO2 $/MMBTU	ST. JOHNS RIVER POWER PARCK DISPATCH PRICE WITHOUT SO2 $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 $/MMBTU	FGPP DISPATCH PRICE WITHOUT SO2 $/MMBTU
2006	$2.18	$2.01	$3.59	$2.32	$3.19
2007	$2.13	$1.54	$3.22	$1.89	$2.77
2008	$1.94	$1.50	$3.07	$1.86	$2.70
2009	$1.91	$1.57	$3.07	$1.88	$2.75
2010	$1.87	$1.58	$3.05	$1.86	$2.76
2011	$1.91	$1.61	$3.09	$1.89	$2.80
2012	$1.96	$1.65	$3.14	$1.92	$2.85
2013	$2.00	$1.69	$3.18	$1.95	$2.90
2014	$2.03	$1.74	$3.22	$1.99	$2.96
2015	$2.31	$1.77	$3.27	$2.04	$3.01
2016	$2.35	$1.81	$3.35	$2.09	$3.07
2017	$2.38	$1.85	$3.44	$2.15	$3.14
2018	$2.42	$1.90	$3.53	$2.21	$3.21
2019	$2.47	$1.95	$3.63	$2.28	$3.29
2020	$2.51	$2.01	$3.73	$2.35	$3.37
2021	$2.55	$2.05	$3.82	$2.41	$3.45
2022	$2.59	$2.10	$3.92	$2.47	$3.52
2023	$2.63	$2.15	$4.01	$2.52	$3.60
2024	$2.67	$2.19	$4.11	$2.57	$3.67
2025	$2.71	$2.24	$4.28	$2.63	$3.77
2026	$2.76	$2.28	$4.38	$2.67	$3.85
2027	$2.80	$2.32	$4.49	$2.71	$3.93
2028	$2.85	$2.35	$4.61	$2.75	$4.01
2029	$2.89	$2.40	$4.73	$2.80	$4.09
2030	$2.94	$2.44	$4.85	$2.85	$4.18
2031	$2.99	$2.49	$4.98	$2.90	$4.27
2032	$3.05	$2.54	$5.11	$2.96	$4.36
2033	$3.10	$2.59	$5.24	$3.02	$4.46
2034	$3.16	$2.64	$5.39	$3.08	$4.55
2035	$3.21	$2.70	$5.53	$3.14	$4.65
2036	$3.27	$2.76	$5.67	$3.21	$4.76
2037	$3.33	$2.82	$5.82	$3.28	$4.87
2038	$3.39	$2.89	$5.98	$3.36	$4.98
2039	$3.46	$2.95	$6.14	$3.44	$5.09
2040	$3.52	$3.02	$6.31	$3.52	$5.20
2041	$3.58	$3.09	$6.47	$3.60	$5.32
2042	$3.65	$3.16	$6.65	$3.68	$5.44
2043	$3.72	$3.24	$6.83	$3.77	$5.56
2044	$3.79	$3.31	$7.02	$3.85	$5.68
2045	$3.86	$3.39	$7.21	$3.94	$5.81
2046	$3.93	$3.47	$7.40	$4.03	$5.94
2047	$4.00	$3.55	$7.61	$4.13	$6.08
2048	$4.08	$3.63	$7.82	$4.22	$6.22
2049	$4.15	$3.71	$8.04	$4.32	$6.36
2050	$4.23	$3.80	$8.27	$4.42	$6.51
2051	$4.31	$3.88	$8.50	$4.52	$6.66
2052	$4.39	$3.97	$8.74	$4.63	$6.82
2053	$4.47	$4.06	$8.98	$4.73	$6.97
2054	$4.56	$4.16	$9.24	$4.84	$7.14

Fuel Cost Forecast 2 (Shocked Medium Price): Residual Fuel Oil

YEAR	MARTIN 1% $/MMBTU	PORT EVERGLADES 1% $/MMBTU	MANATEE 1% $/MMBTU	TURKEY POINT 1% $/MMBTU	INDIAN RIVER & CANAVERAL 1% $/MMBTU	SANFORD 1% $/MMBTU	RIVIERA 1% $/MMBTU
2006	$12.21	$12.15	$12.17	$12.19	$12.14	$12.72	$12.14
2007	$11.62	$11.61	$11.62	$11.64	$11.62	$12.03	$11.62
2008	$13.34	$13.33	$13.34	$13.36	$13.34	$13.75	$13.34
2009	$12.65	$12.65	$12.66	$12.68	$12.66	$13.07	$12.65
2010	$12.52	$12.52	$12.52	$12.54	$12.52	$12.94	$12.52
2011	$12.18	$12.18	$12.18	$12.20	$12.18	$12.60	$12.18
2012	$12.87	$12.87	$12.88	$12.89	$12.88	$13.29	$12.87
2013	$12.78	$12.78	$12.79	$12.80	$12.79	$13.20	$12.78
2014	$12.70	$12.69	$12.70	$12.72	$12.70	$13.12	$12.70
2015	$13.23	$13.23	$13.24	$13.25	$13.24	$13.65	$13.23
2016	$14.20	$14.20	$14.20	$14.22	$14.21	$14.62	$14.20
2017	$12.51	$12.51	$12.52	$12.53	$12.52	$12.86	$12.51
2018	$10.51	$10.51	$10.51	$10.53	$10.52	$10.78	$10.51
2019	$11.19	$11.19	$11.19	$11.20	$11.19	$11.46	$11.19
2020	$11.87	$11.87	$11.87	$11.88	$11.87	$12.14	$11.87
2021	$12.21	$12.21	$12.21	$12.23	$12.22	$12.48	$12.21
2022	$12.57	$12.57	$12.57	$12.58	$12.57	$12.84	$12.57
2023	$12.93	$12.93	$12.94	$12.95	$12.94	$13.21	$12.93
2024	$13.31	$13.31	$13.31	$13.32	$13.32	$13.58	$13.31
2025	$13.72	$13.72	$13.72	$13.73	$13.72	$13.99	$13.72
2026	$14.11	$14.11	$14.11	$14.12	$14.12	$14.38	$14.11
2027	$14.51	$14.51	$14.52	$14.53	$14.52	$14.79	$14.51
2028	$14.93	$14.93	$14.93	$14.94	$14.93	$15.20	$14.93
2029	$15.36	$15.36	$15.36	$15.37	$15.36	$15.63	$15.36
2030	$15.80	$15.80	$15.80	$15.81	$15.81	$16.07	$15.80
2031	$16.26	$16.25	$16.26	$16.27	$16.26	$16.53	$16.26
2032	$16.73	$16.72	$16.73	$16.74	$16.73	$17.00	$16.73
2033	$17.21	$17.21	$17.21	$17.22	$17.21	$17.48	$17.21
2034	$17.70	$17.70	$17.71	$17.72	$17.71	$17.98	$17.70
2035	$18.21	$18.21	$18.21	$18.23	$18.22	$18.49	$18.21
2036	$18.74	$18.74	$18.74	$18.76	$18.75	$19.01	$18.74
2037	$19.28	$19.28	$19.29	$19.30	$19.29	$19.56	$19.28
2038	$19.84	$19.84	$19.84	$19.85	$19.84	$20.11	$19.84
2039	$20.41	$20.41	$20.41	$20.42	$20.42	$20.68	$20.41
2040	$21.00	$21.00	$21.00	$21.01	$21.00	$21.27	$21.00
2041	$21.60	$21.60	$21.60	$21.61	$21.60	$21.87	$21.60
2042	$22.22	$22.22	$22.22	$22.23	$22.22	$22.49	$22.22
2043	$22.86	$22.86	$22.86	$22.87	$22.86	$23.13	$22.86
2044	$23.51	$23.51	$23.52	$23.53	$23.52	$23.79	$23.51
2045	$24.19	$24.19	$24.19	$24.20	$24.19	$24.46	$24.19
2046	$24.88	$24.88	$24.88	$24.89	$24.89	$25.15	$24.88
2047	$25.60	$25.59	$25.60	$25.61	$25.60	$25.87	$25.60
2048	$26.33	$26.33	$26.33	$26.34	$26.33	$26.60	$26.33
2049	$27.08	$27.08	$27.08	$27.10	$27.09	$27.35	$27.08
2050	$27.86	$27.86	$27.86	$27.87	$27.86	$28.13	$27.86
2051	$28.66	$28.66	$28.66	$28.67	$28.66	$28.93	$28.66
2052	$29.48	$29.48	$29.48	$29.49	$29.48	$29.75	$29.48
2053	$30.32	$30.32	$30.32	$30.34	$30.33	$30.59	$30.32
2054	$31.19	$31.19	$31.19	$31.20	$31.19	$31.46	$31.19

Fuel Cost Forecast 2 (Shocked Medium Price): Distillate Oil

YEAR	SHADY HILLS $/MMBTU	DESOTO $/MMBTU	OLEANDER $/MMBTU	PORT EVERGLADES $/MMBTU	LAUDERDALE $/MMBTU	FT MYERS $/MMBTU	PUTNAM $/MMBTU	MARTIN & WCEC $/MMBTU
2006	$21.95	$22.01	$22.04	$21.46	$21.46	$22.23	$22.20	$22.09
2007	$21.55	$21.66	$21.72	$20.78	$20.78	$21.55	$21.83	$21.77
2008				$21.31	$21.31	$22.08	$22.36	$22.30
2009				$19.44	$19.44	$20.22	$20.49	$20.44
2010				$19.31	$19.31	$20.08	$20.36	$20.31
2011				$17.11	$17.11	$17.88	$18.16	$18.10
2012				$18.08	$18.08	$18.86	$19.14	$19.08
2013				$18.32	$18.32	$19.10	$19.37	$19.32
2014				$18.51	$18.51	$19.29	$19.56	$19.51
2015				$19.32	$19.32	$20.10	$20.37	$20.32
2016				$20.49	$20.49	$21.26	$21.54	$21.48
2017				$17.91	$17.91	$18.55	$18.78	$18.73
2018				$14.89	$14.89	$15.39	$15.57	$15.54
2019				$15.72	$15.72	$16.22	$16.40	$16.37
2020				$16.54	$16.54	$17.04	$17.22	$17.19
2021				$16.99	$16.99	$17.49	$17.67	$17.64
2022				$17.45	$17.45	$17.96	$18.14	$18.10
2023				$17.93	$17.93	$18.43	$18.61	$18.68
2024				$18.42	$18.42	$18.93	$19.11	$19.07
2025				$18.95	$18.95	$19.45	$19.63	$19.59
2026				$19.46	$19.46	$19.96	$20.14	$20.11
2027				$19.98	$19.98	$20.49	$20.67	$20.63
2028				$20.52	$20.52	$21.03	$21.21	$21.17
2029				$21.08	$21.08	$21.59	$21.77	$21.73
2030				$21.65	$21.65	$22.16	$22.34	$22.30
2031				$22.24	$22.24	$22.75	$22.93	$22.89
2032				$22.85	$22.85	$23.35	$23.53	$23.50
2033				$23.47	$23.47	$23.98	$24.16	$24.12
2034				$24.11	$24.11	$24.62	$24.80	$24.76
2035				$24.77	$24.77	$25.27	$25.45	$25.42
2036				$25.45	$25.45	$25.95	$26.13	$26.10
2037				$26.15	$26.15	$26.65	$26.83	$26.79
2038				$26.86	$26.86	$27.36	$27.54	$27.51
2039				$27.59	$27.59	$28.10	$28.28	$28.24
2040				$28.34	$28.34	$28.85	$29.03	$28.99
2041				$29.11	$29.11	$29.62	$29.80	$29.76
2042				$29.91	$29.91	$30.41	$30.59	$30.56
2043				$30.72	$30.72	$31.23	$31.41	$31.37
2044				$31.56	$31.56	$32.06	$32.24	$32.21
2045				$32.42	$32.42	$32.92	$33.10	$33.07
2046				$33.30	$33.30	$33.81	$33.99	$33.95
2047				$34.21	$34.21	$34.71	$34.89	$34.86
2048				$35.14	$35.14	$35.65	$35.83	$35.79
2049				$36.10	$36.10	$36.60	$36.78	$36.75
2050				$37.08	$37.08	$37.59	$37.77	$37.73
2051				$38.10	$38.10	$38.60	$38.78	$38.74
2052				$39.13	$39.13	$39.64	$39.82	$39.78
2053				$40.20	$40.20	$40.70	$40.88	$40.85
2054				$41.30	$41.30	$41.80	$41.98	$41.95

Fuel Cost Forecast 3 (Medium Price): Natural Gas

YEAR	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	ZONE 3 FGT FIRM $/MMBTU	ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	GULFSTREAM FIRM - SESH PIPELINE $/MMBTU	GULFSTREAM FIRM - MOBILE BAY $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	GULFSTREAM NON-FIRM BACKHAUL $/MMBTU	UPS REPLACEMENT $/MMBTU	WILLIAMS - TRANSCO ZONE 4 $/MMBTU	PROGRESS $/MMBTU	HENRY HUB $/MMBTU
2006	$7.17	$7.26	$7.57	$7.63	$7.83		$7.49	$8.09	$8.38		$7.15	$7.11	$7.02
2007	$7.95	$8.05	$8.33	$8.41	$8.75		$8.24	$8.84	$9.23		$7.97	$8.37	$7.75
2008	$8.23	$8.33	$8.54	$8.57	$8.91	$7.80	$8.40	$9.00	$9.39		$8.23	$8.66	$8.02
2009	$7.07	$7.16	$7.37	$7.38	$7.72	$6.95	$7.23	$7.82	$8.22		$7.92	$7.45	$6.89
2010	$6.53	$6.63	$6.86	$6.87	$7.21	$6.41	$6.73	$7.32	$7.71	$6.49			$6.37
2011	$5.91	$6.00	$6.25	$6.25	$6.60	$5.80	$6.12	$6.72	$7.11	$5.93			$5.77
2012	$6.18	$6.27	$6.49	$6.49	$6.84	$6.08	$6.36	$6.96	$7.35	$6.20			$6.03
2013	$6.36	$6.45	$6.67	$6.67	$7.01	$6.24	$6.53	$7.13	$7.52	$6.37			$6.20
2014	$6.53	$6.63	$6.83	$6.83	$7.17	$6.41	$6.69	$7.29	$7.68	$6.55			$6.37
2015	$6.86	$6.96	$7.16	$7.17	$7.51	$6.74	$7.02	$7.62	$8.01	$6.87			$6.69
2016	$7.30	$7.39	$7.60	$7.60	$7.94	$7.17	$7.45	$8.05	$8.44	$7.31			$7.12
2017	$7.84	$7.94	$8.15	$8.15	$8.49	$7.71	$7.99	$8.58	$8.97	$7.85			$7.65
2018	$8.39	$8.49	$8.69	$8.70	$9.04	$8.26	$8.52	$9.12	$9.52	$8.39			$8.18
2019	$8.95	$9.04	$9.25	$9.25	$9.59	$8.80	$9.07	$9.66	$10.06	$8.94			$8.71
2020	$9.50	$9.59	$9.80	$9.80	$10.15	$9.35	$9.61	$10.21	$10.61	$9.49			$9.25
2021	$9.80	$9.89	$10.10	$10.10	$10.44	$9.65	$9.91	$10.50	$10.90				$9.54
2022	$10.11	$10.20	$10.41	$10.41	$10.75	$9.95	$10.21	$10.81	$11.20				$9.84
2023	$10.42	$10.51	$10.72	$10.72	$11.07	$10.26	$10.52	$11.12	$11.51				$10.14
2024	$10.75	$10.84	$11.05	$11.05	$11.39	$10.58	$10.84	$11.43	$11.83				$10.46
2025	$11.10	$11.20	$11.40	$11.41	$11.75	$10.94	$11.19	$11.78	$12.19				$10.81
2026	$11.44	$11.53	$11.74	$11.74	$12.09	$11.27	$11.52	$12.12	$12.52				$11.13
2027	$11.79	$11.88	$12.09	$12.09	$12.43	$11.62	$11.86	$12.46	$12.86				$11.47
2028	$12.15	$12.24	$12.45	$12.45	$12.79	$11.97	$12.22	$12.81	$13.22				$11.82
2029	$12.52	$12.61	$12.82	$12.82	$13.16	$12.34	$12.58	$13.18	$13.58				$12.18
2030	$12.90	$13.00	$13.20	$13.21	$13.55	$12.72	$12.96	$13.55	$13.96				$12.55
2031	$13.30	$13.39	$13.60	$13.60	$13.94	$13.11	$13.35	$13.94	$14.35				$12.93
2032	$13.71	$13.80	$14.01	$14.01	$14.35	$13.51	$13.75	$14.34	$14.75				$13.33
2033	$14.12	$14.22	$14.43	$14.43	$14.77	$13.93	$14.16	$14.76	$15.16				$13.74
2034	$14.56	$14.65	$14.86	$14.86	$15.20	$14.36	$14.58	$15.18	$15.59				$14.16
2035	$15.00	$15.09	$15.30	$15.30	$15.65	$14.80	$15.02	$15.62	$16.03				$14.59
2036	$15.46	$15.56	$15.76	$15.77	$16.11	$15.25	$15.47	$16.07	$16.48				$15.03
2037	$15.94	$16.03	$16.24	$16.24	$16.58	$15.72	$15.94	$16.54	$16.95				$15.49
2038	$16.42	$16.52	$16.72	$16.73	$17.07	$16.20	$16.42	$17.01	$17.43				$15.97
2039	$16.92	$17.01	$17.22	$17.22	$17.57	$16.70	$16.91	$17.51	$17.92				$16.45
2040	$17.44	$17.53	$17.74	$17.74	$18.08	$17.21	$17.41	$18.01	$18.43				$16.95
2041	$17.96	$18.06	$18.26	$18.27	$18.61	$17.73	$17.93	$18.53	$18.95				$17.46
2042	$18.51	$18.60	$18.81	$18.81	$19.15	$18.27	$18.47	$19.06	$19.48				$17.99
2043	$19.07	$19.16	$19.37	$19.37	$19.71	$18.82	$19.02	$19.61	$20.03				$18.53
2044	$19.64	$19.74	$19.94	$19.95	$20.29	$19.39	$19.58	$20.18	$20.60				$19.09
2045	$20.24	$20.33	$20.54	$20.54	$20.88	$19.98	$20.17	$20.76	$21.19				$19.66
2046	$20.84	$20.94	$21.15	$21.15	$21.49	$20.58	$20.77	$21.36	$21.79				$20.25
2047	$21.47	$21.57	$21.77	$21.78	$22.12	$21.20	$21.38	$21.98	$22.41				$20.86
2048	$22.12	$22.21	$22.42	$22.42	$22.76	$21.84	$22.02	$22.62	$23.04				$21.49
2049	$22.78	$22.88	$23.09	$23.09	$23.43	$22.50	$22.67	$23.27	$23.70				$22.14
2050	$23.47	$23.56	$23.77	$23.77	$24.12	$23.18	$23.35	$23.94	$24.37				$22.80
2051	$24.18	$24.27	$24.48	$24.48	$24.82	$23.88	$24.04	$24.64	$25.07				$23.48
2052	$24.90	$24.99	$25.20	$25.20	$25.55	$24.60	$24.75	$25.35	$25.78				$24.19
2053	$25.65	$25.74	$25.95	$25.95	$26.29	$25.34	$25.49	$26.08	$26.52				$24.91
2054	$26.42	$26.51	$26.72	$26.72	$27.06	$26.10	$26.24	$26.84	$27.28				$25.66

Fuel Cost Forecast 3 (Medium Price): Solid Fuel

YEAR	PLANT SCHERER DISPATCH PRICE WITHOUT SO2 $/MMBTU	ST. JOHNS RIVER POWER PARCK DISPATCH PRICE WITHOUT SO2 $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 $/MMBTU	FGPP DISPATCH PRICE WITHOUT SO2 $/MMBTU
2006	$2.18	$2.01	$3.59	$2.32	$3.19
2007	$2.13	$1.54	$3.22	$1.89	$2.77
2008	$1.94	$1.50	$3.07	$1.86	$2.70
2009	$1.91	$1.57	$3.07	$1.88	$2.75
2010	$1.87	$1.58	$3.05	$1.86	$2.76
2011	$1.91	$1.61	$3.09	$1.89	$2.80
2012	$1.96	$1.65	$3.14	$1.92	$2.85
2013	$2.00	$1.69	$3.18	$1.95	$2.90
2014	$2.03	$1.74	$3.22	$1.99	$2.96
2015	$2.31	$1.77	$3.27	$2.04	$3.01
2016	$2.35	$1.81	$3.35	$2.09	$3.07
2017	$2.38	$1.85	$3.44	$2.15	$3.14
2018	$2.42	$1.90	$3.53	$2.21	$3.21
2019	$2.47	$1.95	$3.63	$2.28	$3.29
2020	$2.51	$2.01	$3.73	$2.35	$3.37
2021	$2.55	$2.05	$3.82	$2.41	$3.45
2022	$2.59	$2.10	$3.92	$2.47	$3.52
2023	$2.63	$2.15	$4.01	$2.52	$3.60
2024	$2.67	$2.19	$4.11	$2.57	$3.67
2025	$2.71	$2.24	$4.28	$2.63	$3.77
2026	$2.76	$2.28	$4.38	$2.67	$3.85
2027	$2.80	$2.32	$4.49	$2.71	$3.93
2028	$2.85	$2.35	$4.61	$2.75	$4.01
2029	$2.89	$2.40	$4.73	$2.80	$4.09
2030	$2.94	$2.44	$4.85	$2.85	$4.18
2031	$2.99	$2.49	$4.98	$2.90	$4.27
2032	$3.05	$2.54	$5.11	$2.96	$4.36
2033	$3.10	$2.59	$5.24	$3.02	$4.46
2034	$3.16	$2.64	$5.39	$3.08	$4.55
2035	$3.21	$2.70	$5.53	$3.14	$4.65
2036	$3.27	$2.76	$5.67	$3.21	$4.76
2037	$3.33	$2.82	$5.82	$3.28	$4.87
2038	$3.39	$2.89	$5.98	$3.36	$4.98
2039	$3.46	$2.95	$6.14	$3.44	$5.09
2040	$3.52	$3.02	$6.31	$3.52	$5.20
2041	$3.58	$3.09	$6.47	$3.60	$5.32
2042	$3.65	$3.16	$6.65	$3.68	$5.44
2043	$3.72	$3.24	$6.83	$3.77	$5.56
2044	$3.79	$3.31	$7.02	$3.85	$5.68
2045	$3.86	$3.39	$7.21	$3.94	$5.81
2046	$3.93	$3.47	$7.40	$4.03	$5.94
2047	$4.00	$3.55	$7.61	$4.13	$6.08
2048	$4.08	$3.63	$7.82	$4.22	$6.22
2049	$4.15	$3.71	$8.04	$4.32	$6.36
2050	$4.23	$3.80	$8.27	$4.42	$6.51
2051	$4.31	$3.88	$8.50	$4.52	$6.66
2052	$4.39	$3.97	$8.74	$4.63	$6.82
2053	$4.47	$4.06	$8.98	$4.73	$6.97
2054	$4.56	$4.16	$9.24	$4.84	$7.14

Fuel Cost Forecast 3 (Medium Price): Solid Fuel

YEAR	PLANT SCHERER DISPATCH PRICE WITHOUT SO2 $/MMBTU	ST. JOHNS RIVER POWER PARCK DISPATCH PRICE WITHOUT SO2 $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 $/MMBTU	FGPP DISPATCH PRICE WITHOUT SO2 $/MMBTU
2006	$2.18	$2.01	$3.59	$2.32	$3.19
2007	$2.13	$1.54	$3.22	$1.89	$2.77
2008	$1.94	$1.50	$3.07	$1.86	$2.70
2009	$1.91	$1.57	$3.07	$1.88	$2.75
2010	$1.87	$1.58	$3.05	$1.86	$2.76
2011	$1.91	$1.61	$3.09	$1.89	$2.80
2012	$1.96	$1.65	$3.14	$1.92	$2.85
2013	$2.00	$1.69	$3.18	$1.95	$2.90
2014	$2.03	$1.74	$3.22	$1.99	$2.96
2015	$2.31	$1.77	$3.27	$2.04	$3.01
2016	$2.35	$1.81	$3.35	$2.09	$3.07
2017	$2.38	$1.85	$3.44	$2.15	$3.14
2018	$2.42	$1.90	$3.53	$2.21	$3.21
2019	$2.47	$1.95	$3.63	$2.28	$3.29
2020	$2.51	$2.01	$3.73	$2.35	$3.37
2021	$2.55	$2.05	$3.82	$2.41	$3.45
2022	$2.59	$2.10	$3.92	$2.47	$3.52
2023	$2.63	$2.15	$4.01	$2.52	$3.60
2024	$2.67	$2.19	$4.11	$2.57	$3.67
2025	$2.71	$2.24	$4.28	$2.63	$3.77
2026	$2.76	$2.28	$4.38	$2.67	$3.85
2027	$2.80	$2.32	$4.49	$2.71	$3.93
2028	$2.85	$2.35	$4.61	$2.75	$4.01
2029	$2.89	$2.40	$4.73	$2.80	$4.09
2030	$2.94	$2.44	$4.85	$2.85	$4.18
2031	$2.99	$2.49	$4.98	$2.90	$4.27
2032	$3.05	$2.54	$5.11	$2.96	$4.36
2033	$3.10	$2.59	$5.24	$3.02	$4.46
2034	$3.16	$2.64	$5.39	$3.08	$4.55
2035	$3.21	$2.70	$5.53	$3.14	$4.65
2036	$3.27	$2.76	$5.67	$3.21	$4.76
2037	$3.33	$2.82	$5.82	$3.28	$4.87
2038	$3.39	$2.89	$5.98	$3.36	$4.98
2039	$3.46	$2.95	$6.14	$3.44	$5.09
2040	$3.52	$3.02	$6.31	$3.52	$5.20
2041	$3.58	$3.09	$6.47	$3.60	$5.32
2042	$3.65	$3.16	$6.65	$3.68	$5.44
2043	$3.72	$3.24	$6.83	$3.77	$5.56
2044	$3.79	$3.31	$7.02	$3.85	$5.68
2045	$3.86	$3.39	$7.21	$3.94	$5.81
2046	$3.93	$3.47	$7.40	$4.03	$5.94
2047	$4.00	$3.55	$7.61	$4.13	$6.08
2048	$4.08	$3.63	$7.82	$4.22	$6.22
2049	$4.15	$3.71	$8.04	$4.32	$6.36
2050	$4.23	$3.80	$8.27	$4.42	$6.51
2051	$4.31	$3.88	$8.50	$4.52	$6.66
2052	$4.39	$3.97	$8.74	$4.63	$6.82
2053	$4.47	$4.06	$8.98	$4.73	$6.97
2054	$4.56	$4.16	$9.24	$4.84	$7.14

Fuel Cost Forecast 3 (Medium Price): Residual Fuel Oil

YEAR	MARTIN 1% $/MMBTU	PORT EVERGLADES 1% $/MMBTU	MANATEE 1% $/MMBTU	TURKEY POINT 1% $/MMBTU	INDIAN RIVER & CANAVERAL 1% $/MMBTU	SANFORD 1% $/MMBTU	RIVIERA 1% $/MMBTU
2006	$7.93	$7.89	$7.90	$7.91	$7.88	$8.26	$7.88
2007	$7.54	$7.54	$7.54	$7.56	$7.55	$7.81	$7.54
2008	$8.66	$8.66	$8.66	$8.67	$8.66	$8.93	$8.66
2009	$8.22	$8.22	$8.22	$8.23	$8.22	$8.49	$8.22
2010	$8.13	$8.13	$8.13	$8.14	$8.13	$8.40	$8.13
2011	$7.91	$7.91	$7.91	$7.92	$7.91	$8.18	$7.91
2012	$8.36	$8.36	$8.36	$8.37	$8.36	$8.63	$8.36
2013	$8.30	$8.30	$8.30	$8.31	$8.31	$8.57	$8.30
2014	$8.24	$8.24	$8.25	$8.26	$8.25	$8.52	$8.24
2015	$8.59	$8.59	$8.59	$8.61	$8.60	$8.86	$8.59
2016	$9.22	$9.22	$9.22	$9.23	$9.23	$9.49	$9.22
2017	$9.85	$9.85	$9.86	$9.87	$9.86	$10.13	$9.85
2018	$10.51	$10.51	$10.51	$10.53	$10.52	$10.78	$10.51
2019	$11.19	$11.19	$11.19	$11.20	$11.19	$11.46	$11.19
2020	$11.87	$11.87	$11.87	$11.88	$11.87	$12.14	$11.87
2021	$12.21	$12.21	$12.21	$12.23	$12.22	$12.48	$12.21
2022	$12.57	$12.57	$12.57	$12.58	$12.57	$12.84	$12.57
2023	$12.93	$12.93	$12.94	$12.95	$12.94	$13.21	$12.93
2024	$13.31	$13.31	$13.31	$13.32	$13.32	$13.58	$13.31
2025	$13.72	$13.72	$13.72	$13.73	$13.72	$13.99	$13.72
2026	$14.11	$14.11	$14.11	$14.12	$14.12	$14.38	$14.11
2027	$14.51	$14.51	$14.52	$14.53	$14.52	$14.79	$14.51
2028	$14.93	$14.93	$14.93	$14.94	$14.93	$15.20	$14.93
2029	$15.36	$15.36	$15.36	$15.37	$15.36	$15.63	$15.36
2030	$15.80	$15.80	$15.80	$15.81	$15.81	$16.07	$15.80
2031	$16.26	$16.25	$16.26	$16.27	$16.26	$16.53	$16.26
2032	$16.73	$16.72	$16.73	$16.74	$16.73	$17.00	$16.73
2033	$17.21	$17.21	$17.21	$17.22	$17.21	$17.48	$17.21
2034	$17.70	$17.70	$17.71	$17.72	$17.71	$17.98	$17.70
2035	$18.21	$18.21	$18.21	$18.23	$18.22	$18.49	$18.21
2036	$18.74	$18.74	$18.74	$18.76	$18.75	$19.01	$18.74
2037	$19.28	$19.28	$19.29	$19.30	$19.29	$19.56	$19.28
2038	$19.84	$19.84	$19.84	$19.85	$19.84	$20.11	$19.84
2039	$20.41	$20.41	$20.41	$20.42	$20.42	$20.68	$20.41
2040	$21.00	$21.00	$21.00	$21.01	$21.00	$21.27	$21.00
2041	$21.60	$21.60	$21.60	$21.61	$21.60	$21.87	$21.60
2042	$22.22	$22.22	$22.22	$22.23	$22.22	$22.49	$22.22
2043	$22.86	$22.86	$22.86	$22.87	$22.86	$23.13	$22.86
2044	$23.51	$23.51	$23.52	$23.53	$23.52	$23.79	$23.51
2045	$24.19	$24.19	$24.19	$24.20	$24.19	$24.46	$24.19
2046	$24.88	$24.88	$24.88	$24.89	$24.89	$25.15	$24.88
2047	$25.60	$25.59	$25.60	$25.61	$25.60	$25.87	$25.60
2048	$26.33	$26.33	$26.33	$26.34	$26.33	$26.60	$26.33
2049	$27.08	$27.08	$27.08	$27.10	$27.09	$27.35	$27.08
2050	$27.86	$27.86	$27.86	$27.87	$27.86	$28.13	$27.86
2051	$28.66	$28.66	$28.66	$28.67	$28.66	$28.93	$28.66
2052	$29.48	$29.48	$29.48	$29.49	$29.48	$29.75	$29.48
2053	$30.32	$30.32	$30.32	$30.34	$30.33	$30.59	$30.32
2054	$31.19	$31.19	$31.19	$31.20	$31.19	$31.46	$31.19

Fuel Cost Forecast 3 (Medium Price): Distillate Oil

YEAR	SHADY HILLS $/MMBTU	DESOTO $/MMBTU	OLEANDER $/MMBTU	PORT EVERGLADES $/MMBTU	LAUDERDALE $/MMBTU	FT MYERS $/MMBTU	PUTNAM $/MMBTU	MARTIN & WCEC $/MMBTU
2006	$14.26	$14.29	$14.31	$13.93	$13.93	$14.44	$14.42	$14.35
2007	$14.00	$14.07	$14.10	$13.49	$13.49	$14.00	$14.18	$14.14
2008				$13.84	$13.84	$14.34	$14.52	$14.48
2009				$12.62	$12.62	$13.13	$13.31	$13.27
2010				$12.54	$12.54	$13.04	$13.22	$13.19
2011				$11.11	$11.11	$11.61	$11.79	$11.76
2012				$11.74	$11.74	$12.26	$12.43	$12.39
2013				$11.90	$11.90	$12.40	$12.58	$12.54
2014				$12.02	$12.02	$12.52	$12.70	$12.67
2015				$12.55	$12.55	$13.05	$13.23	$13.19
2016				$13.30	$13.30	$13.81	$13.99	$13.95
2017				$14.10	$14.10	$14.60	$14.78	$14.75
2018				$14.89	$14.89	$15.39	$15.57	$15.54
2019				$15.72	$15.72	$16.22	$16.40	$16.37
2020				$16.54	$16.54	$17.04	$17.22	$17.19
2021				$16.99	$16.99	$17.49	$17.67	$17.64
2022				$17.45	$17.45	$17.96	$18.14	$18.10
2023				$17.93	$17.93	$18.43	$18.61	$18.58
2024				$18.42	$18.42	$18.93	$19.11	$19.07
2025				$18.95	$18.95	$19.45	$19.63	$19.59
2026				$19.46	$19.46	$19.96	$20.14	$20.11
2027				$19.98	$19.98	$20.49	$20.67	$20.63
2028				$20.52	$20.62	$21.03	$21.21	$21.17
2029				$21.08	$21.08	$21.59	$21.77	$21.73
2030				$21.65	$21.65	$22.16	$22.34	$22.30
2031				$22.24	$22.24	$22.75	$22.93	$22.89
2032				$22.85	$22.85	$23.35	$23.53	$23.50
2033				$23.47	$23.47	$23.98	$24.16	$24.12
2034				$24.11	$24.11	$24.62	$24.80	$24.76
2035				$24.77	$24.77	$25.27	$25.45	$25.42
2036				$25.45	$25.45	$25.95	$26.13	$26.10
2037				$26.15	$26.15	$26.65	$26.83	$26.79
2038				$26.86	$26.86	$27.36	$27.54	$27.51
2039				$27.59	$27.59	$28.10	$28.28	$28.24
2040				$28.34	$28.34	$28.85	$29.03	$28.99
2041				$29.11	$29.11	$29.62	$29.80	$29.76
2042				$29.91	$29.91	$30.41	$30.59	$30.56
2043				$30.72	$30.72	$31.23	$31.41	$31.37
2044				$31.56	$31.56	$32.06	$32.24	$32.21
2045				$32.42	$32.42	$32.92	$33.10	$33.07
2046				$33.30	$33.30	$33.81	$33.99	$33.95
2047				$34.21	$34.21	$34.71	$34.89	$34.86
2048				$35.14	$35.14	$35.65	$35.83	$35.79
2049				$36.10	$36.10	$36.60	$36.78	$36.75
2050				$37.08	$37.08	$37.59	$37.77	$37.73
2051				$38.10	$38.10	$38.60	$38.78	$38.74
2052				$39.13	$39.13	$39.64	$39.82	$39.78
2053				$40.20	$40.20	$40.70	$40.88	$40.85
2054				$41.30	$41.30	$41.80	$41.98	$41.95

Fuel Cost Forecast 4 (Low Price): Natural Gas

YEAR	ZONE 1 FGT FIRM $/MMBTU	ZONE 2 FGT FIRM $/MMBTU	ZONE 3 FGT FIRM $/MMBTU	ZONE 3 MOBILE BAY/DESTIN FGT FIRM $/MMBTU	FGT NON-FIRM $/MMBTU	GULFSTREAM FIRM - SESH PIPELINE $/MMBTU	GULFSTREAM FIRM - MOBILE BAY $/MMBTU	GULFSTREAM NON-FIRM $/MMBTU	GULFSTREAM NON-FIRM BACKHAUL $/MMBTU	UPS REPLACEMENT $/MMBTU	WILLIAMS - TRANSCO ZONE 4 $/MMBTU	PROGRESS $/MMBTU	HENRY HUB $/MMBTU
2006	$4.67	$4.73	$4.93	$4.98	$5.11		$4.88	$5.27	$5.47		$4.66	$4.64	$4.58
2007	$5.19	$5.25	$5.43	$5.48	$5.71		$5.38	$5.77	$6.02		$5.20	$5.46	$5.06
2008	$5.37	$5.43	$5.57	$5.59	$5.81	$5.09	$5.48	$5.87	$6.12		$5.37	$5.65	$5.23
2009	$4.61	$4.67	$4.81	$4.81	$5.03	$4.53	$4.71	$5.10	$5.36		$5.16	$4.86	$4.50
2010	$4.26	$4.32	$4.48	$4.48	$4.70	$4.18	$4.39	$4.78	$5.03	$4.23			$4.16
2011	$3.86	$3.92	$4.08	$4.08	$4.30	$3.78	$3.99	$4.38	$4.64	$3.87			$3.76
2012	$4.03	$4.09	$4.23	$4.24	$4.46	$3.95	$4.15	$4.54	$4.79	$4.04			$3.93
2013	$4.15	$4.21	$4.35	$4.35	$4.57	$4.07	$4.26	$4.65	$4.90	$4.16			$4.05
2014	$4.26	$4.32	$4.45	$4.45	$4.68	$4.18	$4.36	$4.75	$5.01	$4.27			$4.16
2015	$4.48	$4.54	$4.67	$4.67	$4.90	$4.40	$4.58	$4.97	$5.22	$4.48			$4.37
2016	$4.76	$4.82	$4.96	$4.96	$5.18	$4.68	$4.86	$5.25	$5.50	$4.77			$4.64
2017	$5.12	$5.18	$5.31	$5.31	$5.54	$5.03	$5.21	$5.60	$5.85	$5.12			$4.99
2018	$5.47	$5.53	$5.67	$5.67	$5.89	$5.38	$5.56	$5.95	$6.21	$5.48			$5.33
2019	$5.83	$5.90	$6.03	$6.03	$6.26	$5.74	$5.91	$6.30	$6.56	$5.83			$5.68
2020	$6.20	$6.26	$6.39	$6.39	$6.62	$6.10	$6.27	$6.66	$6.92	$6.19			$6.03
2021	$6.39	$6.45	$6.59	$6.59	$6.81	$6.29	$6.46	$6.85	$7.11				$6.22
2022	$6.59	$6.65	$6.79	$6.79	$7.01	$6.49	$6.66	$7.05	$7.31				$6.42
2023	$6.80	$6.86	$6.99	$6.99	$7.22	$6.69	$6.86	$7.25	$7.51				$6.62
2024	$7.01	$7.07	$7.21	$7.21	$7.43	$6.90	$7.07	$7.46	$7.72				$6.82
2025	$7.24	$7.30	$7.44	$7.44	$7.66	$7.13	$7.30	$7.69	$7.95				$7.05
2026	$7.46	$7.52	$7.66	$7.66	$7.88	$7.35	$7.51	$7.90	$8.17				$7.26
2027	$7.69	$7.75	$7.89	$7.89	$8.11	$7.58	$7.74	$8.13	$8.39				$7.48
2028	$7.92	$7.98	$8.12	$8.12	$8.34	$7.81	$7.97	$8.36	$8.62				$7.71
2029	$8.17	$8.23	$8.36	$8.36	$8.59	$8.05	$8.21	$8.59	$8.86				$7.94
2030	$8.42	$8.48	$8.61	$8.61	$8.84	$8.30	$8.45	$8.84	$9.10				$8.19
2031	$8.67	$8.73	$8.87	$8.87	$9.09	$8.55	$8.70	$9.09	$9.36				$8.44
2032	$8.94	$9.00	$9.14	$9.14	$9.36	$8.81	$8.97	$9.36	$9.62				$8.69
2033	$9.21	$9.27	$9.41	$9.41	$9.63	$9.08	$9.23	$9.62	$9.89				$8.96
2034	$9.49	$9.56	$9.69	$9.69	$9.91	$9.36	$9.51	$9.90	$10.17				$9.23
2035	$9.78	$9.84	$9.98	$9.98	$10.20	$9.65	$9.80	$10.19	$10.45				$9.51
2036	$10.09	$10.15	$10.28	$10.28	$10.51	$9.95	$10.09	$10.48	$10.75				$9.81
2037	$10.39	$10.46	$10.59	$10.59	$10.81	$10.26	$10.40	$10.79	$11.06				$10.11
2038	$10.71	$10.77	$10.91	$10.91	$11.13	$10.57	$10.71	$11.10	$11.37				$10.41
2039	$11.04	$11.10	$11.23	$11.23	$11.46	$10.89	$11.03	$11.42	$11.69				$10.73
2040	$11.37	$11.43	$11.57	$11.57	$11.79	$11.22	$11.36	$11.75	$12.02				$11.05
2041	$11.72	$11.78	$11.91	$11.91	$12.14	$11.56	$11.70	$12.09	$12.36				$11.39
2042	$12.07	$12.13	$12.27	$12.27	$12.49	$11.91	$12.04	$12.43	$12.71				$11.73
2043	$12.44	$12.50	$12.63	$12.63	$12.86	$12.28	$12.40	$12.79	$13.07				$12.09
2044	$12.81	$12.87	$13.01	$13.01	$13.23	$12.65	$12.77	$13.16	$13.44				$12.45
2045	$13.20	$13.26	$13.39	$13.40	$13.62	$13.03	$13.15	$13.54	$13.82				$12.82
2046	$13.60	$13.66	$13.79	$13.79	$14.02	$13.42	$13.54	$13.93	$14.21				$13.21
2047	$14.01	$14.07	$14.20	$14.20	$14.43	$13.83	$13.95	$14.34	$14.61				$13.61
2048	$14.43	$14.49	$14.62	$14.62	$14.85	$14.25	$14.36	$14.75	$15.03				$14.02
2049	$14.86	$14.92	$15.06	$15.06	$15.28	$14.68	$14.79	$15.18	$15.46				$14.44
2050	$15.31	$15.37	$15.50	$15.51	$15.73	$15.12	$15.23	$15.62	$15.90				$14.87
2051	$15.77	$15.83	$15.96	$15.96	$16.19	$15.57	$15.68	$16.07	$16.35				$15.32
2052	$16.24	$16.30	$16.44	$16.44	$16.66	$16.04	$16.14	$16.53	$16.82				$15.78
2053	$16.73	$16.79	$16.92	$16.92	$17.15	$16.52	$16.62	$17.01	$17.30				$16.25
2054	$17.23	$17.29	$17.42	$17.43	$17.65	$17.02	$17.12	$17.50	$17.79				$16.73

Fuel Cost Forecast 4 (Low Price): Solid Fuel

YEAR	PLANT SCHERER DISPATCH PRICE WITHOUT SO2 $/MMBTU	ST. JOHNS RIVER POWER PARCK DISPATCH PRICE WITHOUT SO2 $/MMBTU	ICL DISPATCH PRICE WITHOUT SO2 $/MMBTU	CEDAR BAY DISPATCH PRICE WITHOUT SO2 $/MMBTU	FGPP DISPATCH PRICE WITHOUT SO2 $/MMBTU
2006	$1.98	$1.83	$3.26	$2.12	$2.91
2007	$1.94	$1.40	$2.93	$1.72	$2.52
2008	$1.76	$1.37	$2.80	$1.69	$2.46
2009	$1.74	$1.43	$2.79	$1.72	$2.50
2010	$1.70	$1.43	$2.78	$1.70	$2.51
2011	$1.74	$1.46	$2.81	$1.72	$2.55
2012	$1.78	$1.50	$2.86	$1.74	$2.60
2013	$1.82	$1.54	$2.90	$1.77	$2.64
2014	$1.85	$1.58	$2.93	$1.81	$2.69
2015	$2.11	$1.61	$2.98	$1.86	$2.74
2016	$2.14	$1.65	$3.05	$1.90	$2.80
2017	$2.17	$1.69	$3.13	$1.95	$2.86
2018	$2.21	$1.73	$3.21	$2.01	$2.92
2019	$2.24	$1.78	$3.30	$2.07	$2.99
2020	$2.28	$1.83	$3.40	$2.14	$3.07
2021	$2.32	$1.87	$3.48	$2.19	$3.14
2022	$2.36	$1.91	$3.57	$2.25	$3.20
2023	$2.39	$1.96	$3.65	$2.29	$3.27
2024	$2.43	$2.00	$3.74	$2.34	$3.34
2025	$2.47	$2.04	$3.89	$2.39	$3.43
2026	$2.51	$2.07	$3.99	$2.43	$3.50
2027	$2.55	$2.11	$4.09	$2.47	$3.57
2028	$2.59	$2.14	$4.19	$2.50	$3.65
2029	$2.63	$2.18	$4.30	$2.55	$3.72
2030	$2.68	$2.22	$4.41	$2.59	$3.80
2031	$2.72	$2.27	$4.53	$2.64	$3.88
2032	$2.77	$2.31	$4.65	$2.69	$3.97
2033	$2.82	$2.36	$4.77	$2.75	$4.06
2034	$2.87	$2.41	$4.90	$2.80	$4.14
2035	$2.93	$2.45	$5.03	$2.85	$4.24
2036	$2.98	$2.51	$5.16	$2.92	$4.33
2037	$3.03	$2.57	$5.30	$2.99	$4.43
2038	$3.09	$2.63	$5.44	$3.06	$4.53
2039	$3.15	$2.69	$5.59	$3.13	$4.63
2040	$3.20	$2.75	$5.74	$3.20	$4.73
2041	$3.26	$2.81	$5.89	$3.27	$4.84
2042	$3.32	$2.88	$6.05	$3.35	$4.95
2043	$3.38	$2.95	$6.22	$3.43	$5.06
2044	$3.45	$3.01	$6.39	$3.51	$5.17
2045	$3.51	$3.08	$6.56	$3.59	$5.29
2046	$3.58	$3.15	$6.74	$3.67	$5.41
2047	$3.64	$3.23	$6.93	$3.76	$5.53
2048	$3.71	$3.30	$7.12	$3.84	$5.66
2049	$3.78	$3.38	$7.32	$3.93	$5.79
2050	$3.85	$3.46	$7.52	$4.02	$5.93
2051	$3.92	$3.53	$7.73	$4.12	$6.06
2052	$3.99	$3.62	$7.95	$4.21	$6.20
2053	$4.07	$3.70	$8.17	$4.31	$6.35
2054	$4.15	$3.79	$8.41	$4.41	$6.50

Fuel Cost Forecast 4 (Low Price): Residual Fuel Oil

YEAR	MARTIN 1% $/MMBTU	PORT EVERGLADES 1% $/MMBTU	MANATEE 1% $/MMBTU	TURKEY POINT 1% $/MMBTU	INDIAN RIVER & CANAVERAL 1% $/MMBTU	SANFORD 1% $/MMBTU	RIVIERA 1% $/MMBTU
2006	$6.44	$6.41	$6.42	$6.43	$6.41	$6.71	$6.40
2007	$6.13	$6.13	$6.13	$6.14	$6.13	$6.35	$6.13
2008	$7.04	$7.03	$7.04	$7.05	$7.04	$7.26	$7.04
2009	$6.68	$6.68	$6.68	$6.69	$6.68	$6.90	$6.68
2010	$6.61	$6.60	$6.61	$6.62	$6.61	$6.83	$6.61
2011	$6.43	$6.42	$6.43	$6.44	$6.43	$6.65	$6.43
2012	$6.79	$6.79	$6.79	$6.80	$6.80	$7.01	$6.79
2013	$6.75	$6.74	$6.75	$6.76	$6.75	$6.97	$6.75
2014	$6.70	$6.70	$6.70	$6.71	$6.70	$6.92	$6.70
2015	$6.98	$6.98	$6.98	$6.99	$6.99	$7.20	$6.98
2016	$7.49	$7.49	$7.49	$7.50	$7.50	$7.71	$7.49
2017	$8.01	$8.01	$8.01	$8.02	$8.01	$8.23	$8.01
2018	$8.54	$8.54	$8.54	$8.55	$8.55	$8.76	$8.54
2019	$9.09	$9.09	$9.09	$9.10	$9.10	$9.31	$9.09
2020	$9.64	$9.64	$9.64	$9.65	$9.65	$9.86	$9.64
2021	$9.92	$9.92	$9.93	$9.93	$9.93	$10.14	$9.92
2022	$10.21	$10.21	$10.22	$10.22	$10.22	$10.43	$10.21
2023	$10.51	$10.51	$10.51	$10.52	$10.51	$10.73	$10.51
2024	$10.82	$10.82	$10.82	$10.83	$10.82	$11.04	$10.82
2025	$11.15	$11.15	$11.15	$11.16	$11.15	$11.37	$11.15
2026	$11.47	$11.47	$11.47	$11.48	$11.47	$11.69	$11.47
2027	$11.80	$11.79	$11.80	$11.81	$11.80	$12.02	$11.80
2028	$12.13	$12.13	$12.13	$12.14	$12.14	$12.35	$12.13
2029	$12.48	$12.48	$12.48	$12.49	$12.48	$12.70	$12.48
2030	$12.84	$12.84	$12.84	$12.85	$12.84	$13.06	$12.84
2031	$13.21	$13.21	$13.21	$13.22	$13.21	$13.43	$13.21
2032	$13.59	$13.59	$13.59	$13.60	$13.60	$13.81	$13.59
2033	$13.98	$13.98	$13.98	$13.99	$13.99	$14.20	$13.98
2034	$14.39	$14.39	$14.39	$14.40	$14.39	$14.61	$14.39
2035	$14.80	$14.80	$14.80	$14.81	$14.80	$15.02	$14.80
2036	$15.23	$15.23	$15.23	$15.24	$15.23	$15.45	$15.23
2037	$15.67	$15.67	$15.67	$15.68	$15.67	$15.89	$15.67
2038	$16.12	$16.12	$16.12	$16.13	$16.13	$16.34	$16.12
2039	$16.59	$16.59	$16.59	$16.60	$16.59	$16.81	$16.59
2040	$17.06	$17.06	$17.06	$17.07	$17.07	$17.28	$17.06
2041	$17.55	$17.55	$17.55	$17.56	$17.56	$17.77	$17.55
2042	$18.06	$18.06	$18.06	$18.07	$18.06	$18.28	$18.06
2043	$18.58	$18.57	$18.58	$18.59	$18.58	$18.80	$18.58
2044	$19.11	$19.11	$19.11	$19.12	$19.11	$19.33	$19.11
2045	$19.66	$19.66	$19.66	$19.67	$19.66	$19.88	$19.66
2046	$20.22	$20.22	$20.22	$20.23	$20.22	$20.44	$20.22
2047	$20.80	$20.80	$20.80	$20.81	$20.80	$21.02	$20.80
2048	$21.40	$21.39	$21.40	$21.41	$21.40	$21.62	$21.40
2049	$22.01	$22.01	$22.01	$22.02	$22.01	$22.23	$22.01
2050	$22.64	$22.64	$22.64	$22.65	$22.64	$22.86	$22.64
2051	$23.29	$23.29	$23.29	$23.30	$23.29	$23.51	$23.29
2052	$23.96	$23.95	$23.96	$23.97	$23.96	$24.18	$23.96
2053	$24.64	$24.64	$24.64	$24.65	$24.64	$24.86	$24.64
2054	$25.35	$25.35	$25.35	$25.36	$25.35	$25.57	$25.35

Fuel Cost Forecast 4 (Low Price): Distillate Oil

YEAR	SHADY HILLS $/MMBTU	DESOTO $/MMBTU	OLEANDER $/MMBTU	PORT EVERGLADES $/MMBTU	LAUDERDALE $/MMBTU	FT MYERS $/MMBTU	PUTNAM $/MMBTU	MARTIN & WCEC $/MMBTU
2006	$11.59	$11.61	$11.63	$11.32	$11.32	$11.73	$11.72	$11.66
2007	$11.37	$11.43	$11.46	$10.96	$10.96	$11.37	$11.52	$11.49
2008				$11.24	$11.24	$11.65	$11.80	$11.77
2009				$10.26	$10.26	$10.67	$10.81	$10.79
2010				$10.19	$10.19	$10.60	$10.74	$10.72
2011				$9.03	$9.03	$9.44	$9.58	$9.55
2012				$9.54	$9.54	$9.95	$10.10	$10.07
2013				$9.67	$9.67	$10.08	$10.22	$10.19
2014				$9.77	$9.77	$10.18	$10.32	$10.29
2015				$10.19	$10.19	$10.60	$10.75	$10.72
2016				$10.81	$10.81	$11.22	$11.37	$11.34
2017				$11.46	$11.46	$11.87	$12.01	$11.98
2018				$12.10	$12.10	$12.51	$12.66	$12.63
2019				$12.77	$12.77	$13.18	$13.33	$13.30
2020				$13.44	$13.44	$13.85	$13.99	$13.97
2021				$13.81	$13.81	$14.22	$14.36	$14.33
2022				$14.18	$14.18	$14.59	$14.74	$14.71
2023				$14.57	$14.57	$14.98	$15.13	$15.10
2024				$14.97	$14.97	$15.38	$15.53	$15.50
2025				$15.40	$15.40	$15.81	$15.95	$15.92
2026				$15.81	$15.81	$16.22	$16.37	$16.34
2027				$16.24	$16.24	$16.65	$16.80	$16.77
2028				$16.68	$16.68	$17.09	$17.23	$17.21
2029				$17.13	$17.13	$17.54	$17.69	$17.66
2030				$17.60	$17.60	$18.01	$18.15	$18.12
2031				$18.08	$18.08	$18.49	$18.63	$18.60
2032				$18.57	$18.57	$18.98	$19.13	$19.10
2033				$19.07	$19.07	$19.48	$19.63	$19.60
2034				$19.60	$19.60	$20.01	$20.15	$20.12
2035				$20.13	$20.13	$20.54	$20.68	$20.66
2036				$20.68	$20.68	$21.09	$21.24	$21.21
2037				$21.25	$21.25	$21.66	$21.80	$21.77
2038				$21.83	$21.83	$22.24	$22.38	$22.35
2039				$22.42	$22.42	$22.83	$22.98	$22.95
2040				$23.03	$23.03	$23.44	$23.59	$23.56
2041				$23.66	$23.66	$24.07	$24.22	$24.19
2042				$24.30	$24.30	$24.71	$24.86	$24.83
2043				$24.97	$24.97	$25.38	$25.52	$25.49
2044				$25.65	$25.65	$26.06	$26.20	$26.17
2045				$26.35	$26.35	$26.76	$26.90	$26.87
2046				$27.06	$27.06	$27.47	$27.62	$27.59
2047				$27.80	$27.80	$28.21	$28.36	$28.33
2048				$28.56	$28.56	$28.97	$29.11	$29.08
2049				$29.34	$29.34	$29.75	$29.89	$29.86
2050				$30.14	$30.14	$30.55	$30.69	$30.66
2051				$30.96	$30.96	$31.37	$31.51	$31.48
2052				$31.80	$31.80	$32.21	$32.36	$32.33
2053				$32.67	$32.67	$33.08	$33.22	$33.19
2054				$33.56	$33.56	$33.97	$34.12	$34.09

All Fuel Cost Forecasts: Natural Gas Transportation Demand Charge

YEAR	FGT MILLIONS $	GULSTREAM MILLIONS $	SESH MILLIONS $	UPS REPLACEMENT MILLIONS $	PLAN WITH COAL MILLIONS $	PLAN WITHOUT COAL (FPL & OTHERS) MILLIONS $	SINGLE FILLER UNIT MILLIONS $
2006	$187.7	$70.6					
2007	$186.2	$88.0					
2008	$184.4	$89.9	$29.4				
2009	$183.9	$128.3	$50.2				
2010	$183.9	$142.0	$50.2	$8.1			
2011	$298.8	$142.0	$50.2	$13.9			
2012	$382.1	$142.4	$50.3	$13.9		$32.1	
2013	$381.1	$142.0	$44.7	$13.9		$54.8	
2014	$396.4	$142.0	$40.9	$13.9		$91.5	
2015	$407.2	$142.0	$40.9	$13.9	$32.1	$117.3	
2016	$408.3	$142.4	$41.0	$13.9	$54.9	$159.2	
2017	$407.2	$142.0	$40.9	$13.9	$54.8	$188.2	$30.9
2018	$407.2	$142.0	$40.9	$13.9	$54.8	$188.2	$52.7
2019	$422.6	$142.0	$40.9	$13.9	$54.8	$188.2	$52.7
2020	$434.6	$142.4	$41.0	$13.9	$54.9	$188.8	$52.7
2021	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2022	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2023	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2024	$434.6	$142.4	$41.0		$54.9	$188.8	$52.7
2025	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2026	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2027	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2028	$434.6	$142.4	$41.0		$54.9	$188.8	$52.7
2029	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2030	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2031	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2032	$434.6	$142.4	$41.0		$54.9	$188.8	$52.7
2033	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2034	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2035	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2036	$434.6	$142.4	$41.0		$54.9	$188.8	$52.7
2037	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2038	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2039	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2040	$434.6	$142.4	$41.0		$54.9	$188.8	$52.7
2041	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2042	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2043	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2044	$434.6	$142.4	$41.0		$54.9	$188.8	$52.7
2045	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2046	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2047	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2048	$434.6	$142.4	$41.0		$54.9	$188.8	$52.7
2049	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2050	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2051	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2052	$434.6	$142.4	$41.0		$54.9	$188.8	$52.7
2053	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7
2054	$433.4	$142.0	$40.9		$54.8	$188.2	$52.7

All Fuel Cost Forecasts: Natural Gas Availability

YEAR	ZONE 1 FGT FIRM MMCF/DAY	ZONE 2 FGT FIRM MMCF/DAY	ZONE 3 FGT FIRM MMCF/DAY	ZONE 3 MOBILE BAY/DESTIN FGT FIRM MMCF/DAY	FGT NON-FIRM MMCF/DAY	GULFSTREAM FIRM - SESH PIPELINE MMCF/DAY	GULFSTREAM FIRM - MOBILE BAY MMCF/DAY	GULFSTREAM NON-FIRM AND NON-FIRM BACKHAUL MMCF/DAY	PLAN WITH COAL: INCRMENTAL GULFSTREAM VOLUME MMCF/DAY	PLAN WITHOUT COAL: INCREMENTAL GULFSTREAM VOLUME (FPL & OTHERS) MMCF/DAY	PLAN WITHOUT COAL: INCREMENTAL FGT VOLUME (FPL & OTHERS) MMCF/DAY	SINGLE FILLER UNIT MMCF/DAY
2006	163	289	109	272	132		350	375				
2007	163	289	109	272	143		423	368				
2008	155	281	109	259	108	292	163	244				
2009	155	281	109	272	98	500	128	121				
2010	155	281	109	272	98	500	195	98				
2011	155	281	109	272	98	500	195	98				
2012	155	281	109	272	98	500	195	98		200		
2013	155	281	109	272	98	442	253	98		200		
2014	155	281	109	272	98	400	295	98		302		
2015	155	281	109	272	98	400	295	98	200	375		
2016	155	281	109	272	98	400	295	98	200	375	175	
2017	155	281	109	272	98	400	295	98	200	375	175	87.5
2018	155	281	109	272	98	400	295	98	200	375	175	87.5
2019	155	281	109	272	98	400	295	98	200	375	175	87.5
2020	155	281	109	272	98	400	295	98	200	375	175	87.5
2021	155	281	109	272	98	400	295	98	200	375	175	87.5
2022	155	281	109	272	98	400	295	98	200	375	175	87.5
2023	155	281	109	272	98	400	295	98	200	375	175	87.5
2024	155	281	109	272	98	400	295	98	200	375	175	87.5
2025	155	281	109	272	98	400	295	98	200	375	175	87.5
2026	155	281	109	272	98	400	295	98	200	375	175	87.5
2027	155	281	109	272	98	400	295	98	200	375	175	87.5
2028	155	281	109	272	98	400	295	98	200	375	175	87.5
2029	155	281	109	272	98	400	295	98	200	375	175	87.5
2030	155	281	109	272	98	400	295	98	200	375	175	87.5
2031	155	281	109	272	98	400	295	98	200	375	175	87.5
2032	155	281	109	272	98	400	295	98	200	375	175	87.5
2033	155	281	109	272	98	400	295	98	200	375	175	87.5
2034	155	281	109	272	98	400	295	98	200	375	175	87.5
2035	155	281	109	272	98	400	295	98	200	375	175	87.5
2036	155	281	109	272	98	400	295	98	200	375	175	87.5
2037	155	281	109	272	98	400	295	98	200	375	175	87.5
2038	155	281	109	272	98	400	295	98	200	375	175	87.5
2039	155	281	109	272	98	400	295	98	200	375	175	87.5
2040	155	281	109	272	98	400	295	98	200	375	175	87.5
2041	155	281	109	272	98	400	295	98	200	375	175	87.5
2042	155	281	109	272	98	400	295	98	200	375	175	87.5
2043	155	281	109	272	98	400	295	98	200	375	175	87.5
2044	155	281	109	272	98	400	295	98	200	375	175	87.5
2045	155	281	109	272	98	400	295	98	200	375	175	87.5
2046	155	281	109	272	98	400	295	98	200	375	175	87.5
2047	155	281	109	272	98	400	295	98	200	375	175	87.5
2048	155	281	109	272	98	400	295	98	200	375	175	87.5
2049	155	281	109	272	98	400	295	98	200	375	175	87.5
2050	155	281	109	272	98	400	295	98	200	375	175	87.5
2051	155	281	109	272	98	400	295	98	200	375	175	87.5
2052	155	281	109	272	98	400	295	98	200	375	175	87.5
2053	155	281	109	272	98	400	295	98	200	375	175	87.5
2054	155	281	109	272	98	400	295	98	200	375	175	87.5

Natural Gas - Solid Fuel Differential

YEAR	FUEL PRICE FORECAST 1 (HIGH PRICE) $/MMBTU	FUEL PRICE FORECAST 2: (SHOCKED MEDIUM PRICE) $/MMBTU	FUEL PRICE FORECAST 3: (MEDIUM PRICE) $/MMBTU	FUEL PRICE FORECAST 4: (LOW PRICE) $/MMBTU
2006	$7.07	$10.59	$4.30	$1.98
2007	$8.66	$12.39	$5.47	$2.85
2008	$8.97	$12.75	$5.70	$3.02
2009	$7.21	$10.55	$4.48	$2.21
2010	$6.48	$9.62	$3.97	$1.88
2011	$5.56	$8.47	$3.33	$1.45
2012	$5.83	$8.85	$3.51	$1.55
2013	$6.02	$9.11	$3.63	$1.62
2014	$6.19	$9.35	$3.73	$1.67
2015	$6.60	$9.91	$4.01	$1.84
2016	$7.15	$10.64	$4.38	$2.06
2017	$7.85	$8.20	$4.85	$2.35
2018	$8.55	$5.31	$5.31	$2.64
2019	$9.24	$5.78	$5.78	$2.92
2020	$9.93	$6.24	$6.24	$3.20
2021	$10.27	$6.46	$6.46	$3.33
2022	$10.62	$6.69	$6.69	$3.45
2023	$10.98	$6.92	$6.92	$3.59
2024	$11.35	$7.17	$7.17	$3.73
2025	$11.74	$7.41	$7.41	$3.86
2026	$12.13	$7.67	$7.67	$4.01
2027	$12.53	$7.94	$7.94	$4.16
2028	$12.95	$8.21	$8.21	$4.32
2029	$13.38	$8.49	$8.49	$4.48
2030	$13.82	$8.78	$8.78	$4.65
2031	$14.28	$9.08	$9.08	$4.82
2032	$14.75	$9.39	$9.39	$5.00
2033	$15.23	$9.70	$9.70	$5.18
2034	$15.73	$10.03	$10.03	$5.37
2035	$16.25	$10.37	$10.37	$5.56
2036	$16.78	$10.71	$10.71	$5.76
2037	$17.32	$11.07	$11.07	$5.97
2038	$17.89	$11.44	$11.44	$6.18
2039	$18.47	$11.82	$11.82	$6.40
2040	$19.06	$12.21	$12.21	$6.62
2041	$19.68	$12.61	$12.61	$6.86
2042	$20.31	$13.03	$13.03	$7.10
2043	$20.96	$13.46	$13.46	$7.34
2044	$21.63	$13.90	$13.90	$7.60
2045	$22.33	$14.35	$14.35	$7.86
2046	$23.04	$14.82	$14.82	$8.13
2047	$23.77	$15.30	$15.30	$8.41
2048	$24.53	$15.80	$15.80	$8.70
2049	$25.31	$16.31	$16.31	$9.00
2050	$26.11	$16.84	$16.84	$9.30
2051	$26.93	$17.38	$17.38	$9.62
2052	$27.78	$17.94	$17.94	$9.94
2053	$28.66	$18.51	$18.51	$10.28
2054	$29.56	$19.10	$19.10	$10.62

Appendix F

Envirornmental Compliance Costs

Environmental Compliance Cost Forecast
(nominal $ per ton)

SO_2:

Year	A	B	C	D
2006	962	883	809	789
2007	1,051	965	883	863
2008	1,148	1,054	965	943
2009	1,255	1,152	1,055	1,030
2010	1,370	1,257	1,151	1,124
2011	1,496	1,374	1,257	1,229
2012	1,635	1,502	1,374	1,343
2013	1,787	1,641	1,502	1,467
2014	1,952	1,793	1,641	1,603
2015	2,132	1,959	1,794	1,750
2016	2,330	2,139	1,959	1,912
2017	2,543	2,337	2,139	2,087
2018	2,776	2,551	2,336	2,280
2019	3,031	2,784	2,549	2,489
2020	3,309	3,040	2,784	2,717
2021	3,616	3,322	3,042	2,969
2022	3,952	3,629	3,324	3,245
2023	4,318	3,966	3,631	3,545
2024	4,719	4,333	3,967	3,873
2025	5,156	4,735	4,335	4,232
2026	5,420	4,910	4,445	4,198
2027	5,697	5,092	4,558	4,165
2028	5,989	5,282	4,674	4,131
2029	6,296	5,477	4,793	4,097
2030	6,619	5,681	4,915	4,064
2031	6,768	5,808	5,026	4,155
2032	6,920	5,939	5,139	4,249
2033	7,076	6,073	5,254	4,344
2034	7,235	6,209	5,373	4,442
2035	7,398	6,349	5,493	4,542
2036	7,564	6,492	5,617	4,644
2037	7,735	6,638	5,743	4,749
2038	7,909	6,787	5,873	4,856
2039	8,087	6,940	6,005	4,965
2040	8,269	7,096	6,140	5,077
2041	8,455	7,256	6,278	5,191
2042	8,645	7,419	6,419	5,308
2043	8,839	7,586	6,564	5,427
2044	9,038	7,757	6,711	5,549
2045	9,242	7,931	6,862	5,674
2046	9,449	8,110	7,017	5,802
2047	9,662	8,292	7,175	5,932
2048	9,879	8,479	7,336	6,066
2049	10,102	8,670	7,501	6,202
2050	10,329	8,865	7,670	6,342
2051	10,561	9,064	7,842	6,484
2052	10,799	9,268	8,019	6,630
2053	11,042	9,477	8,199	6,779
2054	11,291	9,690	8,384	6,932

Environmental Compliance Cost Forecast
(nominal $ per ton)

NO$_X$:

Year	A	B	C	D
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2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	1,745	1,738	1,658	1,617
2010	1,779	1,750	1,804	1,765
2011	1,815	1,762	1,962	1,927
2012	1,958	1,927	2,145	2,106
2013	2,112	2,105	2,344	2,301
2014	2,294	2,300	2,562	2,516
2015	2,506	2,513	2,798	2,747
2016	2,737	2,745	3,057	3,000
2017	2,946	2,997	3,337	3,277
2018	3,173	3,272	3,643	3,578
2019	3,416	3,572	3,978	3,905
2020	3,679	3,900	4,344	4,264
2021	3,589	3,696	3,209	3,452
2022	3,500	3,502	2,372	2,794
2023	3,414	3,318	1,752	2,261
2024	3,330	3,144	1,294	1,831
2025	3,247	2,979	957	1,482
2026	3,325	3,000	1,045	0
2027	3,405	3,020	1,142	0
2028	3,487	3,041	1,248	0
2029	3,570	3,062	1,363	0
2030	3,656	3,082	1,490	0
2031	3,738	3,151	1,523	0
2032	3,822	3,222	1,557	0
2033	3,908	3,295	1,592	0
2034	3,996	3,369	1,628	0
2035	4,086	3,445	1,665	0
2036	4,178	3,522	1,702	0
2037	4,272	3,601	1,741	0
2038	4,368	3,682	1,780	0
2039	4,466	3,765	1,820	0
2040	4,567	3,850	1,861	0
2041	4,670	3,937	1,903	0
2042	4,775	4,025	1,945	0
2043	4,882	4,116	1,989	0
2044	4,992	4,208	2,034	0
2045	5,104	4,303	2,080	0
2046	5,219	4,400	2,126	0
2047	5,336	4,499	2,174	0
2048	5,456	4,600	2,223	0
2049	5,579	4,704	2,273	0
2050	5,705	4,809	2,324	0
2051	5,833	4,918	2,377	0
2052	5,964	5,028	2,430	0
2053	6,099	5,141	2,485	0
2054	6,236	5,257	2,541	0

Environmental Compliance Cost Forecast
(nominal $ per ton)

CO_2:

Year	A	B	C	D
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2006	0	0	0	0
2007	0	0	0	0
2008	0	0	0	0
2009	0	0	0	0
2010	0	7	0	11
2011	0	7	2	13
2012	0	7	4	14
2013	0	8	7	14
2014	0	9	9	16
2015	0	10	11	17
2016	0	10	13	19
2017	0	10	16	21
2018	0	12	19	23
2019	0	12	21	25
2020	0	13	25	28
2021	0	13	27	30
2022	0	15	31	34
2023	0	15	33	36
2024	0	15	37	40
2025	0	16	39	42
2026	0	16	42	46
2027	0	16	45	51
2028	0	17	47	57
2029	0	17	48	61
2030	0	17	49	66
2031	0	18	50	68
2032	0	18	51	69
2033	0	19	52	71
2034	0	19	53	72
2035	0	19	55	74
2036	0	20	56	76
2037	0	20	57	77
2038	0	21	58	79
2039	0	21	60	81
2040	0	22	61	83
2041	0	22	62	85
2042	0	23	64	87
2043	0	23	65	89
2044	0	24	67	91
2045	0	24	68	93
2046	0	25	70	95
2047	0	25	71	97
2048	0	26	73	99
2049	0	27	75	101
2050	0	27	76	103
2051	0	28	78	106
2052	0	28	80	108
2053	0	29	81	111
2054	0	30	83	113

Environmental Compliance Cost Forecast
(nominal $ per lb)

Hg:

Year	A	B	C	D
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2006	-	-	-	-
2007	-	-	-	-
2008	-	-	-	-
2009	-	-	-	-
2010	27,004	27,960	29,622	29,470
2011	28,344	28,827	29,248	29,103
2012	29,750	29,719	28,879	28,741
2013	31,227	30,641	28,515	28,383
2014	33,435	32,516	29,612	29,479
2015	36,518	35,516	32,346	32,198
2016	39,885	38,794	35,330	35,169
2017	43,550	42,357	38,575	38,398
2018	47,552	46,246	41,999	41,923
2019	51,921	50,494	45,988	45,774
2020	56,692	55,131	50,212	49,976
2021	61,944	60,237	54,863	54,607
2022	67,682	65,817	59,946	59,666
2023	73,952	71,913	65,499	65,193
2024	80,803	78,573	71,567	71,234
2025	88,287	85,851	78,196	77,849
2026	96,468	93,807	85,439	85,045
2027	105,404	102,497	93,352	92,923
2028	115,171	111,995	101,999	101,532
2029	125,841	122,372	111,446	110,940
2030	137,500	133,710	121,769	121,216
2031	140,594	136,718	124,509	123,944
2032	143,757	139,794	127,311	126,733
2033	146,991	142,940	130,175	129,584
2034	150,299	146,156	133,104	132,500
2035	153,680	149,444	136,099	135,481
2036	157,138	152,807	139,161	138,529
2037	160,674	156,245	142,292	141,646
2038	164,289	159,761	145,494	144,833
2039	167,986	163,355	148,767	148,092
2040	171,765	167,031	152,115	151,424
2041	175,630	170,789	155,537	154,831
2042	179,582	174,632	159,037	158,315
2043	183,622	178,561	162,615	161,877
2044	187,754	182,578	166,274	165,519
2045	191,978	186,686	170,015	169,243
2046	196,298	190,887	173,840	173,051
2047	200,714	195,182	177,752	176,945
2048	205,230	199,573	181,751	180,926
2049	209,848	204,064	185,841	184,997
2050	214,570	208,655	190,022	189,159
2051	219,397	213,350	194,298	193,415
2052	224,334	218,150	198,669	197,767
2053	229,381	223,059	203,139	202,217
2054	234,543	228,078	207,710	206,767

Appendix G

Financial and Economic Assumptions

I. FPL Capital Structure, Discount Rate, and AFUDC Rate:

a) Projected Capitalization Ratios and Projected Cost of Capital:

Component	Ratio	Cost
Debt	44.2%	7.20%
Preferred	0%	0%
Equity	55.8%	12.30%

b) Projected Discount Rate = 8.93 % for generation costs and 8.82% for all other costs.

c) Projected AFUDC Rates

Year	Rate (%)
2007	7.42
2008	7.77
2009	8.02
2010	8.23
2011	8.38
2012 and beyond	8.50

II. Tax Assumptions:

a) Composite Effective Income Tax Rate (Federal and State tax rates adjusted for federal production tax credits for each unit) =

- 35.100% for generation facilities
- 38.575% for transmission facilities

b) Combined Cycle Book Life = 25 years

c) Combined Cycle Tax Depreciation Life = 20 years

d) Advanced Technology Coal Book Life = 40 years

e) Advanced Technology Coal Tax Depreciation Life = 20 years

f) Transmission Book Life = 40 years

g) Transmission Tax Depreciation Life = 15 years

III. FPL Cost Escalation Assumptions:

Year	Capital	Fixed O&M	Capital Replacement	Variable O&M
2007	3.00%	3.70%	0.80%	0.80%
2008	3.00%	3.60%	-0.10%	-0.10%
2009	3.00%	3.80%	-0.90%	-0.90%
2010	3.00%	3.90%	0.40%	0.40%
2011	3.00%	3.90%	0.40%	0.40%
2012	3.00%	3.80%	0.60%	0.60%
2013	3.00%	3.60%	0.80%	0.80%
2014	3.00%	3.40%	0.70%	0.70%
2015	3.00%	3.40%	0.70%	0.70%
2016	3.00%	3.40%	0.80%	0.80%
2017	3.00%	3.50%	0.60%	0.60%
2018	3.00%	3.50%	0.10%	0.10%
2019	3.00%	3.50%	1.10%	1.10%
2020	3.00%	3.50%	0.90%	0.90%
2021	3.00%	3.60%	0.90%	0.90%
2022	3.00%	3.50%	0.90%	0.90%
2023	3.00%	3.50%	1.00%	1.00%
2024	3.00%	3.50%	1.10%	1.10%
2025	3.00%	3.60%	1.10%	1.10%
2026	3.00%	3.60%	1.10%	1.10%
2027	3.00%	3.60%	1.10%	1.10%
2028	3.00%	3.60%	1.10%	1.10%
2029	3.00%	3.60%	1.10%	1.10%
2030	3.00%	3.60%	1.20%	1.20%
2031	3.00%	3.60%	1.30%	1.30%
2032	3.00%	3.60%	1.30%	1.30%
2033	3.00%	3.60%	1.30%	1.30%
2034	3.00%	3.60%	1.40%	1.40%
2035	3.00%	3.60%	1.40%	1.40%
2036	3.00%	3.60%	1.50%	1.50%
2037	3.00%	3.60%	1.50%	1.50%
2038	3.00%	3.60%	1.50%	1.50%
2039	3.00%	3.60%	1.50%	1.50%
2040	3.00%	3.60%	1.50%	1.50%
2041	3.00%	3.60%	1.50%	1.50%
2042	3.00%	3.60%	1.50%	1.50%
2043	3.00%	3.60%	1.50%	1.50%
2044	3.00%	3.60%	1.50%	1.50%
2045	3.00%	3.60%	1.50%	1.50%
2046	3.00%	3.60%	1.50%	1.50%
2047	3.00%	3.60%	1.50%	1.50%
2048	3.00%	3.60%	1.50%	1.50%
2049	3.00%	3.60%	1.50%	1.50%
2050	3.00%	3.60%	1.50%	1.50%
2051	3.00%	3.60%	1.50%	1.50%
2052	3.00%	3.60%	1.50%	1.50%
2053	3.00%	3.60%	1.50%	1.50%
2054	3.00%	3.60%	1.50%	1.50%

Appendix H

FPL's Generating Unit Options *

New Generation Alternatives	2013	2014	2012	2014	2016	2017
Alternatives:	**980 MW PC**	**980 MW PC**	**3 x 1 CC**	**3 x 1 CC**	**3 x 1 CC**	**2 x 1 CC**
In-Service Year	**2013**	**2014**	**2012**	**2014**	**2016**	**2017**
	Supercritical	Supercritical	G Moderate Duct Fired	"G" UnFired	"G" UnFired	7FA Moderate Duct Fired
	Glades County Unit 1	**Glades County Unit 2**	**West County Unit 3**	**Glades County Unit 1**	**Glades County Unit 2**	**Unsited Filler Unit**
I. CONSTRUCTION ($1,000)						
Grand Total Cost (In Service Year,w/o AFUDC)	$2,795,500	$1,862,900	$734,000	$1,130,000	$1,002,000	$524,000
II. PLANT CHARACTERISTICS (Unit Average)						
Net Sum 95FCapability (mw) - Base	980	980	1115	1119	1119	492
Net Win 35F Capability (mw) - Base	990	990	1246	1250	1250	543
Heat Rate btu/kwh 75F100% -Base	8,800	8,800	6,582	6,560	6,560	6,885
Heat Rate btu/kwh 75F 75% -Base	8,863	8,863	6,724	6,702	6,702	7,182
Heat Rate btu/kwh 75F 50% -Base	9,285	9,285	6,911	6,881	6,881	7,776
Duct Firing-Incremental from Base Sum MW 95F	0	0	104	0	0	48
Duct Firing-Incremental from Base Win MW 35F	n/a	n/a	89	0	0	47
Duct Firing-Incremental from Base Ann Avg Heat Rate 75F	n/a	n/a	8,770	0	0	8,620
Peak Firing- Incremental from Base Sum MW 95F	0	0	0	0	0	13
Peak Firing- Incremental from Base Win MW 35F	n/a	n/a	0	0	0	n/a
Peak Firing- Incremental from Base Ann Avg Heat Rate 75F	n/a	n/a	n/a	n/a	n/a	5,500
Base Operation- Planned Outage Hours/Year	530	530	190	190	190	180
Base Operation- Forced Outage Hours/Year	350	350	96	96	96	88
Duct Firing Operation- Planned Outage Hours/Year	n/a	n/a	n/a	n/a	n/a	n/a
Duct Firing Operation- Forced Outage Hours/Year	n/a	n/a	n/a	n/a	n/a	n/a
Peak Firing Operation- Planned Outage Hours/Year	n/a	n/a	n/a	n/a	n/a	8,672
Peak Firing Operation- Forced Outage Hours/Year	n/a	n/a	n/a	n/a	n/a	0
AVAILABILITY	**EAF- 92% POF- 5% EFOR- 3%**	**EAF- 92% POF- 5% EFOR- 3%**	**EAF- 96.8% POF- 2.1% FOF- 1.1%**	**EAF- 96.8% POF- 2.1% FOF- 1.1%**	**EAF- 96.8% POF- 2.1% FOF- 1.1%**	**EAF- 97% POF- 2% FOF- 1%**
Ramp Rate (MW/Minute)	20	20	30	30	30	20
Minimum Load	392	392	280	280	280	180
III. OPERATION COSTS	**(2013 $)**	**(2014 $)**	**(2012 $)**	**(2014 $)**	**(2016 $)**	**(2017 $)**
Start up Costs (yearly average) in ($1,000,000)	0.10	0.10				
Fixed O&M ($/kw-yr)(Summer Peak Output)	32.62	23.41	3.44	5.53	3.94	13.96
Variable (excl. fuel) ($/mwh) (Summer Peak Output @ 85% CF)	1.744	1.756	0.507	0.515	0.523	0.568
Capital Replace ($/kw-yr)(Summer Peak Output)	2.99	3.01	7.13	7.24	7.35	6.76
Cold Startup Cost (greater than 48 hours off-line)($/startup)	$200,000	$200,000	$20,000	$20,000	$20,000	$20,000
IV. EMISSION RATES						
NOx Emission Rates (lb/mmbtu)	0.050	0.050	0.010	0.010	0.010	0.010
SO2 Emission Rates (lb/mmbtu)	0.040	0.040	0.006	0.006	0.006	0.006
CO2 (lb/mmbtu)	205	205	109	109	109	109
Mecury, Hg (lb/Tbtu) (T=trillion)	1.2000	1.2000	0.000	0.000	0.000	0.000
IV. SPENDING CURVES (1000,w/o AFUDC) $	**(2013 $)**	**(2014 $)**	**(2012 $)**	**(2014 $)**	**(2016 $)**	**(2017 $)**
Year 2017						$28,670
Year 2016					$17,520	$130,020
Year 2015					$218,680	$316,830
Year 2014		$236,400		$18,780	$550,860	$47,120
Year 2013	$255,800	$304,800		$229,310	$209,200	$1,370
Year 2012	$352,200	$463,300	$37,000	$577,340	$5,480	$0
Year 2011	$648,900	$438,400	$184,000	$298,610	$250	
Year 2010	$688,500	$309,600	$450,000	$5,710	$0	
Year 2009	$519,400	$96,600	$61,000	$240		
Year 2008	$304,600	$9,200	$2,000			
Year 2007	$22,800	$4,600	$0			
Year 2006	$3,300	$0				
Year 2005						
Year 2004						

* The resource plans analyzed for this Determination of Need filing included two new nuclear units, one in 2018 and one in 2019. For planning purposes, the assumptions for each nuclear unit were: 1,090 MW in capacity, no capital or O&M costs were assigned, annual availability of 92%, and siting was in SE Florida.

Appendix I

Transmission Interconnection and Integration Costs

Facility	Description		Total Cost	Construction Start	Construction Finish
TF-1	The connection of FGPP 1 and 2 Generator Step Up ("GSU") transformers to the FGPP switchyard, and attendant bus equipment; (TF-1)	$	2,295,000	September-2009	November-2010
TF-2	The FGPP switchyard; (TF-2)	$	19,090,000	September-2009	November-2010
TF-3	The Hendry 500/230 kV Substation; (TF-3)	$	56,035,000	January-2009	November-2010
TF-4	The two 500 kV transmission lines from the FGPP switchyard to the Hendry Substation; (TF-4)	$	123,461,000	March-2009 March-2009	November-2010 November-2011
TF-5	The looping in of the Alva to Corbett 230 kV and the Andytown to Orange River 500 kV transmission lines into the Hendry substation; (TF-5) .	$	172,566,000	May-2010 March-2009	November-2010 November-2011
TF-6	A new 500 kV transmission circuit from the Hendry to Levee substations. This transmission line will be constructed between Hendry and Andytown substations and connected to an existing Andytown to Levee 500 kV line resulting in a Hendry to Levee 500 kV transmission line; (TF-6)	$	96,020,000	March-2009	November-2012
	Total FGPP	**$**	**469,467,000**		

Notes:

1. Costs were estimated in 2007 dollars and then escalated to the year that the expense would be incurred.
2. TF- Transmission Facilities for Fuel Diversisty Expansion Plan with Coal

Appendix J

Transmission Capacity and Energy Loss Estimates

Transmission losses calculated for the year 2012

Plan	**Transmission losses in MW relative to Plan without Coal**	
	2012 Peak Load Level	2012 Average Load Level
Plan with Coal	-14.3	6.2

Transmission losses calculated for the year 2013

Plan	**Transmission losses in MW relative to Plan without Coal**	
	2013 Peak Load Level	2013 Average Load Level
Plan with Coal	-40.3	-21.6

Transmission losses calculated for the year 2014

Plan	**Transmission losses in MW relative to Plan without Coal**	
	2014 Peak Load Level	2014 Average Load Level
Plan with Coal	-6.4	-0.3

Transmission losses calculated for the year 2015

Plan	**Transmission losses in MW relative to Plan without Coal**	
	2015 Peak Load Level	2015 Average Load Level
Plan with Coal	-21.7	11.3

Transmission losses calculated for the year 2016

Plan	**Transmission losses in MW relative to Plan without Coal**	
	2016 Peak Load Level	2016 Average Load Level
Plan with Coal	3.3	-1.5

Appendix K

Transmission Capacity and Energy Loss Cost Estimates:
Calculation of Peak Hour Loss Cost for the Plan with Coal Compared to the Plan without Coal

Discount Rate =	0.0882
Purchase Proxy Starting Cost ($/kw) =	$5.00
Annual Escalation Rate for Proxy Purchase =	2%

	(1)	(2)	(3)	(4)	(5)
				= (1)*(3)*12	= (2)*(4)
Year	Proxy Purchase Cost ($/kw-mo)	Discount Factor	Peak Load Loss (MW)	Peak Hour Capacity Loss Cost Nominal ($ 000)	Peak Hour Capacity Loss Cost NPV ($ 000)
2006	$0.00	1.000	0.00	$0	$0
2007	$0.00	0.919	0.00	$0	$0
2008	$0.00	0.844	0.00	$0	$0
2009	$0.00	0.776	0.00	$0	$0
2010	$0.00	0.713	0.00	$0	$0
2011	$0.00	0.655	0.00	$0	$0
2012	$0.00	0.602	0.00	$0	$0
2013	$0.00	0.553	0.00	$0	$0
2014	$5.00	0.509	(14.30)	($858)	($436)
2015	$5.10	0.467	(40.32)	($2,468)	($1,153)
2016	$5.20	0.429	(6.40)	($400)	($172)
2017	$5.31	0.395	(21.70)	($1,382)	($545)
2018	$5.41	0.363	3.30	$214	$78
2019	$5.52	0.333	3.30	$219	$73
2020	$5.63	0.306	3.30	$223	$68
2021	$5.74	0.281	3.30	$227	$64
2022	$5.86	0.259	3.30	$232	$60
2023	$5.98	0.238	3.30	$237	$56
2024	$6.09	0.218	3.30	$241	$53
2025	$6.22	0.201	3.30	$246	$49
2026	$6.34	0.184	3.30	$251	$46
2027	$6.47	0.169	3.30	$256	$43
2028	$6.60	0.156	3.30	$261	$41
2029	$6.73	0.143	3.30	$266	$38
2030	$6.86	0.132	3.30	$272	$36
2031	$7.00	0.121	3.30	$277	$34
2032	$7.14	0.111	3.30	$283	$31
2033	$7.28	0.102	3.30	$288	$29
2034	$7.43	0.094	3.30	$294	$28
2035	$7.58	0.086	3.30	$300	$26
2036	$7.73	0.079	3.30	$306	$24
2037	$7.88	0.073	3.30	$312	$23
2038	$8.04	0.067	3.30	$318	$21
2039	$8.20	0.061	3.30	$325	$20
2040	$8.37	0.056	3.30	$331	$19
2041	$8.53	0.052	3.30	$338	$18
2042	$8.71	0.048	3.30	$345	$16
2043	$8.88	0.044	3.30	$352	$15
2044	$9.06	0.040	3.30	$359	$14
2045	$9.24	0.037	3.30	$366	$14
2046	$9.42	0.034	3.30	$373	$13
2047	$9.61	0.031	3.30	$381	$12
2048	$9.80	0.029	3.30	$388	$11
2049	$10.00	0.026	3.30	$396	$10
2050	$10.20	0.024	3.30	$404	$10
2051	$10.40	0.022	3.30	$412	$9
2052	$10.61	0.020	3.30	$420	$9
2053	$10.82	0.019	3.30	$429	$8
2054	$11.04	0.017	3.30	$437	$8
				NPV Total ($000) =	($1,179)

Transmission Capacity and Energy Loss Cost Estimates:
Calculation of Annual Energy Loss Cost for the Plan with Coal Compared to the Plan without Coal

On-Peak Hours =	876	(or 10% of all hours)
Off-Peak Hours =	6,570	
Discount Factor =	0.0882	

Year	(1) On-Peak Marginal Energy Cost ($/mwh)	(2) Off-Peak Marginal Energy Cost ($/mwh)	(3) Discount Factor	(4) Peak Load Loss (MW)	(5) = (4)*On-Peak Hours On - Peak Hours Annual Energy Loss (MWH)	(6) = (1)*(5)/1000 On - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	(7) Average Load Loss (MW)	(8) = (7)*Off-Peak Hours Off - Peak Hours Annual Energy Loss (MWH)	(9) = (2)*(8)/1000 Off - Peak Hours Annual Energy Loss Cost Nominal ($ 000)	(10) = (6) + (9) Total Annual Energy Loss Cost Nominal ($ 000)	(11) = (3)*(10) Total Annual Energy Loss Cost NPV ($ 000)
2006	0	0	1.000	0	0	$0	0	0	$0	$0	$0
2007	$127.50	$104.78	0.919	0	0	$0	0	0	$0	$0	$0
2008	$130.77	$104.82	0.844	0	0	$0	0	0	$0	$0	$0
2009	$115.34	$84.87	0.776	0	0	$0	0	0	$0	$0	$0
2010	$109.00	$79.49	0.713	0.00	0	$0	0.00	0	$0	$0	$0
2011	$98.64	$71.47	0.655	0.00	0	$0	0.00	0	$0	$0	$0
2012	$105.39	$79.31	0.602	(14.30)	(12,527)	($1,320)	6.21	40,800	$3,236	$1,915	$1,153
2013	$108.51	$81.57	0.553	(40.32)	(35,320)	($3,833)	(21.55)	(141,584)	($11,549)	($15,382)	($8,512)
2014	$111.29	$80.70	0.509	(6.40)	(5,606)	($624)	(0.31)	(2,037)	($164)	($788)	($401)
2015	$117.24	$82.13	0.467	(21.70)	(19,009)	($2,229)	11.28	74,110	$6,087	$3,858	$1,803
2016	$125.97	$90.41	0.429	3.30	2,891	$364	(1.47)	(9,658)	($873)	($509)	($219)
2017	$135.17	$96.14	0.395	3.30	2,891	$391	(1.47)	(9,658)	($929)	($538)	($212)
2018	$143.56	$101.28	0.363	3.30	2,891	$415	(1.47)	(9,658)	($978)	($563)	($204)
2019	$151.79	$101.85	0.333	3.30	2,891	$439	(1.47)	(9,658)	($984)	($545)	($182)
2020	$162.40	$110.91	0.306	3.30	2,891	$469	(1.47)	(9,658)	($1,071)	($602)	($184)
2021	$171.13	$121.69	0.281	3.30	2,891	$495	(1.47)	(9,658)	($1,175)	($681)	($192)
2022	$174.99	$120.47	0.259	3.30	2,891	$506	(1.47)	(9,658)	($1,163)	($658)	($170)
2023	$180.15	$121.55	0.238	3.30	2,891	$521	(1.47)	(9,658)	($1,174)	($653)	($155)
2024	$185.79	$124.18	0.218	3.30	2,891	$537	(1.47)	(9,658)	($1,199)	($662)	($145)
2025	$192.32	$128.22	0.201	3.30	2,891	$556	(1.47)	(9,658)	($1,238)	($682)	($137)
2026	$197.05	$131.46	0.184	3.30	2,891	$570	(1.47)	(9,658)	($1,270)	($700)	($129)
2027	$202.10	$133.39	0.169	3.30	2,891	$584	(1.47)	(9,658)	($1,288)	($704)	($119)
2028	$208.04	$137.66	0.156	3.30	2,891	$601	(1.47)	(9,658)	($1,330)	($728)	($113)
2029	$214.63	$141.80	0.143	3.30	2,891	$620	(1.47)	(9,658)	($1,369)	($749)	($107)
2030	$220.99	$145.61	0.132	3.30	2,891	$639	(1.47)	(9,658)	($1,406)	($767)	($101)
2031	$225.38	$149.03	0.121	3.30	2,891	$652	(1.47)	(9,658)	($1,439)	($788)	($95)
2032	$229.19	$152.75	0.111	3.30	2,891	$663	(1.47)	(9,658)	($1,475)	($813)	($90)
2033	$237.83	$158.28	0.102	3.30	2,891	$688	(1.47)	(9,658)	($1,529)	($841)	($86)
2034	$239.84	$161.68	0.094	3.30	2,891	$693	(1.47)	(9,658)	($1,561)	($868)	($81)
2035	$243.30	$166.61	0.086	3.30	2,891	$703	(1.47)	(9,658)	($1,609)	($906)	($78)
2036	$254.22	$172.09	0.079	3.30	2,891	$735	(1.47)	(9,658)	($1,662)	($927)	($73)
2037	$258.31	$177.33	0.073	3.30	2,891	$747	(1.47)	(9,658)	($1,713)	($966)	($70)
2038	$251.38	$182.06	0.067	3.30	2,891	$727	(1.47)	(9,658)	($1,758)	($1,032)	($69)
2039	$251.55	$187.58	0.061	3.30	2,891	$727	(1.47)	(9,658)	($1,812)	($1,084)	($67)
2040	$256.22	$193.34	0.056	3.30	2,891	$741	(1.47)	(9,658)	($1,867)	($1,127)	($64)
2041	$258.88	$199.18	0.052	3.30	2,891	$748	(1.47)	(9,658)	($1,924)	($1,175)	($61)
2042	$261.58	$205.20	0.048	3.30	2,891	$756	(1.47)	(9,658)	($1,982)	($1,226)	($58)
2043	$264.30	$211.40	0.044	3.30	2,891	$764	(1.47)	(9,658)	($2,042)	($1,278)	($56)
2044	$267.05	$217.78	0.040	3.30	2,891	$772	(1.47)	(9,658)	($2,103)	($1,331)	($54)
2045	$269.82	$224.36	0.037	3.30	2,891	$780	(1.47)	(9,658)	($2,167)	($1,387)	($51)
2046	$272.63	$231.14	0.034	3.30	2,891	$788	(1.47)	(9,658)	($2,232)	($1,444)	($49)
2047	$275.47	$238.12	0.031	3.30	2,891	$796	(1.47)	(9,658)	($2,300)	($1,503)	($47)
2048	$278.33	$245.31	0.029	3.30	2,891	$805	(1.47)	(9,658)	($2,369)	($1,565)	($45)
2049	$281.23	$252.72	0.026	3.30	2,891	$813	(1.47)	(9,658)	($2,441)	($1,628)	($43)
2050	$284.15	$260.36	0.024	3.30	2,891	$821	(1.47)	(9,658)	($2,515)	($1,693)	($41)
2051	$287.11	$268.22	0.022	3.30	2,891	$830	(1.47)	(9,658)	($2,590)	($1,761)	($39)
2052	$290.09	$276.33	0.020	3.30	2,891	$839	(1.47)	(9,658)	($2,669)	($1,830)	($37)
2053	$293.11	$284.67	0.019	3.30	2,891	$847	(1.47)	(9,658)	($2,749)	($1,902)	($36)
2054	$296.16	$293.27	0.017	3.30	2,891	$856	(1.47)	(9,658)	($2,832)	($1,976)	($34)
										NPV Total ($000) =	($9,752)

Appendix L

FPL's Approved DSM Plan

FPL's Current DSM Programs

FPL's currently approved DSM programs are summarized as follows:

Residential Conservation Service: This is an energy audit program designed to assist residential customers in understanding how to make their homes more energy-efficient through the installation of conservation measures/practices.

Residential Building Envelope: This program encourages the installation of energy-efficient ceiling insulation, reflective roofs, and roof membranes in residential dwellings that utilize whole-house electric air conditioning.

Duct System Testing and Repair: This program encourages demand and energy conservation through the identification of air leaks in whole-house air conditioning duct systems and by the repair of these leaks by qualified contractors.

Residential Air Conditioning: This is a program to encourage customers to purchase higher efficiency central cooling and heating equipment.

Residential Load Management (On-Call): This program offers load control of major appliances/household equipment to residential customers in exchange for monthly electric bill credits.

New Construction (BuildSmart): This program encourages the design and construction of energy-efficient homes that cost-effectively reduce coincident peak demand and energy consumption.

Residential Low Income Weatherization: This program addresses the needs of low-income housing retrofits by providing monetary incentives to various housing authorities including: weatherization agency providers (WAPS), non-weatherization agency providers (non-WAPS), and other providers approved by FPL. The incentives are used by these providers to leverage their funds to increase the overall energy efficiency of the homes they are retrofitting.

Business Energy Evaluation: This program encourages energy efficiency in both new and existing businesses by identifying DSM opportunities and providing recommendations to business customers.

Business Heating, Ventilating, and Air Conditioning: This program encourages the use of high-efficiency heating, ventilation, and air conditioning (HVAC) systems for business customers.

Business Efficient Lighting: This program encourages the installation of energy-efficient lighting measures for business customers.

Business Custom Incentive: This program encourages business customers to implement unique energy conservation measures or projects not covered by other FPL programs.

Commercial/Industrial Load Control: This program reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits. (This program was closed to new participants in 2000).

Commercial Demand Reduction: This program, which started in 2002, is similar to the Commercial/Industrial Load Control program mentioned above. It reduces peak demand by controlling customer loads of 200 kW or greater during periods of extreme demand or capacity shortages in exchange for monthly electric bill credits.

Business Building Envelope: This program encourages the installation of energy-efficient building envelope measures such as: roof/ceiling insulation, reflective roof coatings, and window treatments for business customers.

Business On Call: This program offers load control of central air conditioning units to both small non–demand-billed, and medium demand-billed, business customers in exchange for monthly electric bill credits.

<u>Business Water Heating:</u> This program encourages the installation of energy-efficient water heating equipment such as heat pump water heaters and heat recovery units for business customers.

<u>Business Refrigeration:</u> This program encourages the installation of qualifying controls and equipment that reduce electric strip heater usage in refrigeration equipment for business customers.

FPL's Renewable Program

<u>Green Power Pricing:</u> In November of 2004, FPL launched its Green Power Pricing Research Project (GPPRP) that was marketed as the *Sunshine Energy®* program. The object of the Project was to allow residential customers to sign up voluntarily and pay for energy produced by renewable resources, thus fostering the development of supplies of renewable energy that would not otherwise be developed. Project participants paid a monthly premium of $9.75 per month for a 1,000 kWh block of renewable energy attributes. To supply the renewable energy for the Project, FPL entered into a contract with a supplier for the purchase of tradable renewable energy credits (TRECs). In addition, for every 10,000 participants, FPL agreed to install 150 kw of photovoltaic capacity in Florida. As a result of this Project, construction of a 250 kW site in Sarasota is currently in progress with expected completion in early 2007. There are also several other smaller projects underway that will add additional photovoltaic capacity.

On September 17, 2006, FPL filed a petition with the Commission to convert the GPPRP to a permanent program and to extend the program to business customers. On December 1, 2006, the Commission issued Order No. PSC-06-0924-TRF-EI in Docket No. 060577-EI approving this request.

FPL's Research and Development Initiatives

FPL continues to support research and development activities. Historically, FPL has performed extensive DSM research and development. FPL will continue such activities, not only through its Conservation Research and Development program (discussed below), but also through individual research projects. These efforts will examine a wide variety of technologies that build on prior FPL research and will expand the research to new and promising technologies as they emerge.

Conservation Research and Development Program: FPL's Conservation Research and Development Program is designed to evaluate emerging conservation technologies to determine which are worthy of pursuing for program development and approval. FPL has researched a wide variety of technologies such as: condenser coil cleaner and coating, ultraviolet lights for evaporator coils, Energy Recovery Ventilators (ERV), fuel cell demonstrations, carbon dioxide (CO2) ventilation control, two-speed air handlers, and duct plenum repair. Many of the technologies examined have resulted in enhancements to existing programs or the development of new programs such as: Residential New Construction, Business Building Envelope, and Business On Call. FPL is currently investigating several technologies including: Cromer Cycle HVAC, commercial kitchen exhaust hoods, HVAC optimizers, and commercial refrigeration flow controls.

On Call Incentive Reduction Pilot: In March 2003, FPL received FPSC approval to perform a pilot for its On Call Program. Under the pilot, FPL is offering to new participants a residential load control service similar to the On Call Program at a reduced incentive level. The offering of this Pilot allows FPL to test its market research data and gauge whether FPL can repackage its current residential load control service, minimize customer attrition, achieve current goals for residential load control, and, ultimately, change On Call incentive levels without damaging FPL system reliability. This pilot will be completed in 2007.

Appendix M

Clean Coal Technology Selection Study

Final Report

January 2007

BLACK & VEATCH
building a world of difference®

ENERGY WATER INFORMATION GOVERNMENT

FPL.

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Acronyms

AFBC	Atmospheric Fluidized Bed Combustion
AGR	Acid Gas Removal
AQCS	Air Quality Control Systems
ASML	Above Mean Sea Level
ASU	Air Separation Unit
BACT	Best Available Control Technology
BFP	Boiler Feed Pump
Ca/S	Calcium to Sulfur
CaO	Calcium Oxide
CaS	Calcium Sulfide
$CaSO_4$	Calcium Sulfate
CCPI	Clean Coal Power Initiative
CCRB	Clean Coal Review Board
CFB	Circulating Fluidized Bed
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COD	Commercial Operation Date
COP	ConocoPhillips
COS	Carbonyl Sulfide
CTG	Combustion Turbine Generator
DA	Deaerator
DCS	Distributed Control System
DLN	Dry Low NO_x
DOE	Department of Energy
EIS	Environmental Impact Statement
EPC	Engineering, Procurement, and Construction
EPRI	Electric Power Research Institute
ESP	Electrostatic Precipitator
FBC	Fluidized Bed Combustion
FEED	Front End Engineering Design
FGR	Flue Gas Recirculation
FPL	Florida Power & Light
FWH	Feedwater Heater
FGPP	FPL Glades Power Park

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GE	General Electric
GEC	Gasification Engineering Corporation
H_2S	Hydrogen Sulfide
H_2SO_4	Sulfuric Acid
HCl	Hydrogen Chloride
HCN	Hydrogen Cyanide
HHV	Higher Heating Value
HP	High-Pressure
HRSG	Heat Recovery Steam Generator
IDC	Interest During Construction
IGCC	Integrated Gasification Combined Cycle
IP	Intermediate-Pressure
ISO	International Organization for Standardization
KBR	Kellogg Brown and Root
LHV	Lower Heating Value
LP	Low-Pressure
MDEA	Methyl Diethanol Amine
MHI	Mitsubishi Heavy Industries
NEPA	National Environmental Policy Act
NGCC	Natural Gas Combined Cycle
NH_3	Ammonia
NO_x	Oxides of Nitrogen
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
OFA	Overfire Air
OP	Over Pressure
OUC	Orlando Utilities Commission
PC	Pulverized Coal
Petcoke	Petroleum Coke
PJFF	Pulse Jet Fabric Filter
PM_{10}	Particulate Matter (filterable 10 microns and less)
PRB	Powder River Basin
PSDF	Power Systems Development Facility
PUCO	Public Utilities Commission of Ohio
SCR	Selective Catalytic Reduction
SDA	Spray Dryer Absorber

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SNCR	Selective Noncatalytic Reduction
SO_2	Sulfur Dioxide
SPC	Subcritical Pulverized Coal
SCPC	Supercritical Pulverized Coal
SPG	Siemens Power Generation
STG	Steam Turbine Generator
SWEPCO	Southwestern Electric Power Company
TC4F	Tandem-Compound Four Flow
TRIG	Transport Reactor Integrated Gasification
US	United States
USCPC	Ultra Supercritical Pulverized Coal
VWO	Valves Wide Open

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Units of Measure

¢	Cents
$	Dollar
%	Percent
% wt	Percent weight
° F	Degrees Fahrenheit
Btu	British thermal unit
ft	foot
ft^3	cubic feet
h	hour
in. HgA	inches of mercury, absolute
kW	kilowatt
lb	pound
ltpd	long tons per day (2,240 lb/day)
m^3	cubic meters
MBtu	million British thermal unit
mg	milligram
MW	megawatt
MWh	megawatt-hour
N	Newton
ppb	parts per billion
ppm	parts per million
ppmvd	parts per million, volumetric dry
psia	pounds per square inch, absolute
scf	standard cubic feet
sec	second
stpd	short tons per day (2,000 lb/day)
tpd	tons per day
yr	year

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1.0 Executive Summary

1.1 Introduction

This study is in connection with Florida Power & Light's (FPL) generation expansion project investigations for the addition of a nominal 2,000 MW of capacity. FPL has previously identified a need to diversify its fuel consumption. Therefore, this study investigates only coal-fueled technologies. The study compared subcritical pulverized coal (SPC), ultrasupercritical pulverized coal (USCPC), circulating fluidized bed (CFB), and integrated gasification combined cycle (IGCC). These baseload pulverized coal (PC), CFB, and IGCC technologies comprise the clean coal options available for consideration to meet FPL's generation expansion project needs in the 2012 to 2014 time period.

This study provides technology descriptions, plant descriptions, and screening level estimates of performance, capital costs, and operations and maintenance (O&M) costs for the various power generation technologies considered. Performance and cost estimates were based on assumptions made by Black & Veatch, in conjunction with FPL, for site and ambient conditions, cycle arrangements, air quality control systems (AQCS), and analysis of the proposed fuel. A busbar economic analysis was also performed to compare the technologies.

1.2 Plant Descriptions

Black & Veatch developed screening level performance and cost estimates for each of the technologies: SPC, USCPC, CFB, and IGCC. The required capacity would be met by installing blocks of power at the site to obtain a nominal 2,000 MW net. The fuels used for the performance and cost estimates consisted of blends of Central Appalachian coal, Colombian coal, and petroleum coke (petcoke). The PC and CFB cases utilized a blend of 40 percent Central Appalachian coal, 40 percent Colombian coal, and 20 percent petcoke – referred to as the AQCS Blend. The IGCC case utilized a blend of 25 percent Central Appalachian coal, 25 percent Colombian coal, and 50 percent petcoke – referred to as the IGCC Blend. All blend percentages are by weight. The technologies, plant sizes, and arrangements that were considered for this study are shown in Table 1-1.

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Table 1-1. Summary of Power Generation Technologies

Case	Technology Type	Single Unit Output, MW	Net Plant Output, MW	Configuration	Fuel Supply
1	SPC	500	2,000	4 Boilers 4 STGs	AQCS Blend
2	USCPC	980	1,960	2 Boilers 2 STGs	AQCS Blend
3	CFB	497	1,988	8 Boilers 4 STGs	AQCS Blend
4	IGCC	940	1,880	6 GE Radiant Gasifiers 6 CTGs 6 HRSGs 2 STGs	IGCC Blend

STG–Steam Turbine Generator
CTG–Combustion Turbine Generator
HRSG–Heat Recovery Steam Generator

1.3 Overall Assumptions

For the basis of the performance estimates, the site conditions of the proposed greenfield FPL Glades Power Park (FGPP) in Glades County, Moore Haven, Florida were used. The site conditions were provided to Black & Veatch by FPL. Performance estimates were developed for both the hot day and the average day ambient conditions. Following are the overall assumptions, which were consistent among all of the technologies:

- Elevation–20 feet above mean sea level (ASML).
- Ambient barometric pressure–14.67 psia.
- Hot day ambient conditions:
  Dry-bulb temperature–95° F.
  Relative humidity–50 percent.
- Average day ambient conditions:
  Dry-bulb temperature–75° F.
  Relative humidity–60 percent.
- The assumed fuel is a blend of three different fuels. The ultimate analysis of the AQCS and IGCC Blend fuels (which were used to determine performance and cost estimates) is provided in Table 1-2.

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- AQCS equipment was selected to develop performance and cost estimates, based on Black & Veatch experience. Actual AQCS equipment would be selected to comply with federal New Source Performance Standards (NSPS), be subject to a Best Available Control Technology (BACT) review, and achieve the emission levels shown in Table 5-4.
- Condenser performance was based on Black & Veatch experience. The expected condenser back pressures were supplied for hot and average day ambient conditions.

Table 1-2. Ultimate Fuel Analysis

Fuel	AQCS Blend	IGCC Blend
Carbon, % wt	69.85	73.28
Sulfur, % wt	1.98	3.77
Oxygen, % wt	5.51	3.74
Hydrogen, % wt	4.35	3.96
Nitrogen, % wt	1.37	1.46
Chlorine, % wt	0.07	0.05
Ash, % wt	7.68	4.99
Water, % wt	9.18	8.74
HHV, Btu/lbm	12,300	12,800
HHV–Higher Heating Value.		

1.4 Performance Estimates

1.4.1 PC and CFB Cases

The cases were evaluated on a consistent basis to show the effects of technology selection on project performance. The performance estimates were generated for single units that would be installed at a multiple unit greenfield site. Full-load performance estimates for each of the PC and CFB cases are presented in Table 1-3.

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Table 1-3. PC and CFB Coal Performance Estimates, per Unit

Technology Fuel	SPC AQCS Blend	USCPC AQCS Blend	CFB AQCS Blend
Performance on Average Ambient Day at 20 ft ASML, Clean and New Equipment			
Steam Conditions, psia/° F/° F	2,415/1,050/1,050	3,715/1,112/1,130	2,415/1,050/1,050
Fuel Input, Mbtu/h	4,600	8,480	4,730
Boiler Efficiency (HHV), percent	88.9	88.9	87.0
Heat to Steam (HHV), Mbtu/h	4,090	7,545	4,200
Gross Single Unit Output, MW	550	1,054	556
Total Auxiliary Load, MW	50	74	59
Net Single Unit Output, MW	500	980	497
Gross Turbine Heat Rate, Btu/kWh	7,450	7,140	7,540
Condenser Pressure, in. HgA	2.2	2.1/1.7	2.2
NPHR (HHV), Btu/kWh	9,210	8,660	9,510
Net Plant Efficiency (HHV), percent	37.0	39.4	35.9
Performance on Hot Day at 20 ft ASML, Clean and New Equipment			
Net Single Unit Output, MW	494	976	491
NPHR (HHV), Btu/kWh	9,340	8,690	9,640
Performance On Average Ambient Day at 20 ft ASML, Maximum Degradation (1.0% heat rate and 1.0% net plant output)			
Net Single Unit Output, MW	495	970	492
NPHR (HHV), Btu/kWh	9,300	8,750	9,610

Note:
USCPC option has dual condensers, therefore both pressures are listed.
No margins were applied to performance estimates.

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1.4.2 IGCC Cases

Full-load performance estimates were developed for the IGCC case. The IGCC case was evaluated on a consistent basis with the PC and CFB cases with respect to site and ambient conditions to show the effects of technology selection on project performance. Performance estimates for the IGCC case using GE Radiant gasifiers are presented in Table 1-4. IGCC performance is presented in a separate table from the PC and CFB cases because the performance parameters are slightly different.

Table 1-4. GE Radiant IGCC Performance Estimates, per Unit

Fuel	IGCC Blend
Combined Cycle Configuration	3 x 1 GE 7FB
Performance on Average Day at 20 ft ASML, Clean and New Equipment	
Coal to Gasifiers, MBtu/h	8,400
Gasifier Cold Gas Efficiency, % (Clean Syngas HHV/Coal HHVx100)	74
CTG Heat Rate (LHV), Btu/kWh	8,370
CTG(s) Gross Power, MW	687
Steam Turbine Gross Power, MW	451
Syngas Expander Power, MW	5
Total Gross Power, MW	1,143
Aux. Power Consumption, MW	203
Net Power, MW	940
Net Plant Heat Rate (HHV), Btu/kWh	8,990
Net Plant Efficiency (HHV), Btu/kWh	38.0
Performance on Hot Day at 20 ft ASML, Clean and New Equipment	
Net Power, MW	902
Net Plant Heat Rate (HHV), Btu/kWh	9,360
Performance on Average Day at 20 ft ASML, Maximum Degradation (2.5% heat rate and 2.5% net power output)	
Net Power, MW	917
Net Plant Heat Rate (HHV), Btu/kWh	9,215
Note: Based on publicly available data from technology vendor. No margins were applied to performance estimates.	

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1.5 Cost Estimates

1.5.1 Capital Costs

Screening level overnight capital cost estimates for the four technologies were estimated on an engineering, procurement, and construction (EPC) basis, exclusive of Owner's costs. The estimates are expressed in 2006 United States (US) dollars and are included in Table 1-5. The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis. The estimates were based on Black & Veatch proprietary estimating templates and experience. These estimates are screening-level estimates prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc. Cost estimates are made using consistent methodology between technologies, so while the absolute cost estimates are expected to vary within a band of accuracy, the relative accuracy between technologies is better.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry.

Table 1-5. EPC Capital Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
EPC Cost, 2006$MM	3,078	2,646	3,240	3,541
Unit EPC Cost, 2006$/kW	**1,540**	**1,350**	**1,630**	**1,880**
Escalation to 2012$	490	421	516	564
Subtotal - EPC Cost 2012$	*3,568*	*3,067*	*3,756*	*4,105*
Owner's Costs, 2012$	1,218	1,153	1,236	1,411
IDC, 2012$	1,063	914	1,119	1,223
Project Cost, 2012$	*5,849*	*5,134*	*6,111*	*6,739*
Unit EPC Cost, 2012$/kW	**2,925**	**2,619**	**3,074**	**3,585**

1.5.2 Nonfuel O&M Costs

Preliminary screening level estimates of O&M expenses for the technologies were developed. The O&M estimates were derived from other detailed estimates developed by

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Black & Veatch, based on vendor estimates and recommendations; actual performance information gathered from in-service units; and representative costs for staffing, materials, and supplies. The nonfuel O&M cost estimates, including fixed and variable costs, are shown in Table 1-6.

Table 1-6. O&M Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
Capacity Factor, percent	92.0	92.0	88.0	80.0
Annual Generation, GWh	16,100	15,800	15,300	13,200
Fixed Costs, 2006$, (1,000s)	35,780	27,500	38,800	47,810
Fixed Costs, 2006$/kW	17.89	14.03	19.54	25.43
Variable Costs, 2006$ (1,000s)	45,130	47,500	68,000	80,120
Variable Costs, 2006$/MWh	2.94	2.86	4.44	6.07
Fixed Costs, 2012$, (1,000s)	41,480	31,870	45,050	55,420
Fixed Costs, 2012$/kW	20.74	16.26	22.66	29.48
Variable Costs, 2012$ (1,000s)	54,900	52,300	78,600	92,930
Variable Costs, 2012$/MWh	3.41	3.31	5.14	7.04

1.6 Busbar Cost Analysis

A levelized busbar cost analysis was performed using several sets of data. These include:

- Economic criteria provided by FPL
- Fuel forecasts provided by FPL
- Performance estimates for the PC, CFB, and IGCC cases listed in Table 1-3 and Table 1-4.
- EPC capital cost estimates listed in Table 1-5,
- O&M cost estimates listed in Table 1-6.

The PC and CFB cases were run with 40 year book and 20 year tax lives. The IGCC case was run with 25 year book and 20 tax lives.

Performance was based on the annual average day conditions. The capacity factors for the PC, CFB, and IGCC units were assumed to be 92, 88, and 80 percent, respectively.

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The results of the busbar analysis are provided in Table 1-7. Results are provided in 2012$. Several cases were run:

- Degraded performance at average ambient conditions with no emissions allowance cost included.
- New and clean performance at average ambient conditions with no emissions allowance cost included.
- Degraded performance at average ambient conditions with emissions allowance cost included for oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and mercury (Hg). Emission allowance costs were estimated by multiplying a forecasted allowance cost by the total annual emissions of each pollutant based on the assumed control limits minus annual emission allocations for FGPP.
- New and clean performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, and Hg.
- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, Hg, and carbon dioxide (CO_2) using the 2005 Bingaman carbon tax proposal. No carbon capture was included.

From the analysis, the USCPC unit is the most cost effective technology.

Table 1-7. Busbar Cost Analysis Results, ¢/kWh

Case	SPC	USCPC	CFB	IGCC
Degraded performance, w/o emissions	9.56	8.63	10.54	12.69
New and clean performance, w/o emissions	9.47	8.54	10.43	12.38
Degraded performance, w/ emissions	9.68	8.74	10.66	12.81
New and clean performance, w/ emissions	9.58	8.65	10.56	12.50
Degraded performance, w/ emissions including CO_2	10.96	9.94	11.99	14.00

Note: Results were based on economic criteria from Table 7-1, fuel forecasts from Table 7-2, and the inputs from Table 7-3. These results are based on the maximum assumed capacity factors at average ambient conditions. Results are based on 2012 cost estimates.

Three charts are provided to illustrate sensitivities of the busbar cost analysis. Figure 1-1 shows a breakdown of the components of the base case busbar cost without emissions allowances. Fuel and capital requirements make up the majority of the total busbar costs. Variations in these two cost categories will have the largest effect on the

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estimated busbar cost for any technology. Figures 1-2 and 1-3 are similar to Figure 1-1, but show the effect of adding the cost of emissions allowances. Figure 1-2 shows the incremental cost of adding allowance costs for NO_x, SO_2 and Hg. It can be seen that variations in emissions translate to minimal cost variations between the technologies. Figure 1-3 shows that the effect of adding CO_2 allowances (using the Bingaman case with no carbon capture). The carbon tax causes a noticeable increase to the absolute busbar costs, but because CO_2 emissions are relatively equal between technologies there is no effect on the rank order of busbar costs. All of the cases illustrated are based on degraded performance.

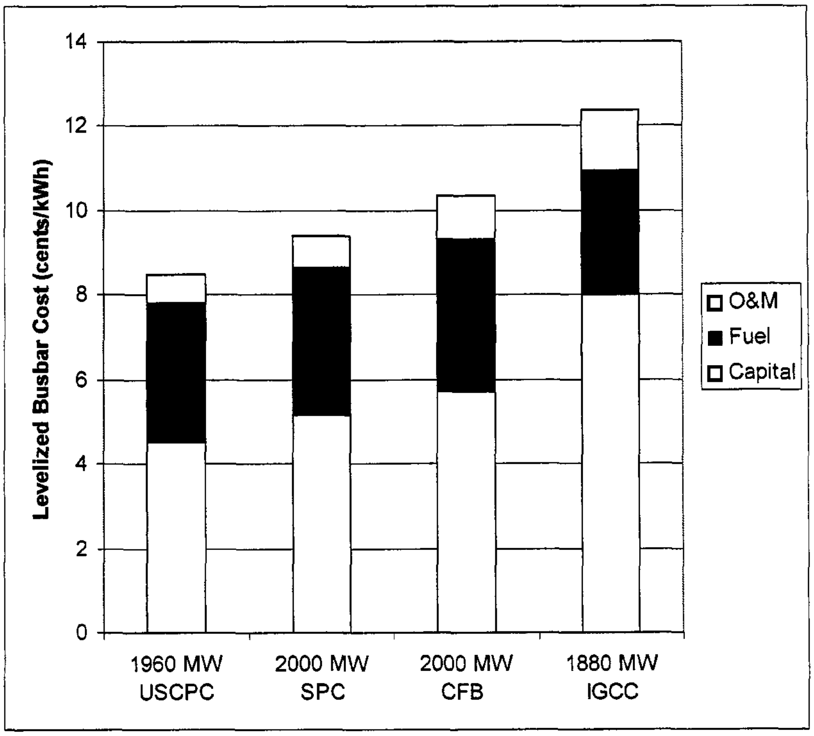

Figure 1-1. Busbar Cost Component Analysis without Emissions

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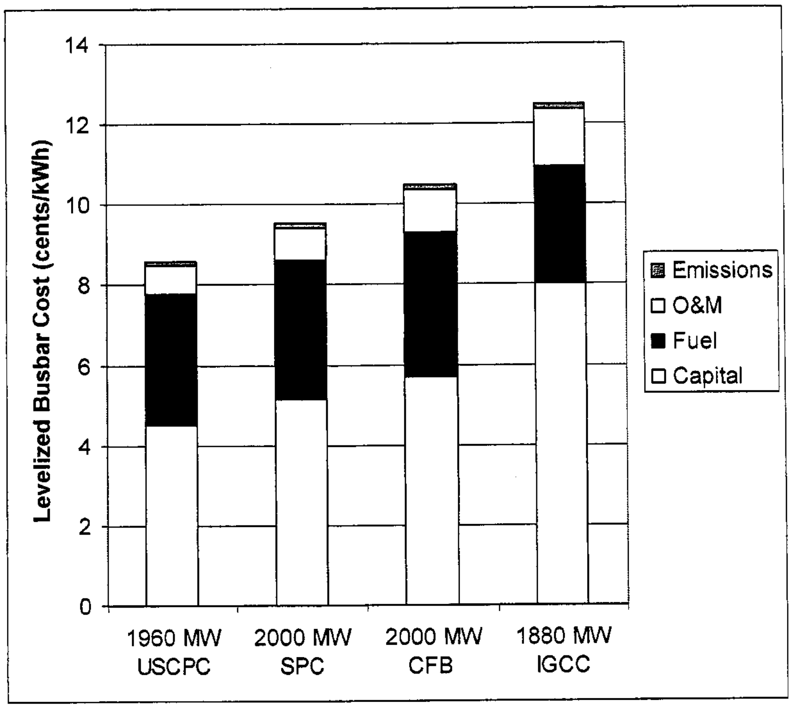

Figure 1-2. Busbar Cost Component Analysis with Emissions

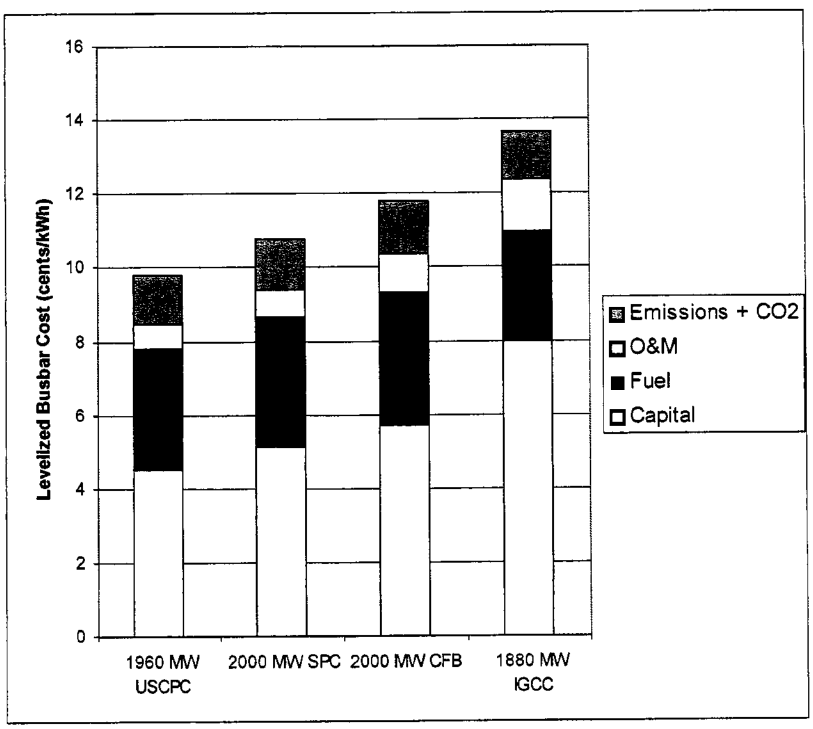

Figure 1-3. Busbar Cost Component Analysis with CO_2

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A sensitivity case was run that included potential costs of carbon capture. There have been many studies performed by other parties to quantify the cost of capturing carbon. Because study of the potential cost of carbon capture was not a focus of this effort, high level assessments have been made to provide a representation of the cost of carbon capture and show the relative effect of this added cost on the economic comparison between technologies.

A review of recent literature, including the US EPA "Environmental Footprints and Cost of Coal-Based Integrated Gasification and Pulverized Coal Technologies", the Alstom chilled ammonia position paper, and Black & Veatch work indicates a probable range of carbon capture as shown in Table 1-8.

Table 1-8. Probable Carbon Capture Costs, $/Avoided Ton CO_2.

Case	Low Cost	High Cost
Post-Combustion, 2006$	20	40
Pre-Combustion, 2006$	20	30

The cost range for pre-combustion is representative of current literature values published by technology neutral sources. The cost range for post-combustion uses Alstom's cost projection for their technology to establish the low value and then makes an assumption that the commercial cost could be 100 percent more for the high value. Estimated costs for other post combustion carbon capture systems published in other studies are higher than those published for this unique Alstom technology.

When these costs are added to the busbar cost analysis, with adjustments for output and net plant heat rate made as needed, the percentage increase of busbar cost over the base case analysis for new & clean conditions are as shown in Table 1-9.

Table 1-9. Probable Busbar Percentage Cost Increase with Carbon Capture and Emissions Allowances.

Case	Low Cost	High Cost
SPC	20	30
USCPC	20	30
CFB	20	30
IGCC	20	25

Note:

Assumes 90 percent carbon capture for conditions at average ambient temperatures compared to case with no emissions allowance costs. Includes emissions allowances for NO_x, SO_2, Hg, and emitted CO_2 using the 2005 McCain cost proposal.

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A sensitivity analysis was run to show the effect variations in capacity factor have on economic analysis outputs. Figures 1-4 and 1-5 show the variations in busbar cost in cents per unit of generation (¢/kWh) and net levelized annual cost in dollars per unit of net plant output ($/kW) versus annual capacity factor. The sensitivity analysis was run over a range of capacity factors, from 40 percent to the maximum for each technology. The net plant heat rate was kept constant for all capacity factors, assuming full load operation. While all of the technologies have dramatic changes in busbar and net levelized annual cost across the range of capacity factors, the rank order of costs does not vary with capacity factor.

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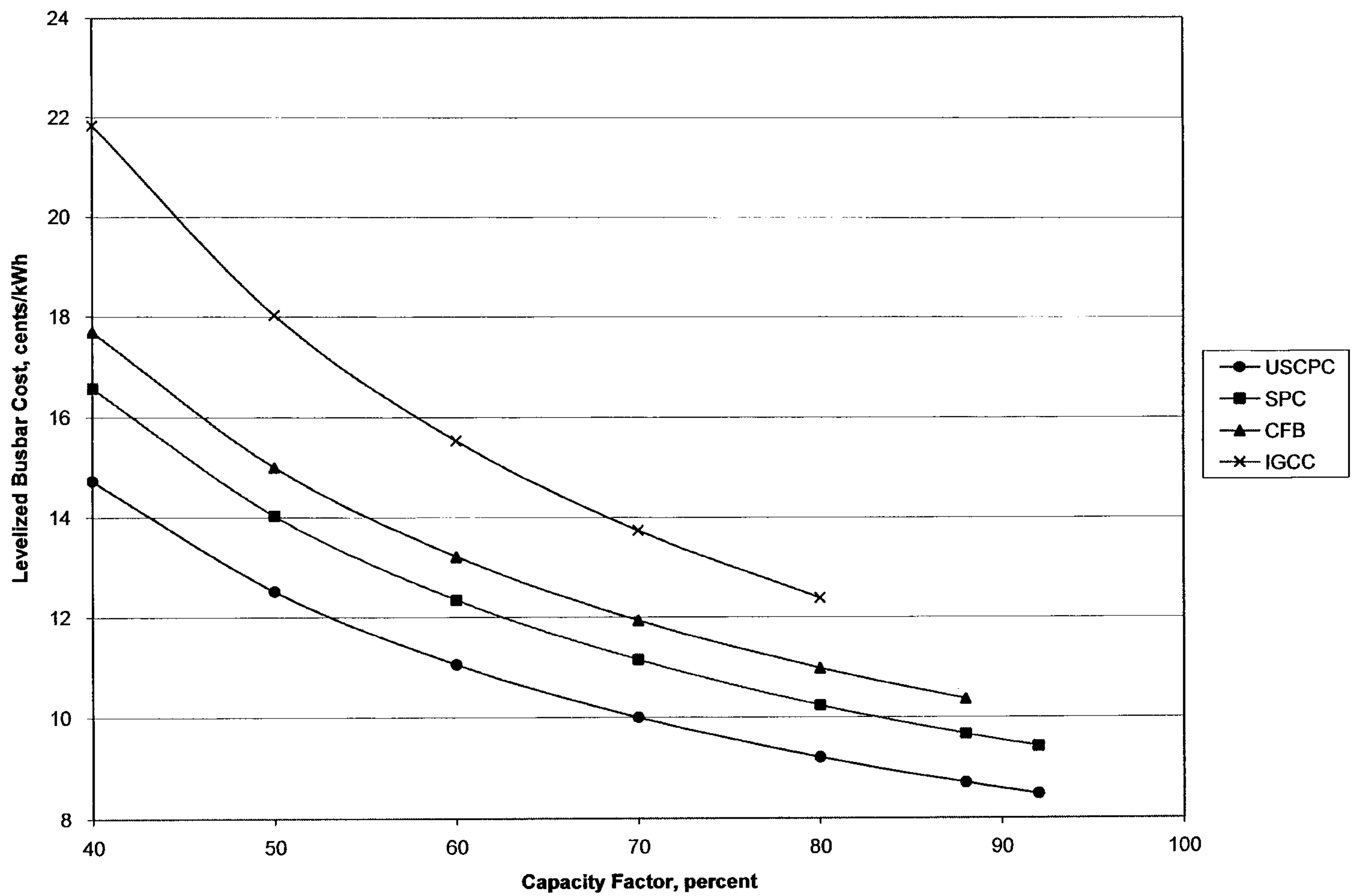

Figure 1-4. Busbar Cost Variation with Capacity Factor

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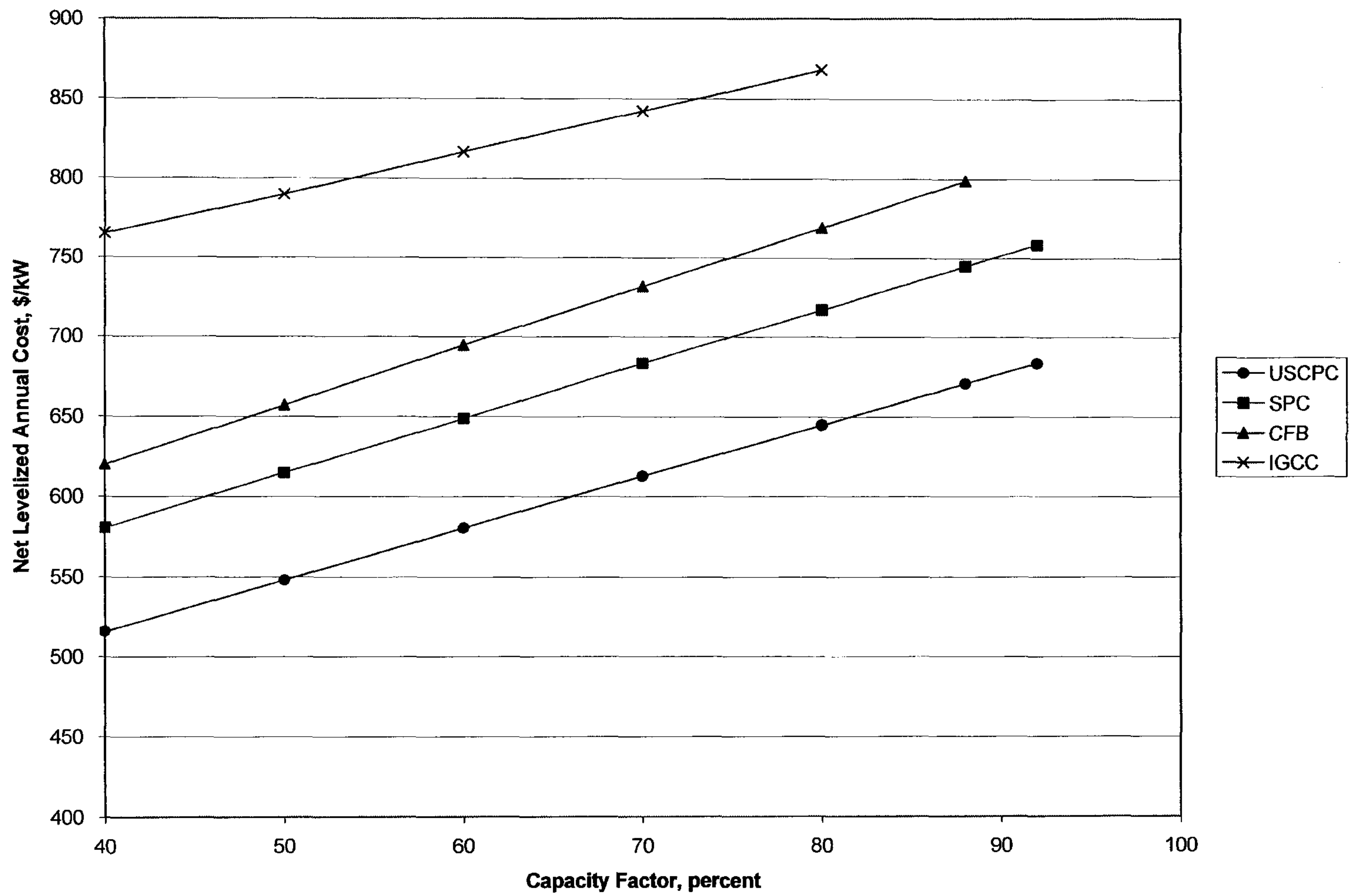

Figure 1-5. Net Levelized Annual Cost Variation with Capacity Factor

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1.7 Conclusions

This study made a comparison of performance and cost of four commercially available coal-fired power generation technologies. These were USCPC, SPC, CFB and IGCC. The estimates for performance were made using publicly available data and engineering data that has been collected by Black & Veatch and FPL. The results of the study are not intended to be absolute for any given technology but rather are intended to be accurate relative from one technology to another.

This study addresses technology risks known or assumed for each type of plant. Clearly PC plants are commercial and have been a dependable generation technology for years. The advancement of operation at ultrasupercritical steam conditions is somewhat new, but has been commercially demonstrated and proven around the world. CFB has also proven its dependability over the past two decades and is considered a mature technology. IGCC has been demonstrated on a commercial scale for over ten years. A second round of commercial scale IGCC plants is being planned currently. Many utilities will reserve decisions on making future IGCC installations until they have observed the installation and operation of these new plants.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry.

Based on the assumptions, conditions, and engineering estimates made in this study, the USCPC option is the preferred technology selection for the addition of a nominal 2,000 MW net output at the Glades site. The busbar cost of the SPC case, which is the second lowest busbar cost case, is nearly 10 percent more than USCPC. USCPC will have good environmental performance because of its high efficiency. Emissions of NO_x and PM will be very similar across all technologies. Sulfur emissions would be slightly lower for IGCC than the PC and CFB options, although start-up and shutdown flaring will reduce the potential benefit of IGCC. The lower expected reliability of IGCC, particularly in the first years of operation, could compromise FPL's ability to meet the baseload generation requirement and require FPL to run existing units at higher capacity factors.

For the 2012 to 2014 planning time period, USCPC will be the best technical and economic choice for installation of 2,000 MW of capacity at the Glades site.

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2.0 Introduction

This study is in connection with Florida Power & Light's (FPL) generation expansion project investigations for the addition of a nominal 2,000 MW of capacity. The objective of this technology assessment is to characterize the commercially available coal fired electric power generation technologies. The baseload coal technologies considered were SPC, USCPC, CFB, and IGCC. These options were selected as representative of the options that could meet FPL's clean coal capacity planning needs.

This study provides technology descriptions, plant descriptions and assumptions, and screening level estimates of performance, capital costs, and O&M costs for four coal power generation technologies. Full-load performance estimates were developed at both the hot day and average day ambient conditions.

Each of the cases considered would be located on a greenfield site at the proposed Florida Glades Power Park (FGPP) in Moore Haven, Florida. The required net capacity would be met by installing blocks of power to obtain a nominal 2,000 MW net at the plant boundary. The SPC unit would have a net capacity of 500 MW. The SPC units would be arranged in a four boiler-by-four steam turbine (4x4) configuration. This configuration would produce the required net capacity of 2,000 MW. Each SPC unit would have a net capacity of 980 MW; a 2x2 configuration would be used. Each CFB unit would have a 500 MW net capacity and would comprise two 250 MW CFB boilers and one 500 MW steam turbine. An 8x4 configuration would be required for the CFB case.

For the IGCC case, the nominal 2,000 MW project net capacity could be met by two 940 MW IGCC units. To obtain the 1,880 MW net capacity at the site boundary, six GE Radiant gasifiers would be used in two 3x3x3x1 configurations. The combined cycle configuration of the FGPP plant would consist of six combustion turbine generators (CTGs) whose exhaust heat would generate steam in six heat recovery steam generators (HRSGs). Steam produced in the HRSGs would then be expanded through two steam turbine generators (STGs).

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Each of the technologies considered would be fired by a blended fuel consisting of Central Appalachian coal, Colombian coal, and petcoke. A summarized list of the cases that were considered is shown in Table 2-1.

Table 2-1. Summary of Power Generation Technologies

Case	Technology Type	Single Unit Output, MW	Net Plant Output, MW	Configuration	Fuel Supply
1	SPC	500	2,000	4 Boilers 4 STGs	AQCS Blend
2	USCPC	980	1,960	2 Boilers 2 STGs	AQCS Blend
3	CFB	500	2,000	8 Boilers 4 STGs	AQCS Blend
4	IGCC	940	1,880	6 GE Gasifiers 6 CTGs 6 HRSGs 2 STGs	IGCC Blend

Assumptions were made for each technology, which addressed their configuration and AQCS. The AQCS for each technology were selected to comply with NSPS and recent BACT levels for criteria pollutants, including oxides of nitrogen (NO_x), sulfur dioxide (SO_2), filterable particulate matter of 10 microns or less (PM_{10}), and sulfuric acid mist (SAM). AQCS assumptions were made by FPL and are expected to be appropriate to control air emissions to the levels specified in Table 5-4.

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3.0 PC and CFB Technologies

This section contains a summary-level comparison of PC and CFB technologies, including review of technology experience in the United States and discussions of advanced PC steam conditions and issues related to scaling-up CFB unit sizes.

The function of a steam generator is to provide controlled release of heat from the fuel and efficient transfer of heat to the feedwater and steam. The transfer of heat produces main steam at the pressure and temperature required by the high-pressure (HP) turbine. Coal fired steam generator design has evolved into two basic combustion and heat transfer technologies. Suspension firing of coal in a PC unit and the combustion of crushed coal in a CFB unit are the predominant coal fired technologies in operation today.

3.1 Pulverized Coal

Coal is the most widely used fuel for the production of power, and most coal-burning power plants use PC boilers. PC units utilize a proven technology with a very high reliability level. These units have the advantage of being able to accommodate up to 1,300 MW, and the economies of scale can result in low busbar costs. PC units are relatively easy to operate and maintain.

New-generation PC boilers can be designed for supercritical steam pressures of 3,500 to 4,500 psia, compared to the steam pressure of 2,400 psia for conventional subcritical boilers. The increase in pressure from subcritical (2,400 psia) to supercritical (3,500 psia) generally improves the net plant heat rate by about 200 Btu/kWh (HHV), assuming the same main and reheat steam temperatures and the same cycle configuration. This increase in efficiency comes at a cost, however, and the economics of the decision between subcritical and supercritical design depend on the cost of fuel, expected capacity factor of the unit, environmental factors, and the cost of capital.

Newly constructed supercritical PC boilers are currently being designed to provide main and reheat steam at 1,050° F or higher. Advancements in metal alloys now allow main steam temperatures of 1,112° F and reheat temperatures of 1,148° F. The US DOE has defined ultra-supercritical steam cycles as operating pressures exceeding 3,600 psia and main superheat steam temperatures approaching 1,100° F[1].

[1] "Materials Development for Ultra-supercritical Boilers", US Department of Energy, Clean Coal Today, Fall 2005

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To date, several ultrasupercritical projects in the US, Europe and Japan have been completed or are soon to be completed. Table 3-1 lists some of the more notable projects that have pushed supercritical PC technology to higher throttle pressures and temperatures.

For this study, FPL is investigating USCPC as a potential candidate for electric power generation capacity at FGPP. Although use of USCPC will be a technology advancement in the US, based on documented success of this technology in Europe and Japan shows that USCPC is not a significant technology risk for FPL.

Beyond what is feasible with current technology, future advancements in the use of high-nickel alloys could allow main steam temperatures to reach 1,292° F with a reheat temperature of 1,328° F; however this technology has not yet been fully developed or tested. The THERMIE 700 project in Europe is the first attempt at these higher steam temperatures. Construction of this plant was originally planned for 2008 with a commercial operation being achieved in 2012; however the progress of this project has appeared to stall. The newer alloyed materials necessary to build a plant of this type would not be commercially available until sometime after the successful operation of the THERMIE 700 or a similar demonstration project. In addition to the boiler improvements that would be necessary to increase steam temperatures, advancements in the steam turbine sector would have to be made in order to reliably sustain higher temperatures. The International Energy Agency's Clean Coal Centre published the history and the possible future of steam temperatures and pressures as shown on Figure 3-1.

Similar to increasing the steam temperature, an increase in steam pressure will also increase efficiency and capital cost. However, the efficiency gain for increased steam pressure is not as great as that for increased temperature. The economics of each situation would have to be examined to optimize the design temperatures and pressure.

With PC technology, coal that is sized to roughly ¾-in. top size is fed to the pulverizers which finely grind the coal to a size of no less than 70 percent (of the coal) through a 200 mesh screen (70 microns). This pulverized coal, suspended in the primary air stream, is conveyed to coal burners. At the burner, this mixture of primary air and coal is further mixed with secondary air and, with the presence of sufficient heat for ignition, the coal burns in suspension with the expectation that combustion will be complete before the burner flame contacts the back wall or sidewalls of the furnace. Current pulverized fuel combustion technology also includes features to minimize unwanted products of combustion. Low NO_x burners or air and fuel staging can be used to reduce NO_x and carefully controlling air-fuel ratios can reduce CO emissions.

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Table 3-1. Notable Worldwide Ultrasupercritical Projects						
			Steam Conditions			
Power Plant Name (Owner)	Country	MW	Steam Pressure, psia	Main Steam, ° F	Reheat Steam, ° F	COD
Big Stone 2 (Multiple)	USA	600	3,600	1,080	1,080	2012
Comanche 3 (Xcel)	USA	750	3,800	1,055	1,055	2009
Council Bluffs 4(Mid American)	USA	790	3,690	1,050	1,075	2007
Elm Road 1 & 2 (WE Energies)	USA	2x600	3,800	1,055	1,055	2009
Genesee 3 (EPCOR)	Canada	495	3,626	1058	1054	2005
Holcomb 2 (Sunflower)	USA	700	3,600	1,080	1,080	2011
Holcomb 3 (Sunflower)	USA	700	3,600	1,080	1,080	2012
Holcomb 4 (Sunflower)	USA	700	3,600	1,080	1,080	2013
Iatan 2 (KCP&L)	USA	850	3,686	1,085	1,085	2010
North Rhine-Westphalia Reference Power Plant – 60 Hz	USA	800	4,134	1,112	1,030	2010
Trimble County (LG&E)	USA	750	3,750	1,088	1,088	2010
Red Rock (AEP)	USA	900	4,000	1,100	1,100	2012
Hempstead (AEP)	USA	650	4,000	1,100	1,100	2011
Weston 4 (WPSC)	USA	500	3,800	1,076	1,076	2007
Boa 2 Neurath	Germany	2x1,000	3,771	1,103	1,103	2010
Boxberg 1	Germany	907	3,860	1,013	1,078	2000
Lippendorf	Germany	934	3,873	1,029	1,081	1999
Niederaussem	Germany	1,027	3,989	1,076	1,112	2003
North Rhine-Westphalia Reference Power Plant – 50 Hz	Germany	600	4,134	1,112	1,148	2008
Hemweg 8	Netherlands	680	3,844	1,004	1,054	1994
Avedoere 2	Denmark	450	4,351	1,076	1,112	2002
Nordjylland 3	Denmark	411	4,206	1,080	1,076	1998
Isogo 1	Japan	600	4,061	1,121	1,135	2002
Hitachi Naka, Tokyo Electric Power	Japan	1,000	3,675	1,112	1,112	2003

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Table 3-1. Notable Worldwide Ultrasupercritical Projects

Power Plant Name (Owner)	Country	MW	Steam Conditions			COD
			Steam Pressure, psia	Main Steam, ° F	Reheat Steam, ° F	
Hranomachi 2, Tohoku Electric Power	Japan	1,000	3,675	1,112	1,112	1998
Tachibanawan 1	Japan	1,050	3,750	1,121	1,135	2000
Changshu	China	3x600	3,684	1,009	1,060	2006
Chugoku EPCO Misumi 1	China	1,000	3,556	1,112	1,112	1998
Huaneng	China	4 x 1,000	3,844	1,112	1,112	2008
Waigaoqiao	China	2 x 900	4,047	1,008	1,044	2004
Wangqu	China	2 x 600	3,989	1,060	1,056	2007
Zouxian IV	China	2 x 1,000	3,916	1,112	1,112	2008

COD--Commercial Operation Date

Note:

Data reported from various sources, not all data can be verified.

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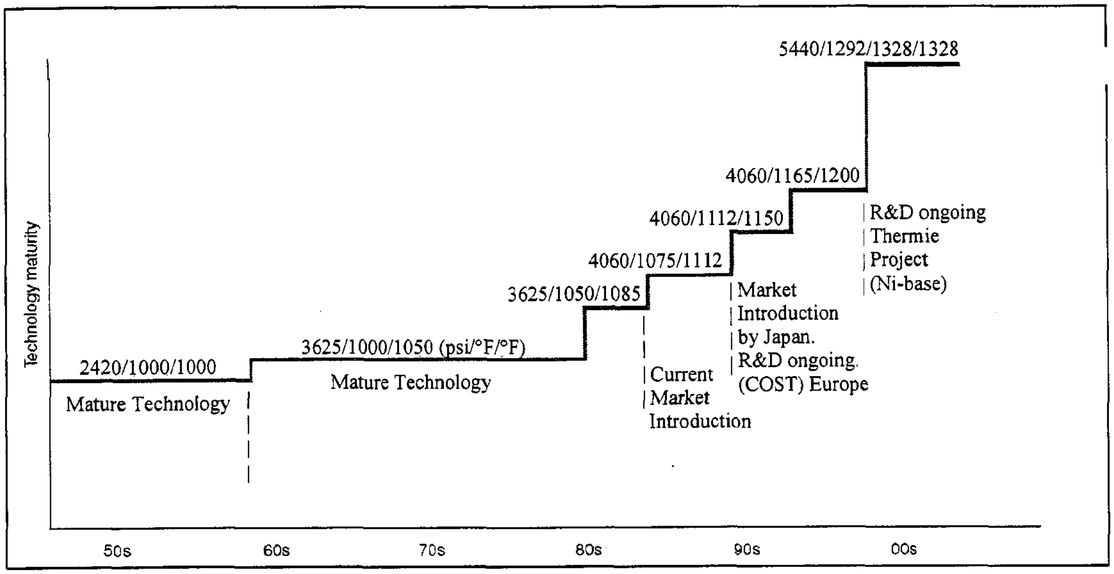

Figure 3-1. Trends in Steam Conditions of Coal-Fired Power Plants[1]

Because of the high combustion temperature of PC at the burners, the furnace enclosure is constructed of membrane waterwalls to absorb the radiant heat of combustion. This heat absorption in the furnace is used to evaporate the preheated boiler feedwater that is circulated through the membrane furnace walls. The steam from the evaporated feedwater is separated from the liquid feedwater and routed to additional heat transfer surfaces in the steam generator. Once the products of coal combustion (ash and flue gas) have been cooled sufficiently by the waterwall surfaces so that the ash is no longer molten but in solid form, heat transfer surfaces, predominantly of the convective type, absorb the remaining heat of combustion. These convective heat transfer surfaces include the superheaters, reheaters, and economizers located within the steam generator enclosure downstream of the furnace. The final section of boiler heat recovery is in the air preheater, where the flue gas leaving the economizer surface is further cooled by regenerative or recuperative heat transfer to the incoming combustion air.

Though the steam generating surfaces are designed to preclude the deposition of molten or sticky ash products, on-line cleaning systems are provided to enable removal of ash deposits as they occur. These on-line cleaners are typically soot blowers that utilize either high-pressure steam or air to dislodge ash deposits from heat transfer surfaces or,

[1] "Profiles", IEA Clean Coal Centre, November 2002. Available at:
http://www.iea-coal.org.uk/publishor/system/component_view.asp?PhyDocId=5385&LogDocId=81049

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in cases with extreme ash deposition, utilize high-pressure water cannons to remove molten ash deposits from evaporative steam generator surfaces. The characteristics of the coal, such as ash content and ash chemical composition, dictate the type, quantity, and frequency of use of these on-line ash cleaning systems. Ash characteristics also dictate steam generator design regarding the maximum flue gas temperatures that can be tolerated entering convective heat transfer surfaces. The design must ensure that ash in the flue gas stream has been sufficiently cooled so it will not rapidly agglomerate or bond to convective heat transfer surfaces. In the case of very hard and erosive ash components, the flue gas velocities must be sufficiently slow so that the ash will not rapidly erode heat transfer surfaces.

With PC combustion technology, the majority of the solid ash components in the coal will be carried in the flue gas stream all the way through the furnace and convective heat transfer components to enable collection with particulate removal equipment downstream of the air preheaters. Typically, no less than 80 percent of the total ash will be carried out of the steam generator for collection downstream. Roughly 15 percent of the total fuel ash is collected wet from the furnace as bottom ash, and 5 percent is collected dry in hoppers located below the steam generator economizer and regenerative air heaters.

3.2 PC Vendors

There are currently eight major manufacturers of PC steam generators. These manufacturers are listed in Table 3-2.

Table 3-2. PC Boiler Vendors

• Alstom	• Foster Wheeler (FW)
• Babcock Power (BP)	• Ishikawajima Harima Heavy Industries (IHI)
• Babcock & Wilcox (B&W)	• Mitsubishi Heavy Industries (MHI)
• Babcock-Hitachi (B-H)	• Mitsui Babcock (MB)

The current utility steam generator technology offered by the major vendors is similar, with the exception of boiler tube construction, commercially available alloys, and burner arrangement and technology.

3.2.1 Boiler Tube Construction

All subcritical boilers use vertical tubes; nearly all of the vendors use smooth tubes except Babcock & Wilcox which uses a slightly rifled tube. There are two main

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design philosophies for supercritical boiler tube design. Either a vertical rifled or spiral wound tube is used. The two designs are shown on Figure 3-2.

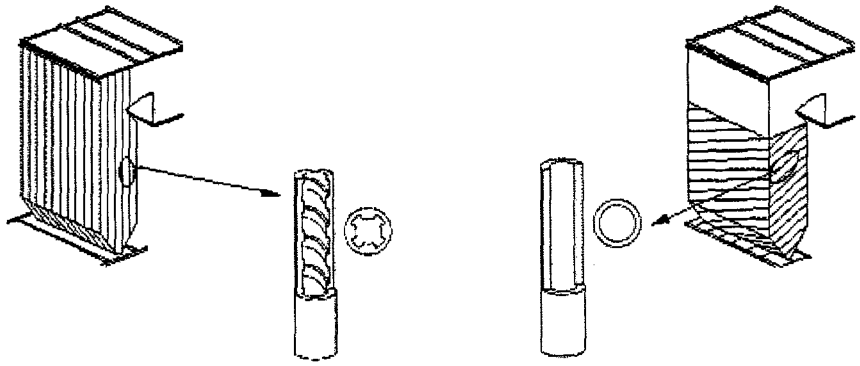

Figure 3-2. Vertical Rifled and Smooth Spiral Wound Tube Design (MHI).

There are numerous advantages and disadvantages to both the vertical and spiral tube designs. The vertical tube from a design standpoint is considered to be more ideal, however in practice the spiral tube design is the accepted technology. By nature in a rectangular boiler different sections of the furnace wall will see different temperatures. This can cause problems in a vertical tube arrangement where the feedwater cannot travel vertically. Certain sections of the wall will receive excess heating which can cause failure while others will be exposed to less heat. In a spiral wound design where the tube wraps around the furnace wall each tube will be exposed to the same amount of heat and this problem is avoided.

Thus current boiler designs implement the spiral tube design in the lower furnace and then switch to the vertical tube design in the upper furnace where the heat flux is lower. The disadvantage of the spiral tube design is that there is a much larger pressure drop through the tube compared to the vertical tube design. This pressure drop increases the work the feedwater pump must perform, thus lowering the overall efficiency of the plant. The capital costs associated with a vertical tube furnace are also lower, because the design requires a much simpler construction with less supporting structures. Because of the savings that could be experienced by using a vertical tube design, work is being performed to try and overcome the challenges faced by the vertical tube design.

The most prominent challenge of implementing a vertical tube design is its inability to handle the high heat flux in the lower furnace. As shown on Figure 3-2, one of the recent developments to aid with this issue is to use ribs within the tube instead of a smooth wall. This increases heat transfer area and creates turbulence within the tube, which increases overall heat transfer rates to the water and keeps the tubes cooler.

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A possible advantage of a vertical tube design is its ability to operate in natural circulation. Current supercritical boiler tube designs rely on forced circulation systems. New vertical tube designs are currently being developed to operate in natural circulation. A characteristic of natural circulation subcritical boilers is that when the water within the tube heats up the mass flow rate will also increase, thus drawing in more cooler water to maintain a safe tube temperature. In a supercritical application this characteristic would automatically control problems associated with boiler tubes overheating. However this characteristic has only been shown to occur in laboratory tests and there is no actual experience with a supercritical power plant using this technology.

Table 3-3 highlights the advantages and disadvantages of vertical rifled tubes versus spiral wound tubes.

Table 3-3. Vertical Rifled Tubes vs. Spiral Wound Tubes

Vertical Rifled Tubes	Spiral Wound Tubes
Lower Capital Costs • Simpler Construction • Self Supporting Tubes	Higher Capital Costs • More Complex Construction
Lower Operating Costs • Lower Pressure Drop • Less Feedwater Pumping Required	Higher Operating Costs • Higher Pressure Drop • More Feedwater Pumping Required
Can Operate in Natural Circulation	Forced Circulation Operation Only
Less Operating History	Proven Technology

3.2.2 Commercially Available Alloys

In addition to the type of boiler tube, selecting the tube material is a major design decision. There are currently a number of steel alloys available for use in boiler tube construction. Table 3-4 displays some of the more common alloying elements and the properties they exhibit. While Table 3-4 describes the general characteristics of alloying elements, metallurgy is a complicated science, and small variations in the combination of elements at different heating temperatures can produce varying results.

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Table 3-4. Common Alloying Elements

Alloying Element	Properties
Chromium	Increases high temperature strength, adds resistance to corrosion and oxidation
Nickel	Increases hardenability and impact strength
Chromium – Nickel	Tends to add the positive properties of each element without the negative aspects
Molybdenum	Increases hardenability and creep strength
Vanadium	Increases yield and tensile strength

The common steel alloys are primarily differentiated by their cost, strength, and temperature properties. Capital costs associated with the alloy increase with increased temperature resistance and increased strength. Using an alloy that can withstand higher temperatures allows for higher steam temperatures. Higher steam temperatures directly correlate to increased boiler efficiencies. The higher capital cost of the alloy can be offset by this increase in boiler efficiency. Table 3-5 lists some of the common alloys and their associated pressure/temperature operating limits for boiler applications.

Another benefit is the increased strength properties of the alloyed steels. By using a stronger alloy, a smaller pipe diameter and thickness can be used. This results in significant weight savings in the boiler. A lighter boiler requires less structural support and this lowers the material cost during construction of pipe supports, structural steel, and equipment connection loads. Smaller component thickness allows for more operating flexibility as well. A plant with large thick sections will be limited to the ramp rates it can safely achieve. Replacing thick sections with thin sections allows for quicker heat transfer from inside the furnace to the feedwater or steam, this allows for larger ramp rates and better load matching capability.

The following is a discussion of the current commercially available alloys and their respective applications.

3.2.2.1 Boiler Tubes

P22, P91, and P92 are some of the most commonly used steel alloys. These steels are primarily alloyed with chromium (P22 - 2.25 percent chromium, P91 and P92 – 9 percent chromium) and also contain smaller amounts of molybdenum. P91 is now used in favor of P22, because of the higher temperatures and pressures it can handle. P92 is similar to P91, but it contains up to 2 percent tungsten in addition the chromium and molybdenum present in P91. P92 is used in installations where it will be exposed to temperatures higher than what P91 can withstand.

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Table 3-5. Coal-Fired Power Generation Boiler Temperature and Material Development				
Live Steam		Application Date	Alloy	Equivalent Material
Pressure, psi	Temperature, ° F			
<2,900	<968	Since the early 1960s	X20	Cr Mo V 11 1
<3,626	<1,004	Since the early 1980s	P22	2 ¼ Cr Mo
<4,351	<1,040	Since the late 1980s	P91	9Cr - 1Mo
<4,786	<1,148	Since 2004	P92	X10CrWMoVNb9-1, Europe STBA29-STPA29, Japan
<5,076	<1,292	Expected in 2010	Super Alloys	CCA 617 - IN 740 Haynes 230 - Save 12
Source: M.R. Susta and K. George, "Ultra-Supercritical Pulverized Coal Fired Power Plants," CoalGen 2006, Cincinnati, OH, August 16-18, 2006				

3.2.2.2 Superheater Tubes

Superheater tubes have been previously constructed out of materials such as T20 or X20, but due to poor corrosion resistance austenitic steels are now more commonly used. Suitable materials for applications up to 1,050° F are the austenitic steels T316 and T346[1]. NF709 and HRC3 are considered suitable for applications of up to 1,112° F main steam temperature.

[1] "Supercritical Steam Cycles for Power Generation Applications," Department of Trade and Industry, January 1999.

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3.2.2.3 Headers, Manifolds, Piping

For lower steam temperatures of 1,050° F carbon steel X20CrMoV121 can be used. To achieve higher steam temperatures P91/T91/F91 should be used[1]. For 1,112° F main steam temperature applications ferritic steels P92, P122 and the austenitic steel X3CrNiMoM1713 are considered to be the suitable commercially available options.

In the future advancements in nickel alloys could allow for main steam temperatures of 1,292° F.

Figure 3-3 is a chart presented by Alstom, a major boiler manufacturer, showing their recommended boiler alloys for particular steam conditions. Alstom has included a timeline showing expected availabilities of nickel alloy materials.

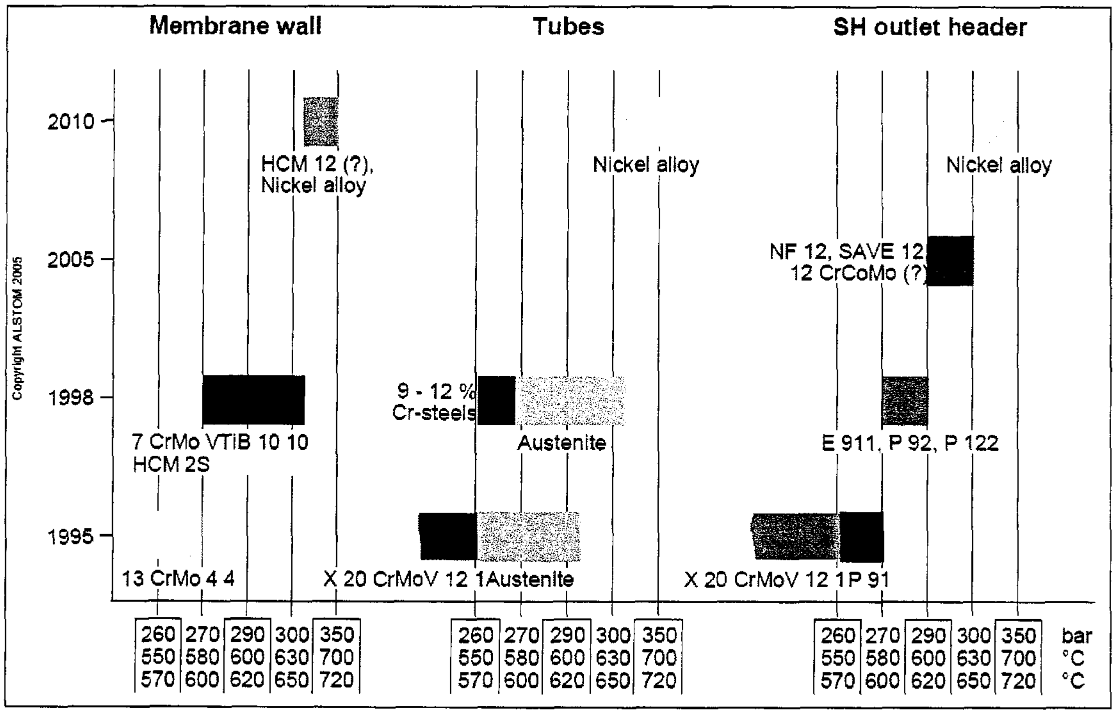

Figure 3-3. Alstom Boiler Alloys and Steam Conditions

Determining which alloy to use depends on the particular application. In some cases the increased capital cost can be offset by increased boiler efficiency, lower emissions, and lower structural cost. The most common practice for alloy selection is to first determine the surface temperature of the boiler tubes from the boiler design and then select an alloy that can withstand that temperature.

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3.2.3 Burner Arrangement

PC boiler burners can be arranged in either a wall-fired or a corner or tangentially fired set-up. The wall-fired burners are either rear or front wall firing or they can be set up as front and rear-wall opposed. Corner or tangential fired set-ups typically have the burners firing from each of the four corners of the furnace.

3.3 Fluidized Bed

During the 1980s, fluidized bed combustion (FBC) rapidly emerged as a viable alternative to PC-fueled units for the combustion of solid fuels. Initially used in the chemical and process industries, FBC was applied to the electric utility industry because of its perceived advantages over competing combustion technologies. SO_2 emissions could be controlled from FBC units without the use of external scrubbers, and NO_x emissions from FBC units are inherently low. Furthermore, FBC units are "fuel flexible," with the capability to fire a wide range of solid fuels with varying heating values, ash contents, and moisture contents. Additionally, slagging and fouling tendencies were minimized in FBC units because of the low combustion temperatures.

There are several types of fluidized bed technologies, as illustrated on Figure 3-4. Pressurized FBC is currently a demonstration technology and will not be discussed here. Atmospheric FBC (AFBC) is generally divided into two categories: bubbling and circulating. A typical AFBC is composed of fuel and bed material contained within a refractory-lined, heat absorbing vessel. The composition of the bed during full-load operation is typically in the range of 98 percent bed material and only 2 percent fuel. The bed becomes fluidized when air or other gas flows upward at a velocity sufficient to expand the bed. At low fluidizing velocities (3 to 10 ft/sec), relatively high solid densities are maintained in the bed and only a small fraction of the solids are entrained from the bed. A fluid bed that is operated in this velocity range is referred to as a bubbling fluidized bed (BFB).

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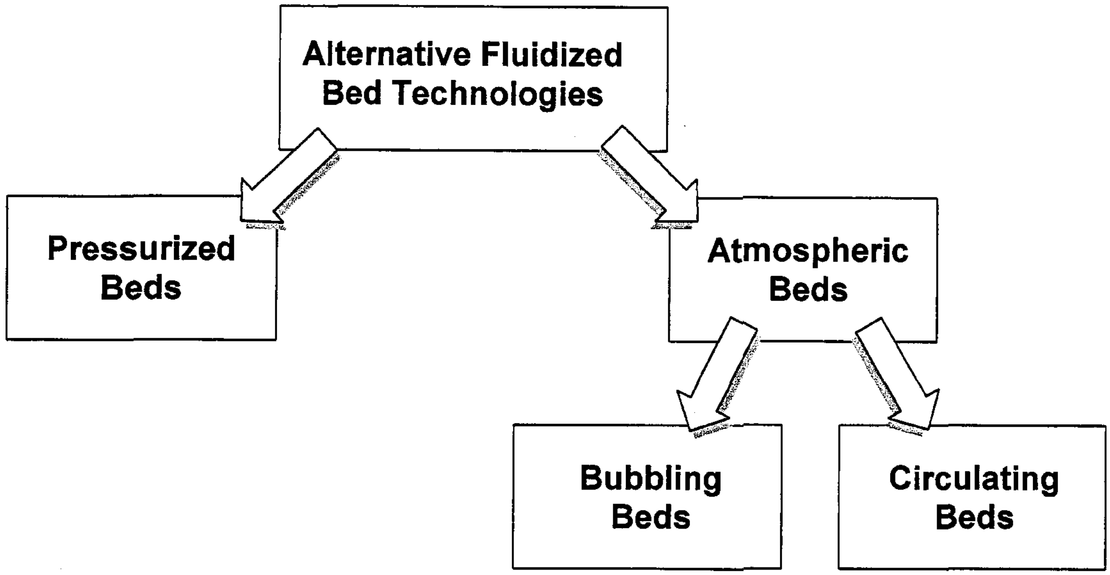

Figure 3-4. Fluidized Bed Technologies

If the fluidizing velocity is increased, smaller particles are entrained in the gas stream and transported out of the bed. The bed surface, well defined for a BFB combustor, becomes more diffuse; solids densities are reduced in the bed. A fluid bed that is operated at velocities in the range of 13 to 22 ft/sec is referred to as a circulating fluidized bed, or CFB. The CFB has better environmental characteristics and higher efficiency than BFB and is generally the AFBC technology of choice for fossil fuel applications greater than 50 MW.

The primary coal fired boiler alternative to a PC boiler is a CFB boiler. In a CFB unit, a portion of the combustion air is introduced through the bottom of the bed. The bed material normally consists of fuel, limestone (for sulfur capture), and ash. The bottom of the bed is supported by water-cooled membrane walls with specially designed air nozzles that uniformly distribute the air. The fuel and limestone are fed into the lower bed. In the presence of fluidizing air, the fuel and limestone quickly and uniformly mix under the turbulent environment and behave like a fluid. Carbon particles in the fuel are exposed to the combustion air. The balance of combustion air is introduced at the top of the lower, dense bed. Staged combustion and the low combustion temperature limit the formation of thermal NO_x.

The bed fluidizing air velocity is greater than the terminal velocity of most of the particles in the bed and, thus, fluidizing air carries the particles through the combustion chamber to the particulate separators at the furnace exit. The captured solids, including any unburned carbon and unused calcium oxide (CaO), are re-injected directly back into the combustion chamber without passing through an external recirculation. This internal

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solids circulation provides longer residence time for the fuel and limestone, resulting in good combustion and improved sulfur capture.

Commercial CFB units offer greater fuel diversity than PC units, operate at competitive efficiencies, and, when coupled with a polishing SO_2 scrubber, operate with emissions below the current levels mandated by federal standards. Compared to conventional PC technology, which was first utilized in the 1920s, CFB is a commercially proven technology that has been in reliable electric utility service in the United States for only the past 20 years.

By the late 1980s, the transition had been made from small industrial-sized CFB boilers to several operating electrical utility reheat boilers, ranging in size from 75 to 165 MW. Several reheat boilers of over 300 MW are currently in service, and boiler suppliers are offering boiler designs to provide steam generation sufficient to support up to 600 MW, but none has been built larger than 340 MW. Fuels for these applications range from petcoke and bituminous coal to high ash refuse from bituminous coal preparation and cleaning plants, and high moisture fuels such as lignite.

An environmentally attractive feature of CFB is that SO_2 can be removed during the combustion process by adding limestone to the fluid bed. The CaO formed from the calcination of limestone reacts with SO_2 to form calcium sulfate, which is removed from the flue gas with a conventional particulate removal device. The CFB combustion temperature is controlled at approximately 1,600° F, compared to approximately 2,500 to 3,000° F for conventional PC boilers. Combustion at the lower temperature has several benefits. First, the lower temperature minimizes the sorbent (typically limestone) requirement, because the required calcium to sulfur (Ca/S) molar ratio for a given SO_2 removal efficiency is minimized in this temperature range. Second, 1,550 to 1,600° F is well below the ash fusion temperatures of most fuels, so the fuel ash never reaches its softening or melting points. The slagging and fouling problems that are characteristic of PC units are significantly reduced, if not eliminated. Finally, the lower temperature reduces NO_x emissions by nearly eliminating thermal NO_x. Figure 3-5 illustrates the benefits of the lower combustion temperature for CFBs.

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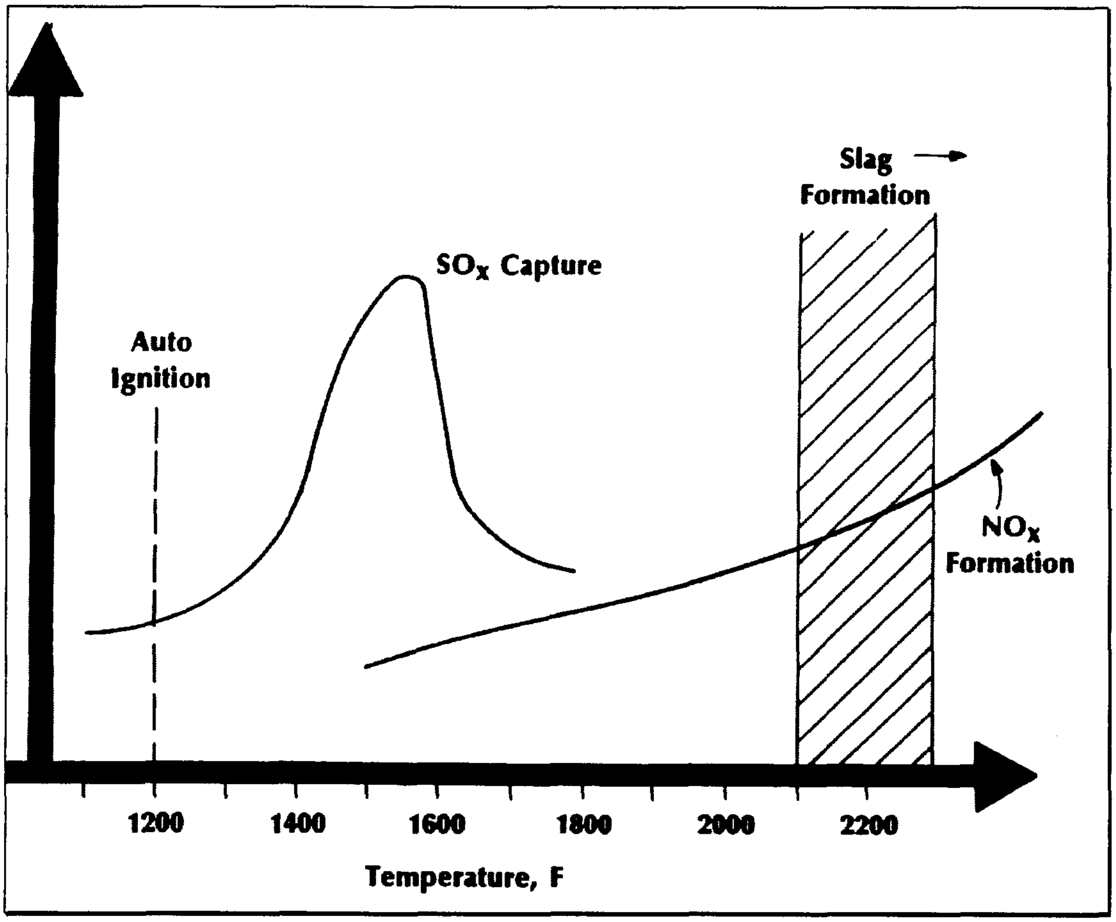

Figure 3-5. Environmental Benefits of CFB Technology

Since combustion temperatures are below ash fusion temperatures, the design of a CFB boiler is not as dependent on ash properties as is a conventional PC boiler. With proper design considerations, a CFB boiler can fire a wider range of fuels with less operating difficulty.

A typical CFB arrangement is illustrated schematically on Figure 3-6. In a CFB, primary air is introduced into the lower portion of the combustion chamber, where the heavy bed material is fluidized and retained. The upper portion of the combustor contains the less dense material that is entrained with the flue gas from the bed. Typically, secondary air is introduced at higher levels in the combustor to ensure complete combustion and to reduce NO_x emissions. The combustion gas generated in the combustor flows upward, with a considerable portion of the solids inventory entrained. These entrained solids are separated from the combustion gas in hot cyclone-type dust collectors or in mechanical particulate separators and are continuously returned to the combustion chamber by a recycle loop. The cyclone separator and recycle loop may

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include additional heat recovery surface to control the bed temperature and steam temperature and to minimize refractory requirements.

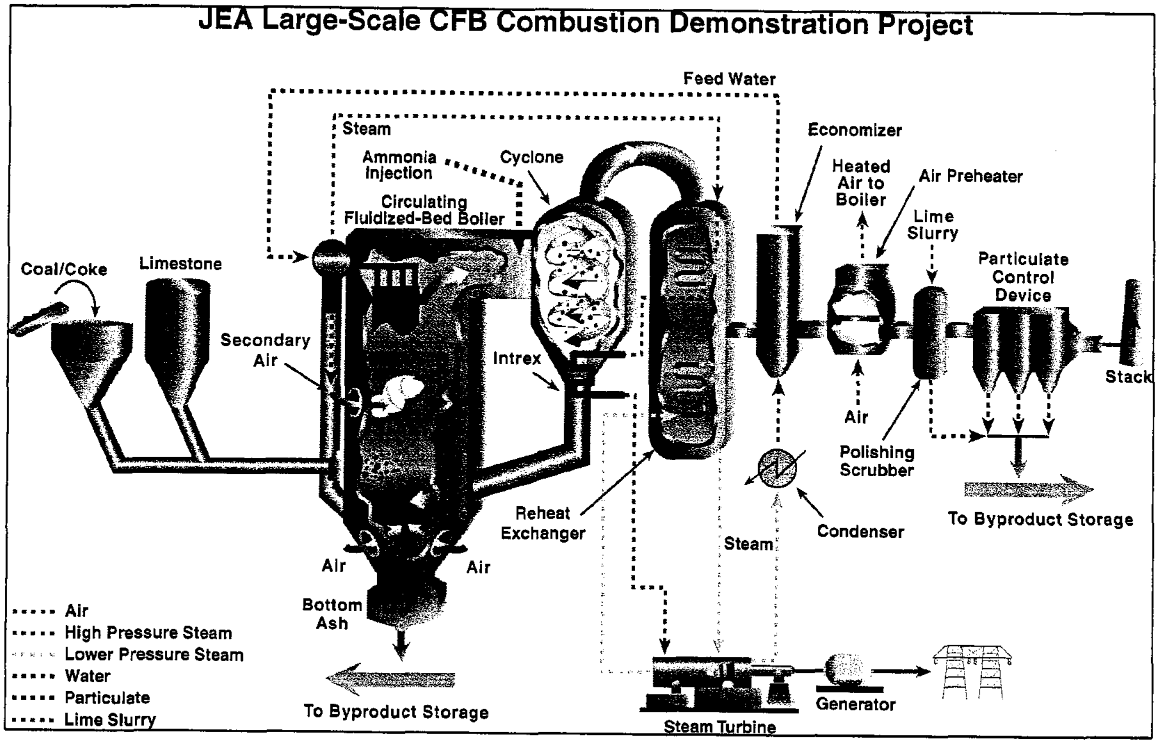

Figure 3-6. Typical CFB Unit

The combustion chamber of a CFB unit generally consists of membrane-type welded waterwalls that provide most of the evaporative boiler surface. Heat transfer to evaporative surfaces is primarily through convection and conduction from the bed material that contacts the evaporative wall surfaces or division panel surfaces located in the upper combustor. The lower third of the combustor is refractory lined to protect the waterwalls from erosion in the high-velocity dense bed region.

The fuel size for a CFB boiler is much coarser than the pulverized fuel needed for suspension firing in a PC boiler. Compared to the typical 70 micron particle size for a PC unit, the typical fuel size for a CFB is approximately 5,000 microns. Especially for high ash fuels, the use of larger fuel sizing reduces auxiliary power and pulverizer maintenance requirements and eliminates the high cost of pulverizer installation.

Ash removal from the CFB boiler is from the bottom of the combustor and also from fly ash that is entrained in the flue gas stream, similar to PC boilers. With a CFB boiler, the ash split between bottom ash and fly ash is roughly 50 percent bed ash and 50 percent fly ash. All of the ash drains from CFB boilers are typically retained in a dry

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condition without the need for water impounded hoppers or water submerged conveyors, typically utilized for PC boiler bottom ash collection and conveying.

3.4 Technical Characteristics of PC Versus CFB

The technical characteristics of the two competing boiler technologies were addressed in the previous section. Table 3-6 compares PC and CFB across several different parameters; these are summarized in the following subsections.

3.4.1 Environmental

Environmental impacts are categorized as flue gas emissions, solid waste production, and water consumption:

- **Flue Gas Emissions**--In the US, PC and CFB technologies will be required to meet similar emissions levels.
- **Solid Waste Production**--Solid waste production for the two technologies would be similar, except that the bottom ash from the PC boiler would be transported in a wetted condition because of the bottom ash collection technology, which includes either water impounded bottom ash hoppers or submerged conveyors below the furnace bottom. Bed ash extraction from a CFB is a dry process, where the ash is collected in a granular form and cooled with a combination of fluidizing cooling air and water jacketed screw coolers. The quantity of sorbent required for sulfur removal will affect the relative volume of solid waste.
- **Water Consumption**--Water consumption for the two technologies would be essentially identical for the boiler drum blowdown to maintain boiler water quality; however, when steam is used for soot blowing, the boiler water makeup requirements may be slightly higher because of the higher soot blowing steam demand of PC boiler technology.

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Table 3-6. PC Versus CFB Boiler Comparison

Evaluation Parameter	PC Boiler	CFB Boiler
Environmental		
NO_x	SCR	SNCR
SO_2	FGD	Limestone injection and polishing FGD
Particulate	Fabric filter	Fabric filter
Operational		
Auxiliary Power	Base	Slightly higher
Maintenance	Base	Slightly higher
Fuel Flexibility	Within design coals	Better
Startup and Load Ramping	Base, 5 percent per minute	4 hours additional startup time, 2 to 3 percent per minute
Availability and Reliability	Base	Same
Technology Maturity	Well established	Recently constructed in 300 MW size
Capital Costs	Base	Slightly higher
Fixed O&M Costs	Base	Slightly higher
Variable O&M (Nonfuel) Costs	Base	Typically, slightly higher
Net Plant Heat Rate	Base	Higher

SCR--Selective Catalytic Reduction
FGD--Flue Gas Desulfurization
SNCR--Selective Non-catalytic Reduction

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3.4.2 Operational

Operational impacts are categorized as auxiliary power, maintenance, fuel flexibility, startup, and load ramping:

- **Auxiliary Power**--The power requirements of the primary air fans for the CFB boiler provide the motive power to fluidize and circulate the bed material. This is a higher power requirement than that of the primary air fans for a PC boiler application. Since CFB boilers do not need pulverizers, the power savings from this normally results in the auxiliary power requirements for the two boiler technologies being relatively similar, with CFB requirements being slightly higher.
- **Maintenance**--The major maintenance requirements of CFB boilers involve the refractory repairs caused by the erosive effects of the bed materials circulating through the boiler components. Initial CFB boiler applications experienced significant refractory maintenance requirements. Subsequent refractory system improvements, materials, and installation techniques have provided significant reductions in these maintenance requirements. The major maintenance requirements of PC boilers and their auxiliaries are often associated with pulverizers, soot blowers, and associated heat transfer surface damage caused by soot blower erosion in areas where excessive soot blowing is needed to prevent the accumulation of agglomerating ash deposits. Unlike PC boilers, CFB boilers do not require pulverizers. In addition, CFB boilers require fewer soot blowers because the coal ash temperature is not elevated to the point where it becomes molten or agglomerating. The O&M cost of PC is slightly less than that of CFB.
- **Fuel Flexibility**--CFB boilers have the capability of superior fuel flexibility compared to PC boilers. Since the combustion temperature of CFB boilers is below the ash initial deformation temperature, the slagging and fouling characteristics of alternative fuels are not of concern. As long as the CFB boiler auxiliaries, such as fuel feed equipment and ash removal equipment, are provided with sufficient capacity, a wide range of fuel heating values and ash content can be utilized. The capacity of the sorbent feed equipment also needs to be designed for the range of fuel sulfur content that is expected to occur. Because of the long fuel residence time in the CFB boiler combustion loop, a very wide range of fuel volatile matter content can also be utilized. A CFB boiler can efficiently burn fuels in ranges of volatility well below those required in a PC boiler.

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- **Startup**--Because of the large mass of bed material and larger quantity of refractory in a CFB boiler compared to a PC boiler, CFB boilers are somewhat less suited for numerous startups and cycling service than are PC boilers. The large mass of bed material results in significantly higher thermal inertia for a CFB boiler compared to a PC boiler. Startup from cold conditions can be extended for several hours. This higher thermal inertia can also result in unstable bed performance during periods of rapid load changes. Optimal sorbent feed for FGD is achieved during baseload operation, which enables consistent bed inventory, desulfurization, and sorbent utilization. CFB boilers have some advantages during hot and warm restarts, because the refractory and bed hold a significant amount of heat.
- **Load Ramping**--CFB boilers are generally capable of ramp rates of 2 to 3 percent per minute, but may be restricted to 1 to 2 percent per minute to control steam conditions, SO_2 emissions, and limestone stoichiometry fluctuations. PC boilers are generally capable of ramp rates of 5 percent per minute.

3.4.3 Availability and Reliability

Over the past 20 years that CFB boilers have been utilized for steam production for electric power generation, the availability and reliability have improved and are considered to be generally equivalent to PC boilers. Several improvements in refractory system designs, fuel and sorbent feed system designs, and ash extraction equipment design have been made that adequately address the initial problems encountered with these system components. These systems are high maintenance and can cause lower overall availability of CFB compared to PC. Since CFB boiler systems do not have pulverizers, do not have multiple burner systems with a large number of moving or controlled components, and have significantly fewer soot blowers, many of the high maintenance components of PC boilers are avoided.

3.4.4 Technology Maturity

Though CFB boilers have been used to provide steam for reheat turbine electric power generation for more than 20 years, the steaming capacities have been limited to less than 150 MW in most cases. In recent years, manufacturers have increased unit size to the point where there are more reheat boilers in service supporting electrical generation up to 300 MW gross output, with the largest being 320 MW net. These units are currently in service or under construction and are designed to burn the full range of solid fuels including low volatile anthracite, petcoke, subbituminous coal, high volatile

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bituminous coal, and high moisture lignite. CFB boiler manufacturers are currently proposing to supply units with capacities in excess of 400 MW electrical output. PC boilers have been installed and are operating with steaming capacities sufficient to support up to 1,300 MW of electrical generation. Because of the economies of scale for PC boiler and their auxiliaries, recent PC boiler installations have been predominantly larger than 250 MW. Many of the newer units have been designed to operate with supercritical steam pressure conditions.

3.5 FBC Experience in the United States

The first utility-grade AFBC unit was constructed in Rivesville, West Virginia, in 1976, a 30 MW (electric) Foster Wheeler BFB unit. One of the first utility-grade CFB units was the Tri-State Nucla project, completed in 1987. This 110 MW unit from Foster Wheeler was a Department of Energy (DOE) Clean Coal Demonstration Project. In the late 1980s and early to mid-1990s, a significant number of CFB units came online. In the early 1990s, the industry began to view CFB as a mature technology. The initial US CFB units were predominantly fired on bituminous coals. Around 1995, the trend reversed and almost all CFB units since that time have fired waste coals, lignites, or opportunity fuels such as petcoke and biomass. The field of international CFB vendors has consolidated to four dominating players: Alstom, Foster Wheeler, Lurgi, and Kvaerner Pulping. Alstom and Foster Wheeler have dominated the US and international markets for units above 150 MW. Lurgi does not actively market in the US.

CFB units have been increasing in size over the last 15 years, with the largest US operating CFB units at 300 MW (JEA Northside). The largest unit in operation is the ENEL Sulcis Unit in Sardinia, Italy. This Alstom unit is the equivalent of 340 MW, comprised of a 220 MW repowering unit along with additional process steam requirements.

Alstom, Foster Wheeler, and Lurgi have developed designs for single units in the 500 to 600 MW range. Alstom and Foster Wheeler have 600 MW designs, while Lurgi's largest design is 500 MW.

3.6 Current PC and CFB Project Development

There are numerous PC and CFB project currently being developed in the United States. Most of these will employ subcritical and supercritical steam conditions. These projects have been identified by the National Energy Technology Laboratory and are also

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tracked by Black & Veatch as the projects currently in development that may to move forward to construction.[1] These projects are listed in Table 3-7.

Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
MDU / Hardin	116	PRB	Subcritical	MT	2006
Manitowoc / Unit 9	63	Unknown	CFB	WI	2006
Tri-State / Springerville 3	418	PRB	Subcritical	AZ	2006
Santee Cooper / Cross Unit 3	600	Cent. App	Subcritical	SC	2007
XCEL / King	600	PRB	Supercritical	MN	2007
MidAmerican / CB4	790	PRB	Supercritical	IA	2007
Newmont / TS Ranch Plant	203	PRB	Subcritical	NV	2008
Black Hills / Wyg2 Unit 4	90	PRB	Subcritical	WY	2008
WPSC / Weston 4	530	PRB	Supercritical	WI	2008
TXU / Sandow	564	Lignite	CFB	TX	2009
TXU / Oakgrove U1	800	Lignite	Supercritical	TX	2009
TXU / Oakgrove U2	800	Lignite	Supercritical	TX	2009
CWLP / Dallman 34	201	Illinois	Subcritical	IL	2009
EKPC / Spurlock 4	278	Bituminous	CFB	KY	2009
CLECO / Rodemacher	600	Petcoke	CFB	LA	2009
Santee Cooper / Cross Unit 4	600	Cent.App.	Subcritical	SC	2009
WE Energies / Elm Road 1	615	Illinois	Supercritical	WI	2009
OPPD / Nebraska City 2	663	PRB	Subcritical	NE	2009
Salt River / Springerville 4	400	PRB	Subcritical	AZ	2010
NRG / Big Cajn. II, 4	675	PRB	Supercritical	LA	2010
CUS / Southwest U2	300	PRB	Subcritical	MO	2010
KCP&L / Iatan Unit 2	850	PRB	Supercritical	MO	2010
TXU / Texas Sites	8 x 800	PRB	Supercritical	TX	2010
NAPG / Two Elk	325	PRB	Subcritical	WY	2010

[1] "Tracking New Coal-fired Power Plants," NETL, S. Klara, E Shuster, September 29, 2006

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Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
LG&E / Trimble Cty 2	732	Illinois Basin	Supercritical	KY	2010
LSP / Plum Point 1	665	PRB	Supercritical	AR	2010
CPS / Spruce 2	758	PRB	Subcritical	TX	2010
WE Energies / Elm Road 2	615	Illinois	Supercritical	WI	2010
XCEL / Comanche 3	750	PRB	Supercritical	CO	2010
Sierra Pacific / Ely Energy Ctr	750	Unknown	Supercritical	NV	2011
Sithe / Desert Rock 1	750	Unknown	Supercritical	NV	2011
LSP / White Pine	2 x 800	PRB	Supercritical	NV	2011
LSP / Elk Run	750	PRB	Supercritical	IA	2011
Peabody CMS / Prairie Stste 1	750	Illinois	Supercritical	IL	2011
Sunflower / Holcomb 2	600	PRB	Supercritical	KS	2011
LSP / Sandy Creek,	800	PRB	Subcritical	TX	2011
WF&Brazos / Hugo 2	750	PRB	Supercritical	OK	2011
Duke / Cliffside Unit 5	800	Bituminous	Supercritical	NC	2011
EKPC / J.K. Smith 1	278	Bituminous	CFB	KY	2011
S Mont.-SME / Highwood	250	Montana	CFB	MT	2011
Basin Elec. / Dry Fork-	385	PRB	Subcritical	WY	2011
AEP / Hempstead	650	PRB	Ultra-Supercritical	AR	2011
AECI / Norborne 1	660	PRB	Supercritical	MO	2011
Big Stone II Owners / Big Stone II	600	PRB	Supercritical	SD	2012
Santee Cooper / Great Pee Dee River 1	600	East KY Bituminous	Supercritical	SC	2012
NRG / Limestone U3	800	PRB	Supercritical	TX	2012
Sithe / Desert Rock 2	750	Unknown	Supercritical	NV	2012
Sithe / Toquop	750	Unknown	Supercritical	NV	2012
Alliant-WP&L	300	PRB & Bit	CFB	WI	2012
AMP Ohio	500	Bituminous & PRB	Unknown	OH	2012
FPL / FGPP Unit 1	1000	Bituminous	Ultra-Supercritical	FL	2012
UAMPs/Pacificorp / IPP 3	900	UT/CO	Unknown	UT	2012
AEP / Red Rock	900	PRB	Ultra-Supercritical	OK	2012
Sunflower / Holcomb 3	700	PRB	Supercritical	KS	2012
LSP / Longleaf	2 x 600	PRB/Bit.	Unknown	GA	2012

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Table 3-7. Currently Announced PC and CFB Project Developments.

Project/Company	Size (MW)	Fuel	Technology	Location	Expected COD
Peabody-CMS / Prairie Stats 2	750	Illinois	Supercritical	IL	2012
Dominion / Wise Co. VA	600	Bit, Waste Coal/Bio	CFB	VA	2012
BPU / Nearman Cr 2	235	PRB	Subcritical	MO	2012
Duke / Cliffside 7	800	Bituminous	Supercritical	NC	2012
Seminole / Palatka 3	750	Bituminous /Illinois 6 /Petcoke	Supercritical	FL	2012
PPGA / Hastings 2	220	PRB	Subcritical	NE	2012
PacificCorp / Hunter Unit 4	400	Unknown	Supercritical	UT	2013
Santee Cooper / Great Pee Dee River U2	600	East KY Bituminous	Supercritical	SC	2013
Alliant-IP&L	600	PRB	Supercritical	IA	2013
AMP Ohio	500	Ohio & PRB	Unknown	OH	2013
Sunflower / Holcomb 4	600	PRB	Supercritical	KS	2013
JEA/FMPA / Taylor	800	Bituminous	Supercritical	FL	2013
PacificCorp / J. Bridger 4	750	PRB	Supercritical	WY	2014
FPL / FGPP Unit 2	1000	Bituminous	Ultra-Supercritical	FL	2013
Sierra Pacific / Ely Energy Ctr 2	750	Unknown	Supercritical	NV	2014
Tri-State / CO Coal Unit	656	PRB	Supercritical	KS	2020

Note:
This list is a compilation of known projects as published by NETL and Black & Veatch, independently. Not all data can be verified.

3.7 Post Combustion Carbon Capture

For PC and CFB technologies, the likely approach for CO_2 capture would be a post-combustion CO_2 capture process. In CO_2 capture, the CO_2 concentration and the CO_2 partial pressure in the gas stream are important variables. Higher concentrations and higher partial pressures of CO_2 facilitate its capture. The relatively low concentration of CO_2 in the flue gas makes the CO_2 capture process difficult.

Because the carbon capture technology is implemented as "post-combustion" for PC and CFB technologies, the steam generation equipment is constructed and operated the same as it would be for a plant without carbon capture. The resulting flue gas would be treated by removing the CO_2, which would then be dehydrated, compressed, and transported.

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The addition of a carbon capture process would have a significant impact on the output and heat rate of a PC or CFB facility. Significantly higher auxiliary loads are required for additional pumps, fans, and miscellaneous loads in the capture process, and thermal energy in the form of process steam is required to separate the CO_2 from the absorption solvent. Energy would also be required for captured CO_2 compression. These energy requirements would have an impact on the net plant output and net plant heat rate of the facility. In order to maintain project required net plant output, additional generation capacity would need to be installed to compensate for the increased auxiliary loads of the carbon capture process. The increase in gross plant generation would meet the carbon capture process energy requirements.

Typically, CO_2 capture from the flue gas of a post-combustion process for a conventional coal technology plant has been thought to employ absorption using monoethanol amine (MEA), a chemical solvent that is commercially available and widely used. The CO_2 capture plant would consist of flue gas preparation, CO_2 absorption, CO_2 stripping, and CO_2 compression.

For an MEA CO_2 capture process, an auxiliary load in the range of 20 to 30 percent of gross plant output can be expected which would require additional capacity of 30 to 40 of gross plant output in order to maintain project required net capacity. The capital requirements for CO_2 capture addition would need to include both the CO_2 capture equipment and the capital required for additional capacity.

A new and developing alternative to the MEA CO_2 capture process is a chilled ammonia CO_2 absorption process, currently under development by Alstom. Compared to the MEA absorption process, the chilled ammonia absorption process appears to have the potential to significantly reduce the energy and capital requirements to achieve post-combustion CO_2 capture. A schematic of this process is shown in Figure 3-7. The description provided here is based on data presented in a position paper published by Alstom.[1]

For a CO_2 capture process employing Alstom's chilled ammonia absorption, the flow would begin at the flue gas discharge from the plant FGD. First, the flue gas would be cooled from a typical FGD exit temperature of 120 to 140° F to approximately 35° F. Flue gas cooling can be achieved by cooling towers and mechanical chillers. The power consumed by the cooling process is estimated by Alstom to consume one to two percent of the gross plant output. Reducing the temperature of the flue gas would have the effect of condensing out saturated water in the flue gas introduced by the FGD and any residual contaminants remaining in the flue gas. In addition, cooling the flue gas to a lower

[1] "Chilled Ammonia Process for CO2 Capture," Alstom, November 2006.

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temperature will reduce the volume of the flue gas (a volume reduction of approximately 33 percent will occur when cooled from 140° F to 32° F). The reductions in mass flow rate resulting from moisture removal and volumetric flow rate of the flue gas may reduce the size, energy requirements and capital costs of downstream capture equipment.

Once the flue gas is cooled, the CO_2 absorption takes place in an absorption module similar to an FGD absorption module. A slurry containing a mixture of dissolved and suspended ammonium carbonate and ammonium bisulfate is discharged in the module against an upward flow of flue gas. More than 90 percent of the CO_2 contained in the flue gas is absorbed in the slurry. Any ammonia transferred to the flue gas by the absorption process would be captured by a cold-water wash process and returned to the slurry. After CO_2 absorption, the slurry is regenerated in a high pressure regenerator. Regenerating the slurry at a high pressure reduces the energy requirements for CO_2 compression once it is stripped from the slurry. CO_2 is stripped from the slurry by thermal energy addition which is obtained from a heat exchanger prior to injection in to the regenerator and heat addition by a reboiler in the regenerator. Any ammonia or water vapor contained in the CO_2 gas stream stripped from the slurry is removed in a cold-water wash at the top of the absorber.

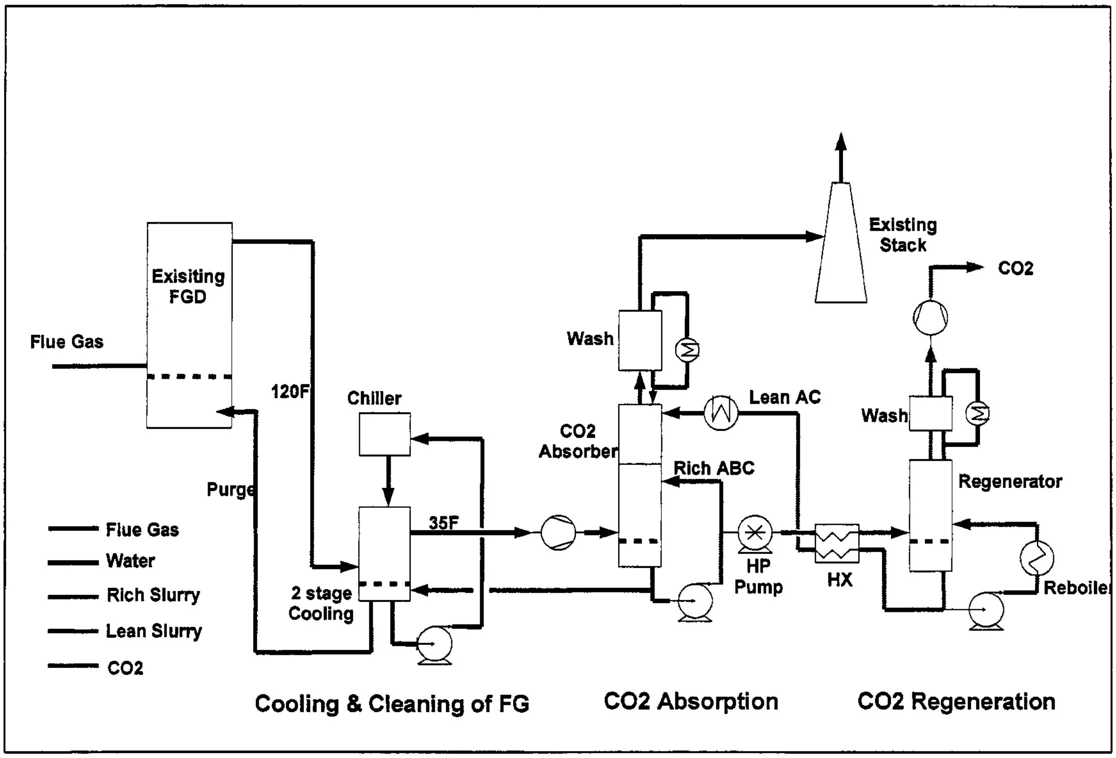

Figure 3-7. Schematic of Ammonia-Based CO_2 Capture System.

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The primary advantage of the Alstom chilled ammonia CO_2 absorption process compared to MEA is the reduced operating energy requirements and capture costs. In a reference study prepared by Alstom comparing their ammonia absorption process to an MEA absorption process, the ammonia absorption process had a significantly reduced affect on net plant output and net plant heat rate. In addition, the cost of capture in dollar per avoided ton of CO_2 was less than half that expected with MEA.

Alstom's chilled ammonia CO_2 absorption process is still in development. Alstom projects the offering of a commercial product before the end of 2011. An Alstom press release dated October 2, 2006, announced a collaborative project between Alstom, the Electric Power Research Institute (EPRI) and We Energies to build a 5 MW pilot plant that will demonstrate the CO_2 capture process. The facility will be constructed at a power plant owned by We Energies in Pleasant Prairie, Wisconsin and is expected to be commissioned in mid-2007. The demonstration facility will give Alstom and EPRI the opportunity to evaluate the process on a larger commercial scale moving from bench scale testing.

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4.0 IGCC Technologies and Industry Activity

This section contains a summary-level description of IGCC technologies, including a review of IGCC experience and a discussion of the issues related to commercializing the technology.

Reliability is expected to be lower for an IGCC plant than for a PC or CFB plant with respect to producing electricity from coal. IGCC plants without spare gasifiers are expected to achieve long-term annual availabilities in the 80 to 85 percent range on coal versus approximately 90 percent for PC and CFB. IGCC availability on coal during initial startup and the first several years of operation is expected to be significantly lower. A generation plant that uses IGCC technology could increase the availability by firing the combined cycle portion of the plant on a backup fuel such as natural gas when syngas is not available from coal gasification. The cost, availability, and air emissions of backup fuel firing may limit or prevent its use. Currently, natural gas is not available at FGPP. The installation of a relatively long natural gas pipeline would be required if natural gas were to be used as a backup fuel. Large capital cost would be required for the installation of a natural gas pipeline to FGPP. Additional capital would also be required for the installation all associated equipment required to operate the combined cycle on natural gas. These large capital requirements would not be justified by the incremental benefit of increased plant availability with higher cost natural gas as a backup fuel. Because of this, the use of natural gas as a backup fuel for an IGCC plant at FGPP would not be economically feasible. Likewise, using fuel oil as a backup fuel to enhance syngas production reliability would also be prohibitively expensive and logistically cumbersome.

Cost, schedule, and plant availability issues cause IGCC projects to have higher financial risk than conventional PC or CFB power generation projects. Details regarding the guarantee levels for cost, schedule, and performance; the associated liquidated damages clauses and risk premium; and availability assurances are not well defined at this time. It is expected that the standards for contractual arrangements between owners and constructors will evolve based on the experiences of the next generation of IGCC project development.

4.1 Gasification Technologies and Suppliers

Gasification is a mature technology with a history that dates back to the 1800s. The first patent was granted to Lurgi GmbH in Germany in 1887. By 1930, coal gasification had become widespread and in the 1940s, commercial coal gasification was used to provide "town" gas for streetlights in both Europe and the United States.

Currently, there are four main types of gasifiers:

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- Entrained flow
- Fixed bed
- Fluidized bed
- Transport bed

The following listing includes the most notable technology suppliers by type:

- Entrained Flow Gasifiers:
  - ConocoPhillips (COP) (E-Gas, formerly Global Energy, originally Dow-Destec).
  - General Electric (GE) (formerly ChevronTexaco, originally Texaco).
  - Mitsubishi Heavy Industries (MHI).
  - Shell.
  - Siemens GSP (formerly Noell).
- Fixed Bed (or Moving Bed) Gasifiers:
  - BGL (slagging, Global Energy, formerly British Gas Lurgi).
  - Lurgi (dry bottom).
- Fluidized Bed Gasifiers:
  - Carbona (formerly Tampella).
  - HTW (formerly High Temperature Winkler).
  - KRW.
  - Lurgi.
- Transport Bed Gasifiers:
  - KBR.

Entrained flow gasifiers have been operating on oil feedstock since the 1950s and on coal and petcoke feedstock since the 1980s. Entrained flow gasifiers operate at high pressure and temperature, have very low fuel residence times, and have high feedstock capacity throughputs. Fixed bed gasifiers have operated on coal feedstock since the 1940s. Compared to entrained flow gasifiers, fixed bed gasifiers operate at lower pressure and temperature, have much longer fuel residence times, and have lower capacity throughputs. Fluidized bed gasifiers have operated on coal since the 1920s. Compared to entrained flow gasifiers, fluidized bed gasifiers operate at lower pressure and temperature, use air instead of oxygen, have longer fuel residence times, and have lower capacity throughput. Transport bed gasifiers have only recently been tested on a small scale. Compared to entrained flow gasifiers, transport gasifiers operate at lower pressure and temperature, use air instead of oxygen, have longer fuel residence times, and have lower capacity throughput.

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Limestone is fed with coal to fluidized bed and transport bed gasifiers for capturing sulfur as calcium sulfide (CaS), which is typically oxidized to $CaSO_4$ for landfill disposal. Entrained flow and fixed bed gasifiers treat the syngas from gasification to remove the sulfur-containing constituents as elemental sulfur or sulfuric acid (H_2SO_4), which can be sold. The ash from fluidized bed, transport bed, and dry bottom fixed bed gasifiers is leachable and is typically landfilled. Entrained flow and slagging fixed bed gasifiers operate above the ash fusion temperature and produce a nonleachable slag that can be sold.

Entrained flow and fixed bed gasifiers generally use high purity oxygen as the oxidant. Fluidized bed and transport gasifiers use air instead of oxygen. Since high purity oxygen does not contain the large concentration of nitrogen present in air, equipment size can be reduced commensurately. Higher gasifier operating pressures are also more economical for the smaller gas flow rates and equipment size associated with high purity oxygen use. Entrained flow gasifiers have higher operating temperatures and lower residence times than fluidized and transport bed gasifiers. These conditions typically require the use of high purity oxygen for entrained flow gasifiers. An oxygen purity of 95 percent by volume is the optimum for entrained flow gasifiers producing syngas for combustion turbine fuel. Oxygen purities of 98 percent or higher are required when the syngas is used to produce chemicals and liquid fuels.

Entrained flow gasifiers are relatively new technologies compared to fluidized bed and fixed bed gasifiers. Entrained flow gasifiers have been operating successfully on solid fuels since the mid-1980s to produce chemicals and since the mid-1990s to produce electricity in four commercial-scale IGCC demonstration plants, located in Europe (two units) and the US (two units).

Transport bed gasification technology is a recent development that has not yet been demonstrated on a commercial scale. The Southern Company and KBR have been testing a 30 tpd air-blown transport reactor integrated gasification (TRIG) system at the US DOE-funded Power Systems Development Facility (PSDF) at Wilsonville, Alabama. TRIG employs KBR catalytic cracking technology, which has been used successfully for more than 50 years in the petroleum refining industry. In 2004, the US DOE awarded $235 million to the Southern Company and the Orlando Utilities Commission (OUC) to build a 285 MW IGCC Plant at the Stanton Energy Center in Florida to demonstrate TRIG combined cycle technology under the Clean Coal Power Initiative (CCPI) program. The total cost of this plant is estimated to be $792 million. The proposed plant will gasify subbituminous coal. Southern Company estimates that the plant heat rate will be

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approximately 8,400 Btu/kWh (HHV coal).[1] The demonstration plant is scheduled to start up in or after 2010. Results from this commercial-scale demonstration plant should determine whether TRIG technology will be competitive with entrained flow gasifier technology.

At this time, based on their characteristics and level of development, oxygen-blown entrained flow gasifiers are the best choice for high capacity gasification for power generation.

4.2 Entrained Flow Gasification Process Description

A typical IGCC process flow diagram is shown on Figure 4-1.

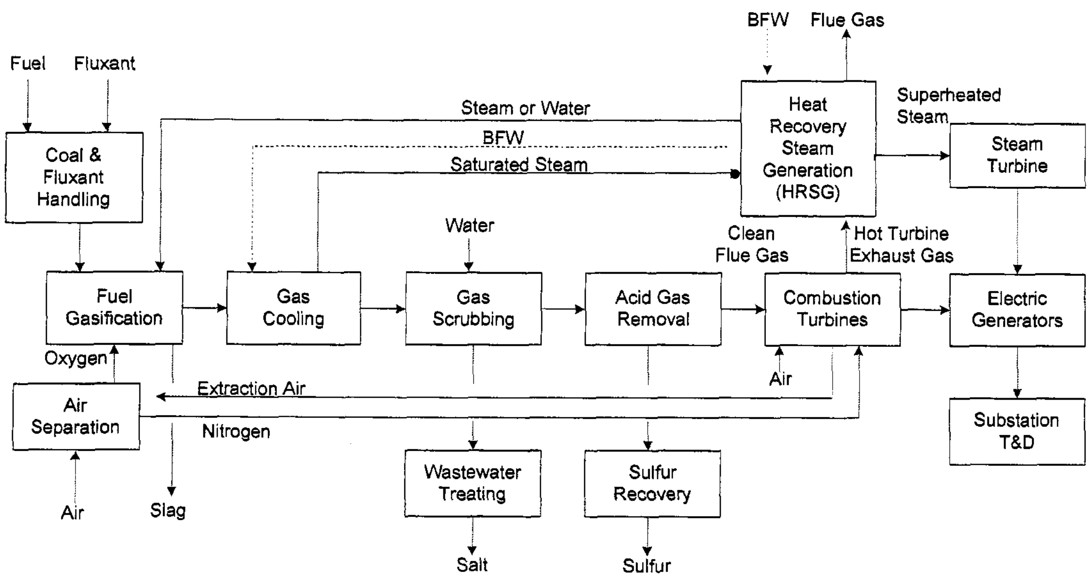

Figure 4-1. IGCC Process Flow Diagram

Gasification consists of partially oxidizing a carbon-containing feedstock (solid or liquid) at a high temperature (2,500 to 3,000° F) to produce a syngas consisting primarily of CO and hydrogen. A portion of the carbon is completely oxidized to carbon dioxide (CO_2) to generate sufficient heat required for the endothermic gasification reactions. (The CO_2 proportion in the syngas from the gasifier ranges from 1 percent for the dry feed Shell gasifier to more than 15 percent for the slurry feed COP and GE gasifiers.) The gasifier operates in a reducing environment that converts most of the sulfur in the feed to hydrogen sulfide (H_2S). A small amount of sulfur is converted to carbonyl sulfide

[1] At average ambient conditions, and assumed new and clean.

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(COS). Some sulfur remains in the ash, which is melted and then quenched to produce slag. Other minor syngas constituents include ammonia (NH_3), hydrogen cyanide (HCN), hydrogen chloride (HCl), and entrained ash, which contains unconverted carbon. In IGCC applications, the minimum gasifier pressure is typically 450 to 550 psia. This pressure is determined by the combustion turbine syngas supply pressure requirements. GE gasifiers operate at higher pressures, up to 1,000 psia, and the excess syngas pressure is let down in an expander to produce additional power.

A fluxant may need to be fed with the coal to control the slag viscosity so that it will flow out of the gasifier. Fluxant addition is less than 2 percent of the coal feed. The fluxant can be limestone, PC boiler ash, or, in some cases, dirt. The required fluxant composition and proportion will vary with the coal feed composition. The gasification process operators must know the feed coal composition and make fluxant adjustments when the coal composition changes. Too little fluxant can allow excessive slag to accumulate in the gasifier, which could damage the refractory and eventually choke the gasifier. Too much fluxant can produce long cylindrical slag particles instead of small slag granules when the slag is quenched in the lockhopper. These long thin slag particles will plug up the slag lockhopper.

Solid fuel feeds to the gasifier can be dry or slurried. Solid fuels slurried in water do not require the addition of steam for temperature moderation. While slurries typically use water, oil can also be used. Steam is added to the oxygen as a temperature moderator for dry solid feed gasifiers, solid feeds slurried in oil, and oil feed gasifiers.

Entrained flow gasifiers use oxygen to produce syngas heating values in the range of 250 to 300 Btu/scf on an HHV basis[1]. Oxygen is produced cryogenically by compressing air, cooling and drying the air, removing CO_2 from the air, chilling the feed air with product oxygen and nitrogen, reducing the air pressure to provide autorefrigeration and liquefy the air at -300° F, and separating the liquid oxygen and liquid nitrogen by distillation. Air compression consumes a significant amount of power, between 13 and 17 percent of the IGCC gross power output.

Hydrogen in syngas prevents the use of dry low NO_x (DLN) combustors in the combustion turbines. The dilution of the syngas to reduce flame temperature is required for NO_x control. Syngas is typically diluted by adding water vapor and/or nitrogen. Water vapor can be added to the syngas by evaporating water using low level heat. Nitrogen can be added by compressing excess nitrogen from the air separation unit (ASU) and adding it to the syngas either upstream of the combustion turbine or by injection into the combustion turbine. Syngas dilution for NO_x control increases the mass

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[1] Comparatively, pipeline quality natural gas has a heating content of about 950 to 1,000 Btu/scf (HHV).

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flow through the combustion turbine, which also increases power output. GE combustion turbines inject this diluent nitrogen separately from the syngas into the same ports used for steam or water injection. For MHI and Siemens Power Generation (SPG – formerly known as Siemens Westinghouse or SW) combustion turbines, diluent nitrogen is premixed with the syngas. The nitrogen supply pressure required for injection into a GE 7FB is 405 psia versus 450 to 500 psia for mixing with the syngas for the MHI 501F and the SPG SGT6-5000F (previously referred to as the SW 501FD). The diluted syngas has a heat content of 140 to 150 Btu/scf. However, the mass flow of the diluted syngas is eight times that of natural gas, which increases the combustion turbine power output by up to 16 percent, when no air is extracted for the ASU. A portion of the combustion turbine compressed air may be extracted for feed to the ASU. The ASU and combined cycle are integrated by the nitrogen and air exchanges. Extracting compressed air from the combustion turbine improves overall efficiency, but it adds complexity to the process, including longer startup periods, if there is no separate source of startup compressed air. The prevailing thought is to minimize or avoid compressed air integration.

The raw hot syngas is cooled by the boiler feedwater from the HRSG to a temperature suitable for cleaning. The syngas cooling process generates steam. The steam quantities and pressures vary with the gasification process design. Gasification steam is subsequently integrated into the steam cycle.

Before the raw syngas enters the combustion turbine combustor, the H_2S, COS, NH_3, HCN, and particulates must be removed. Cooled syngas is scrubbed to remove NH_3, water soluble salts, and particulates. Syngas may also be filtered to remove additional particulates. COS in the syngas is hydrolyzed by a catalyst to H_2S, which is removed from the syngas by absorption in a solvent. This absorption process is called acid gas removal (AGR).

Syngas is filtered in ceramic candle filters at the Buggenum and Puertollano IGCC plants. At the Wabash IGCC plant, syngas was initially filtered in ceramic candle filters; later, the filter elements (candles) were changed to sintered metal. The syngas filters at the Buggenum, Puertollano, and Wabash plants are located upstream of the AGR. At the Polk County IGCC plant, syngas is filtered in cartridge filters downstream from the AGR.

The H_2S that is removed from the syngas by absorption in a solvent is desorbed as a concentrated acid gas when the solvent is regenerated, by lowering its pressure and increasing its temperature. Descriptions of commercial AGR systems are provided in Section 4.9. The acid gas stream is typically converted to elemental sulfur in the Claus sulfur recovery process, although it is also possible to produce sulfuric acid.. The primary chemical reaction in the Claus process is the reaction of H_2S and SO_2 to produce

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elemental sulfur and water. This reaction requires a catalyst and is performed in two stages. The SO_2 is produced by oxidizing (burning) one third of the H_2S in the feed gas. External fuel is only needed to initially heat up the Claus thermal reactor and initiate combustion of the acid gas. Under normal operation, the oxidation of H_2S provides sufficient heat to maintain the reaction. The sulfur is formed as a vapor; the S_2 form of sulfur reacts with itself to produce S_6 and S_8, which are subsequently condensed. This condensed liquid sulfur is separated from the residual gas and stored in a pit at 275° to 300° F. As required, the liquid sulfur is pumped from the pit to railcars for shipment. Solid sulfur can be produced in blocks or pellets by cooling the liquid sulfur to ambient temperature. The residual (tail gas) is primarily CO_2 and nitrogen, which are compressed and reinjected into the syngas upstream of the AGR.

4.3 Gasification Technology Suppliers

Today, there are three major entrained flow coal gasification technology suppliers:

- COP, which licenses E-Gas technology that was developed by Dow. COP purchased this technology from Global Energy in August 2003.
- GE, which purchased Texaco gasification technology from ChevronTexaco in June 2004. GE offers both Quench and Radiant (high temperature heat recovery [HTHR]) cooler gasifiers.
- Shell, which developed its gasification technology in conjunction with Prenflo. Prenflo technology is no longer licensed.

The other entrained flow gasifiers listed in Section 4.1 are not currently strong competitors in the utility-scale IGCC market because of the relative maturity of the technology. MHI is developing an air-blown, two-stage entrained flow gasifier with dry feed. MHI intends to demonstrate this technology at a 250 MW project in Japan. Siemens (formerly Sustec GSP, FutureEnergy, and Noell) has one small gasification plant (Schwarze Pumpe, 200 MW_{th} methanol and power cogeneration). Its technology has been geared toward biomass and industrial processing on a smaller scale, but it seems to be making an entry into the utility-scale power generation market. According to a May 2006 press release, Siemens plans to build a 1,000 MW coal IGCC in Germany as a first step to commercializing its newly acquired IGCC technology. Multiple other GSP coal gasification projects are currently being implemented, including three in China that wil produce ammonia and methanol.

The COP and GE gasifiers are refractory lined with coal-water slurry feed. In the late 1970s, Shell and Krupp-Koppers jointly developed a waterwall type gasifier with

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dry, pulverized coal feed specifically for IGCC power generation for a 150 ltpd demonstration plant near Hamburg, West Germany. During the 1990s, Shell and Krupp-Koppers licensed their gasification technology separately. The Puertollano, Spain IGCC plant, which was built in the mid-1990s, uses Krupp-Kopper's Prenflo gasification technology. In the late 1990s, Krupp-Koppers merged with Uhde, and Uhde reached an agreement with Shell to license Shell gasification technology and no longer market the Prenflo gasification process. Uhde has incorporated its Prenflo experience into Shell's coal gasification process technology.

Each of the three commercial, entrained flow coal gasification technologies generates similar syngas products. All three gasifiers react the coal with oxygen at high pressure and temperature to produce a syngas consisting primarily of hydrogen and CO. The raw syngas from the gasifier also contains CO_2, water, H_2S, COS, NH_3, HCN, and other trace impurities. The syngas exits the gasifier reactor at approximately 2,500 to 2,900° F.

Each of the COP, GE, and Shell gasification processes cools the hot syngas from the gasifier reactor differently. In the COP process, the hot syngas is partially quenched with coal slurry, resulting in a second stage of coal gasification. The raw syngas from the COP gasifier may also contain methane and products of coal devolatilization and pyrolysis because of its two-stage gasification process. The partially quenched syngas is cooled with recycled syngas to solidify the molten fly slag and then further cooled to produce HP steam in a vertical shell and tube heat exchanger. (Syngas flow is down through the tubes. Boiler water and steam flow is up through the shell side.) Unconverted coal is filtered from the cooled syngas and recycled to the gasifier first stage. GE has two methods for cooling the hot syngas from the gasifier: radiant cooling to produce HP steam via HTHR and water quench with low-pressure (LP) steam generation. In the Shell process, hot syngas is cooled with recycled syngas to solidify the molten fly slag and then further cooled in a convective cooler to produce high-temperature steam.

The cooled, raw syngas is cleaned by various treatments, including filtration, scrubbing with water, catalytic conversion, and scrubbing with solvents, as discussed in Section 4.9. The clean syngas that is used as combustion turbine fuel contains hydrogen, CO, CO_2, water, and parts per million (ppm) concentrations of H_2S and COS.

4.4 Gasifier Technology Selection

Table 4-1 provides process design characteristic data for the COP, GE, and Shell gasification technologies for systems that would generally be considered for a facility of this size and type. The Shell gasification technology has the highest cold gas efficiency,

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because the gasifier feed coal is injected into the gasifier dry, whereas with the COP and GE gasifiers, the feed is a slurry of coal in water. However, the Shell dry feed coal gasification process has a higher capital cost. Cooling the hot syngas to produce HP steam also contributes to higher IGCC efficiency, but with a higher capital cost. Shell and COP generate HP steam from syngas cooling. GE offers both HP steam generation using Radiant syngas coolers and LP steam generation using its Quench process, which has a significantly lower capital cost than the Radiant. The COP and GE gasifiers are refractory lined, while the Shell gasifier has an inner water tube wall (membrane). The refractory-lined gasifiers have a lower capital cost, but the refractory requires frequent repair and replacement. The COP and GE gasifier burners typically require more frequent replacement than the Shell gasifier burners.

Table 4-1. Comparison of Key Gasifier Design Parameters

Technology	COP	GE Quench	GE HTHR	Shell
Gasifier Feed Type	Slurry	Slurry	Slurry	Dry N_2 Carrier
Gasifier Burners	Two Stage: First Stage--Two horizontal burners Second Stage--One horizontal feed injector w/o O_2	Single Stage--One vertical burner	Single Stage--One vertical burner	Single Stage--Four to eight horizontal burners
Gasifier Vessel	Refractory lined	Refractory lined	Refractory lined	Waterwall membrane
Syngas Quench	Coal Slurry and Recycle Gas	Water	None	Recycle Gas
Syngas Heat Recovery	Firetube HP WHB	Quench LP WHB	Radiant HP WHB	Watertube HP WHB
Coal Cold Gas Efficiency, HHV	71 to 80 percent	69 to 77 percent	69 to 77 percent	78 to 83 percent
Coal Flexibility	Middle	Low	Low	High
Capacity, stpd	3,000 to 3,500	2,000 to 2,500	2,500 to 3,000	4,000 to 5,000

WHB--Waste Heat Boiler

It is worth mentioning gasifier sizing issues with respect to the Shell and GE Quench technologies. Shell has stated that its maximum gasifier capacity is 5,000 stpd of dried coal, which is large enough to supply syngas to two GE 7FB or Siemens SGT6-5000F combustion turbines. GE offers gasifiers in three standard sizes: 750, 900, and 1,800 ft^3. The largest Quench gasifier that GE currently offers is 900 ft^3. The maximum

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capacity of this gasifier is approximately 2,500 tpd of as-received coal and does not produce enough syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine. The largest Radiant gasifier that GE currently offers is 1,800 ft^3, which will supply sufficient syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine. COP currently offers a gasifier that will supply sufficient syngas for a GE 7FB or Siemens SGT6-5000F combustion turbine.

Overall, energy conversion efficiencies for IGCC plants vary with the gasification technology type, system design, level of integration, and coal composition. The gasifier efficiency of converting the coal fuel value to the syngas fuel value (after sulfur removal) is known as the cold gas efficiency, which is generally expressed in HHV. The values for cold gas efficiency in Table 4-1 are indicative of the range of achievable performance for coal and petcoke. Cold gas efficiency for the Shell dry coal feed process is about 3 percent higher than the coal-water slurry feed gasification processes for low moisture coal. This difference increases with coal moisture content. HP steam generation from syngas cooling increases IGCC efficiency by about 2 percent over that of water quench.

4.5 Commercial IGCC Experience

There have been approximately 18 IGCC projects throughout the world, as listed in Table 4-2. Of these, fifteen were based on entrained flow gasification technology. Nine of the projects were coal based, two are petcoke based, one is sludge based, and the other six are oil based. Two of the coal-based IGCC plants, Cool Water in California and the Dow Chemical Plaquemine Plant in Louisiana, were small demonstration projects and have been decommissioned. Another small coal IGCC demonstration project was Sierra Pacific's Piñon Pine Project in Nevada. This project, based on KRW fluidized bed technology, was not successful.

Of the six operating coal IGCC plants, one is a 40 MW plant that coproduces methanol using a Noell gasifier, one is a 350 MW lignite cogeneration plant that has 26 Lurgi fixed bed gasifiers, and four are commercial-scale, entrained flow gasification demonstration projects (ranging in capacity from 250 to 300 MW) that are located in Florida, Indiana, The Netherlands, and Spain. The Wabash Indiana IGCC plant did not operate for an extended period in 2004 and 2005 because of contractual problems, but is currently back in operation. Design data for these four demonstration plants are listed in Table 4-3. None of these demonstration units is of the same capacity scale as that required for the FGPP units.

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Table 4-2. IGCC Projects – All Fuels

Owner - Location	Year[(1)]	MW	Application	Fuel	Gasifier
SCE Cool Water[(2)] – USA (CA)	1984	120	Power	Coal	Texaco (GE)
Dow LGTI Plaquemine – Plaquemine[(2)] - USA (LA)	1987	160	Cogen	Coal	COP (Destec)
Nuon Power – Netherlands	1994	250	Power	Coal	Shell
PSI/Global Wabash – USA (IN)	1995	260	Repower	Coal	E-Gas (COP)
TECO Polk County – USA (FL)	1996	250	Power	Coal	Texaco (GE)
Texaco El Dorado[(3)] – USA (KS)	1996	40	Cogen	Petcoke	Texaco (GE)
SUV - Czech Republic	1996	350	Cogen	Coal	Lurgi[(5)]
Schwarze Pumpe - Germany	1996	40	Power/ Methanol	Lignite	Noell
Shell Pernis Refinery - Netherlands	1997	120	Cogen/Hydrogen	Oil	Shell
Elcogas - Spain	1998	300	Power	Coal/ Petcoke	Prenflo
Sierra Pacific[(4)] – USA (NV)	1998	100	Power	Coal	KRW[(6)] - Air
ISAB Energy - Italy	1999	500	Power/Hydrogen	Oil	Texaco (GE)
API - Italy	2000	250	Power/Hydrogen	Oil	Texaco (GE)
Delaware City Refinery - USA (DE)	2000	180	Repower	Petcoke	Texaco (GE)
Sarlux/Sara Refinery - Italy	2000	550	Cogen/Hydrogen	Oil	Texaco (GE)
ExxonMobil - Singapore	2000	180	Cogen/Hydrogen	Oil	Texaco (GE)
FIFE - Scotland	2001	120	Power	Sludge	BGL[(5)]
NPRC Negishi Refinery - Japan	2003	342	Power	Oil	Texaco (GE)

(1)First year of operation on syngas.
(2)Retired.
(3)The El Dorado Refinery is now owned by Frontier Refining.
(4)Not successful.
(5)Fixed bed.
(6)Fluidized bed.

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Table 4-3. Coal-Based IGCC Demonstration Plants [1]				
Project	**Nuon Power**	**Wabash [3]**	**TECO Polk County [4]**	**Elcogas**
Location	Buggenum, Netherlands	Indiana	Florida	Puertollano, Spain
Technology	Shell	E-Gas (COP)	Texaco (GE)	Prenflo (Krupp)
Startup Year	1994	1995	1996	1998
Net Output, design, MW	252	262	250	300[5]
HHV Efficiency, net design, percent	41.4	37.8	39.7	41.5
Height, ft	246	180	295	262
Fuel, design	Coal	Coal	Coal	50% coal/50% petcoke
Fuel Consumption, tpd	2,000	2,200	2,200	2,600
Fuel Feed	Dry N_2 lockhopper	Wet slurry	Wet slurry	Dry N_2 lockhopper
Syngas HHV, Btu/scf	300	276	266	281
CTG Model	Siemens V94.2	GE 7FA	GE 7FA	Siemens V94.3
Firing temperature, °F	2,012	2,300	2,300	2,300
Combustors	Twin vertical silos	Multiple cans	Multiple cans	Twin horizontal silos
CTG Output, design, MW	155	192	192	200
STG Output, design, MW	128	105	121	135
Auxiliary Power, design, MW	31	35.4	63	35
Net Output, design, MW	252	262	250	300
Net Output, achieved, MW	252	252	250	300
NPHR, design, Btu/kWh HHV	8,240	9,030	8,600	8,230
NPHR, achieved, Btu/kWh HHV [2]	8,240	8,600 - Adjusted for HRSG feedwater heaters	9,100 - Adjusted for gas/gas heat exchanger	8,230
ASU Pressure, psi	145	72.5	145	145
Nitrogen Usage	Syngas Saturator	Vented	CTG NO_x Control	Syngas Saturator

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Table 4-3. Coal-Based IGCC Demonstration Plants [1]

Project	Nuon Power	Wabash [3]	TECO Polk County [4]	Elcogas
NO_x Control	Saturation and N_2 dilution	Saturation + steam injection	N_2 dilution to combustors	Saturation and N_2 dilution
NO_x, 6% O_2, mg/Nm^3	25	100 to 125	100 to 125	150
Slag Removal	Lockhopper	Continuous	Lockhopper	Lockhopper
Recycle Gas Quench	50% of gas, to 1,650° F	Some in second stage	None	67% of gas, to 1,475° F
Integration				
Water/steam	Yes	Yes	Yes	Yes
N_2 Side ASU/CTG	Yes	No	Yes	Yes
Air Side ASU/CTG	Yes	No	No	Yes
Add Air Compressor	Yes	Yes	Yes	No
Gas Cleanup				
Particulate Removal	Cyclone/Ceramic candle filter	Sintered metal candle filter	Water wash	Ceramic candle filter
Chloride Removal	Water scrubbing	Water scrubbing	Water scrubbing	Water scrubbing
COS Hydrolysis	Yes	Yes	Retrofit in 1999	Yes
AGR Process	Sulfinol	MDEA	MDEA	MDEA
Sulfur Recovery	Claus + SCOT TGR	Claus + Tail Gas Recycle	H_2SO_4 Plant	Claus + Tail Gas Recycle
SO_2, 6% O_2, mg/Nm^3	35	40	40	25

[1] Information taken from "Operating Experience and Improvement Opportunities for Coal-Based IGCC Plants," Holt, Neville from *Science Reviews – Materials at High Temperatures*, Spring 2003. Additional footnotes are by Black & Veatch.

[2] Achieved NPHR are instantaneous values from performance testing. Long term annual average heat rates vary with degradation and dispatch profile.

[3] Wabash NPO and NPHR reported as 261 MW and 8,600 Btu/kWh in "The Wabash River Coal Gasification Repowering Project, an Update", USDOE, September 2000.

[4] TECO NPO and NPHR reported as 250 MW and 9,650 Btu/kWh in "Tampa Electric Integrated Gasification Combined Cycle Project", USDOE, June 2004.

[5] Based on ISO conditions. Site specific design NPO was 283 MW, with probable further derate due to higher ASU auxiliary load.

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Each of the four projects was a government-subsidized IGCC demonstration, two in the United States and two in Europe. Each of these IGCC plants consists of a single train (one ASU, one gasifier, one gas treating train, and one combined cycle consisting of one CTG, one HRSG, and one STG). Wabash has a spare gasifier.

Table 4-3 also summarizes the integration in each plant. Basically, there are three major areas for potential integration:

- Water and steam between the power generation area and the gasification island. High- and low-level heat rejection from the gasification process is utilized to produce combined cycle power.
- The nitrogen side of the ASU and CTG--Waste nitrogen is mixed with the syngas to reduce NO_x formation and to increase power output.
- The air side of the ASU and the CTG--Air is extracted from the CTG compressor to reduce the auxiliary power and increase efficiency.

Figure 4-2 depicts potential areas of integration. The European plants have been highly integrated, partly in response to higher fuel prices, while the US plants have been less integrated. Both the Nuon Power Buggenum, Netherlands plant and the Elcogas Puertollano, Spain plant experienced operating difficulties as a result of the highly integrated design. EPRI has suggested that such high integration should be avoided in future designs.

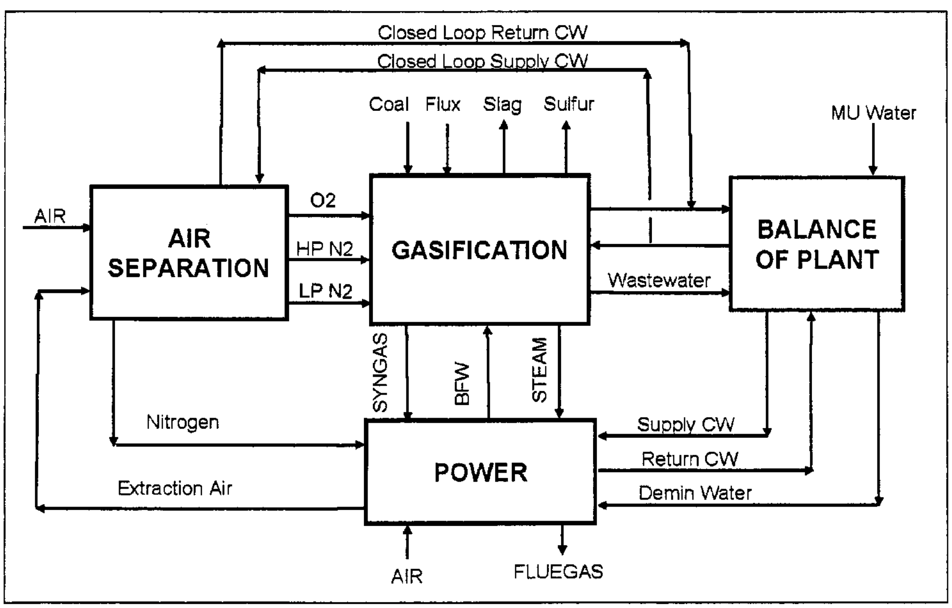

Figure 4-2. Potential Areas for Integration

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The operation of these four commercial coal-fueled IGCC plants has adequately demonstrated capacity, efficiency, and environmental performance, but uncertainty remains regarding availability, reliability, and cost. The complexity and the relative immaturity of the IGCC process increase opportunities for deficiencies in design, vendor-supplied equipment, construction, operation, and maintenance. The high risks of cost overruns and low availability have presented obstacles to the development of nonsubsidized coal-fueled IGCC projects. At present, there are several coal-based IGCC projects being developed in the United States that have or expect to receive subsidies.

4.6 Fuel Characteristics Impact on Gasifier Selection

There are three general coal feedstocks typically considered for IGCC projects: Appalachian, Illinois, and Powder River Basin (PRB). Petcoke is a fourth solid fuel feedstock that is frequently considered for IGCC applications. Petcoke may be a lower cost fuel, but it is not as readily obtainable as coal. Historically, anthracite and lignite coals have not been seriously evaluated for IGCC projects, nor have waste coals such as gob (coal mine waste) and culm (waste produced when anthracite is mined and prepared for market, primarily rock and some coal).

Coal-based operating experience has been focused almost exclusively on bituminous coals (e.g., Pittsburgh No. 8 and Illinois No. 6), and there is also extensive experience with petcoke. Subbituminous (i.e., PRB) coals have been tested only in a limited fashion, but because of the nature of the US coal market and the abundance of PRB coal, there is strong interest in using it for IGCC applications. Typical design values for the coals generally considered for IGCC are listed in Table 4-4.

Table 4-4. As-Received Coal Properties of Typical IGCC Coals

Fuel	Pittsburgh No. 8	Illinois No. 6	PRB
Heat Content, Btu/lb (HHV)	12,300	10,200	8,400
Moisture, percent	8.0	14.1	29.4
Ash, percent	12.0	15.7	6.0
Sulfur, percent	4.0	4.3	0.34

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In the GE gasification process, all of the inherent water in the coal and the liquid water in the slurry must be evaporated in the gasifier by combusting more CO to CO_2, which results in a lower cold gas efficiency than the COP and Shell gasification processes. For low moisture fuels, such as the one in this study, the GE process can be very cost competitive. COP is able to attain a higher cold gas efficiency than GE through use of a full slurry quench

4.7 IGCC Performance and Emissions Considerations

IGCC net power output decreases with increasing ambient temperature, but this reduction is less than that of a natural gas combined cycle (NGCC) plant. The IGCC plant auxiliary power consumption also increases slightly with the ambient temperature for ASU air compression and cooling tower fans, but this is offset by higher combustion turbine output.

The CO and NO_x emissions estimates were based on CTGs firing syngas with nitrogen dilution, but without an SCR or CO oxidation catalyst in the HRSG:

- 25 ppmvd CO in the CTG exhaust gas.
- 15 ppmvd NO_x (at 15 percent by volume O_2) in the CTG exhaust gas.

The SO_2 emissions estimate was based on a 25 ppm molar concentration of sulfur as H_2S and COS in the syngas. Sulfur removal efficiencies of greater than 99 percent are achievable for an IGCC plant processing high sulfur coal or petcoke, depending on the solvent selected. Flaring during startups, shutdowns, and upsets can result in significant SO_2 emissions. Sour gas flaring during upsets cannot be eliminated, but can be minimized by appropriate process design and operating procedures.

Syngas will flow through sulfur impregnated carbon, which is estimated to lower the syngas mercury concentration below 5 ppb by weight. Up to 40 percent of the mercury in the coal may be removed upstream of the sulfur impregnated carbon by scrubbing, which would reduce the mercury concentration at the inlet of the sulfur impregnated carbon to 30 to 42 ppb by weight. Eastman Chemical Company's coal gasification plant has used sulfur impregnated carbon beds for mercury removal since its startup in 1993. Eastman reports 90 to 95 percent mercury removal with a bed life of 18 to 24 months.

4.8 Gasification Wastewater Treatment

There are two general categories of plant wastewater:

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- Streams that contain metals from the as-received coal, referred to as gasification wastewater streams.
- Streams that do not contain these metals, referred to as balance-of-plant wastewater streams.

The gasification wastewater streams will be combined and treated separately from the balance-of-plant wastewater streams. Accurate specification of the process wastewater composition has been a problem on other operating gasification plants because of the wide variation in coal composition. The wastewater treatment design should accommodate variations in wastewater composition.

There are three basic options for treating gasification wastewater streams:

1. Open Discharge Concept, which consists of metals precipitation, followed by biological treatment to produce an effluent suitable for discharge.
2. Zero Liquid Discharge (ZLD) Concept, which consists of lime softening, followed by evaporation and crystallization to produce a solid salt for landfill disposal.
3. Discharge to a municipal sewage treatment facility or other receiving stream. This option is generally considered impractical, because the coal gasification wastewater exceeds typical pretreatment limitations.

Biological treatment of the gasification wastewater can be problematic, because the diverse contaminants are believed to be sufficiently variable so that the operation would be unreliable, which could result in violations of expected permit requirements. The open discharge system would cost approximately the same as the ZLD option and is not a proven technology in this application. The operating costs are equivalent between ZLD and open discharge systems. However, ZLD requires additional LP steam, which could otherwise be used to generate an additional 2 to 5 MW of electricity.

4.9 Acid Gas Removal Technology

Sulfur in coal is converted to H_2S and COS during gasification. The molar ratio of H_2S to COS in the raw syngas from the gasifier varies according to the gasifier type, from approximately 13 to 1 for the Shell gasifier to approximately 26 to 1 for the COP and GE gasifiers. The resulting syngas is treated to meet combustion turbine fuel and air emissions permit requirements. The requirement is for total sulfur in the clean syngas to be less than 25 ppm by weight, which is equivalent to 15 ppm by mole of COS and H_2S.

The two primary solvents considered for IGCC AGR are Selexol and methyl diethanol amine (MDEA). Selexol solvent is a mixture of dimethyl ethers of

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polyethylene glycol, $CH_3(CH_2CH_2O)_{(3\ \mathrm{to}\ 9)}CH_3$. UOP licenses Selexol technology for treating syngas from gasification. Selexol is a physical solvent. Its capacity to absorb sulfur compounds (including H_2S) and to absorb CO_2 increases with increasing pressure and decreasing temperature.

MDEA, $(HOC_2H_4)2NCH_3$, is a chemical solvent, specifically a selective amine used to remove H_2S, while leaving most of the CO_2 in the syngas. MDEA forms a chemical bond with H_2S and CO_2. MDEA's performance is nearly independent of operating pressure. Typical absorber operating temperatures with amines are between 80 and 120° F. Lower absorber operating temperatures increase both H_2S solubility and selectivity over CO_2.

The higher absorber operating pressures and higher syngas CO_2 concentrations for the COP and GE gasification processes favor the use of Selexol, while MDEA is generally favored for the Shell gasification process.

4.10 Pre-combustion Carbon Capture

In the conventional IGCC case, the gasification process produces a synthetic gas (syngas) composed primarily of a homogeneous mixture of CO and hydrogen. This fuel is provided to a combined cycle power plant, and the combustion process produces comparably the same amount of CO_2 as does a conventional coal plant.

However, by adding water-gas shift and CO_2 absorption steps, the gasification process can yield a gaseous fuel stream that is nearly carbon-free, and a CO_2-rich solvent from which CO_2 can be removed for separate sequestration or other industrial uses. The fuel stream, composed mostly of hydrogen, would be used directly as a fuel in an appropriately designed combined cycle plant.[8] The outcome is the generation of "low carbon" electric power from a low-cost fuel source.

An IGCC facility with carbon capture capability would consist of a gasification process that is closely integrated with a conventional combined cycle power plant. The base facility would consist of five major components:

- ASU
- Gasification plant
- Gas cleanup
- Water shift process
- Combined cycle power plant

[8] Hydrogen fueled CTGs are not currently commercially available.

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After particulate and acid gas removal, clean syngas is water shifted prior to combustion in the power block. The result is a gas stream composed almost entirely of hydrogen and CO_2. From that stream, up to 90 percent of the CO_2 is then removed through a stripping process by passing the gas through an absorption tower using a physical CO_2 solvent. Hydrogen can then be provided as a nearly carbon-free fuel to the CTGs. The CO_2 removed by the solvent is recovered, cooled, compressed, dried, and transported to a sequestration location.

The addition of a carbon capture process would have a significant impact on the output and heat rate of an IGCC facility. Significantly higher auxiliary loads are required for compression loads in the capture process, and thermal energy in the form of process steam is required to separate the CO_2 from the absorption solvent. Energy would also be required for captured CO_2 compression. These energy requirements would have an impact on the net plant output and net plant heat rate of the facility. In order to maintain project required net plant output, additional generation capacity would need to be installed to compensate for the increased auxiliary loads of the carbon capture process. The increase in gross plant generation would meet the carbon capture process energy requirements.

Figure 4-3 shows a pre-combustion CO_2 removal process for a typical IGCC plant.

The inclusion of carbon capture in IGCC has several significant advantages over other carbon capture options:

- The process takes place at relatively high pressures and prior to the dilution of CO_2-containing gas. With CTGs, the combustion process occurs in a very large mass of compressed air, which adds excess oxygen and large amounts of nitrogen to the flue gas. In contrast, the volume of high-pressure pre-combustion syngas flow from which CO_2 must be removed is less by two orders of magnitude than that required in the post-combustion treatment of CTG flue gas streams, significantly reducing equipment dimensions, capacities, and costs.
- CO_2 capture takes place at temperatures and pressures in which a "physical" solvent can be used, instead of the chemical solvent required in most post-combustion processes. CO_2 can be separated from physical solvents through a pressure reduction process that requires much less thermal energy than the post-combustion alternative.
- There are additional cycle efficiency benefits that may occur as more advanced CTGs are developed. At the present time, F Class technologies

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are expected to be the CTG technology developed for high hydrogen, carbon-free applications in the near term. G and H Class technologies, along with other alternative CTG cycles, offer opportunities for efficiency improvements. While none of these technologies is currently capable of burning high hydrogen fuels, industry requirements, driven by the need for carbon capture, may stimulate the required research and development to enable this application.

Pertinent technology considerations include the following:

- While IGCC plants are in operation using F Class technologies, CO_2 capture applications where the CTGs are burning virtually pure hydrogen do not exist. CTG combustion system development is required to burn hydrogen to fully support the IGCC-based carbon capture.
- There is currently a large-scale coal gasification plant with carbon capture in North Dakota in commercial operation. The Great Plains Synfuel Plant has been operating since 1983 and gasifies 16,000 tons per day of lignite to produce synthetic natural gas. CO_2 is captured as a required precursor to methanation and used for EOR. While this scale is comparable to an electric power plant, the Great Plains plant is not directly comparable to a power plant because of the additional processes that are carried out at Great Plains. This example is the most relevant commercial operating experience for this carbon capture process.

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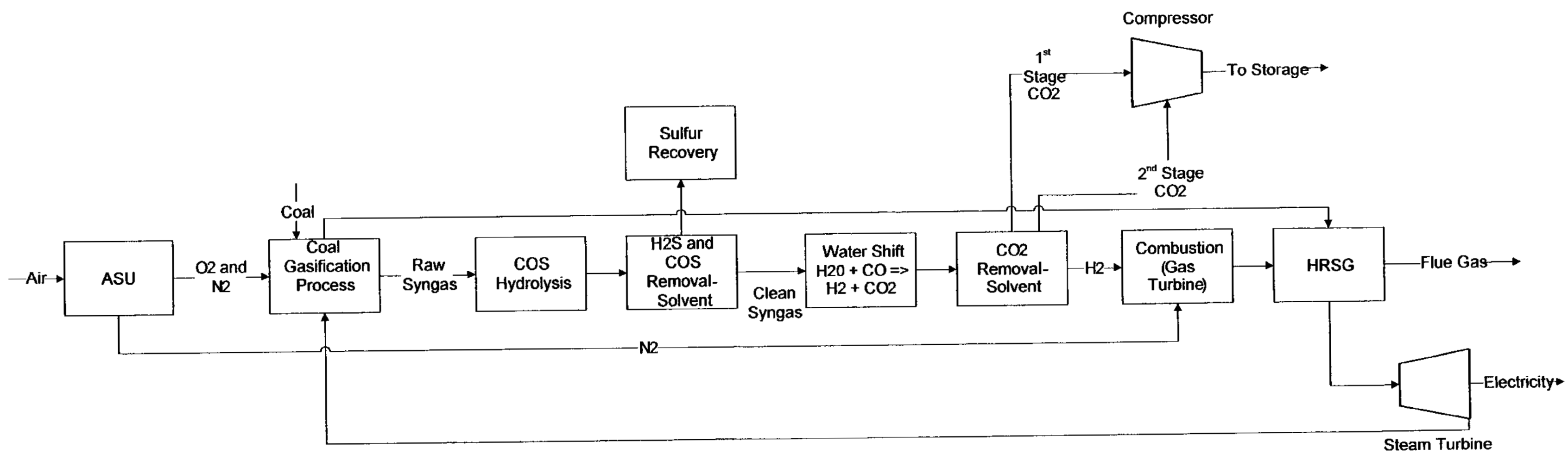

Figure 4-3. IGCC with Pre-Combustion CO_2 Capture.

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4.11 Equivalent Availability

An IGCC plant is not expected to be as reliable as a PC or CFB plant with respect to producing electricity from coal. IGCC plants without spare gasifiers are expected to achieve long-term annual equivalent availabilities in the 80 to 85 percent range versus approximately 90 percent for PC and CFB plants. Based on past experience, IGCC availability during initial startup and the first several years of operation is expected to be significantly lower than the long-term targets. This can be mitigated by firing the CTGs with backup fuel (such as natural gas or low sulfur fuel oil) however, this would reduce the fuel diversity benefit of adding coal fired generation. The equivalent availability of the combined cycle portion of an IGCC plant is expected to be above 90 percent. The equivalent availability of an IGCC plant can be increased by providing a spare gasifier. Spare gasifier economics depend on the gasifier technology, cost of backup fuel, and plant dispatch economics. The next generation of coal-fueled IGCC plants may take advantage of the lessons learned from existing operating plants, but significant startup problems should be expected.

4.11.1 First Generation IGCC Plants

Solids-related problems (erosion, pluggage, unstable flows, and syngas cooler tube leaks) caused significant gasification downtime for all four of the coal-based IGCC plants. Gasifier burner and refractory maintenance also resulted in significant downtime for the COP and GE gasifiers. For the Buggenum and Puertollano plants, CTG problems related to syngas combustion and startup air extraction were significant. Since the problems were identified, plant modifications and O&M improvements have greatly improved performance; these two plants now produce electricity at design rates and close to design efficiencies.

Estimated annual equivalent availabilities for producing electricity from coal (syngas operation) are listed in Table 4-5 for all four of the coal-based IGCC plants discussed in Section 4.5. These equivalent availabilities are for electricity production from coal or petcoke; power generation from firing the CTG on backup fuel is excluded. Gasification process availability for each of these plants was poor during the first several years of operation and continues to be a problem. The complexity and relative technological immaturity of large-scale commercial gasification processes increase opportunities for deficiencies in design, vendor-supplied equipment, construction, operation, and maintenance. During the first several years of plant operation, a number of these deficiencies were corrected, and the plant staff has optimized the plant O&M as they "move up the gasification learning curve." Design improvements are expected to be introduced on future IGCC plants, which should improve equivalent availability.

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4.11.2 Next (Second) Generation IGCC Plants

If the equivalent availability of the facility is critical to the project, the GE Quench technology with a spare gasifier is expected to provide high availability (from 85 to 90 percent), in the long term. However, as with all of the gasification technologies, in the first year, availability is expected to be around 50 percent. This would be expected to increase to the mature availability over four to five years.

Gasifiers with the water quench process have lower capital costs than gasifiers with HTHR. However, the GE Quench gasifiers have a lower efficiency power cycle because they produce LP steam instead of HP steam. Also, it is not practical to operate with a hot spare for gasifiers that use HTHR, because the HTHR requires a shutdown to switch gasifiers.

In the long-term IGCC unit forced outage rates are expected to range from 10 to 15 percent without a spare gasifier and from 5 to 10 percent with a hot spare gasifier. However, in the first year, the forced outage rate is expected to be around 45 percent. The CTG(s) can operate on backup fuel, if available, when syngas is not available. The combined cycle availability is expected to exceed 90 percent. Despite the comparatively low capital cost to add a spare Quench gasifier (roughly 60 percent of a HTHR gasifier), it appears that the prevailing sentiment in the gasification community is that the economics of a spare gasifier will be difficult to justify in most power generation applications, because of the reduced efficiency.

For many utilities, there is reduced power demand in the spring and/or fall of the year that would allow for annual planned outages. Because there are three gasifier/CTG trains, these would not typically be full plant outages, but would reduce the available output from the plant by one third for an extended time. Full plant planned outages would be required approximately every 6 years for steam turbine maintenance, similar to that required for a PC or CFB plant. The annual planned outages are a contributing factor to the lower expected equivalent availability of an IGCC plant as compared to a PC or CFB plant.

4.12 Other Commercial Entrained Bed Gasification Experience

GE Quench type gasifiers have been in commercial operation on coal or petcoke since 1983, producing syngas for chemical production. Two plants of note are the Eastman Chemical Plant in Kingsport, Tennessee, and the Ube Ammonia Plant in Japan. The syngas from these two plants is used to produce acetyl chemicals and ammonia, respectively. Kingsport has two gasifiers; one is normally operated and the other is a spare. Ube has four gasifiers; three are normally operated and one is a spare. Ube

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originally gasified crude oil, then switched to refinery residuals, then to coal, and has been gasifying a total of 1,650 tpd of petcoke since 1996. At Kingsport and Ube, an average syngas availability of 98 percent is achieved by rapid switchover to the spare gasifier, which is on hot standby, and the high level of resources (e.g., O&M) applied to the gasification process.

The Eastman Kingsport plant has occasionally been referred to as an IGCC plant. This is incorrect because it produces no power; the Eastman plant produces syngas for chemical production, with no power generation. The economics of chemical production at the Eastman facility are different from the economics of the power market. As such, a fully redundant gasifier is warranted at the Eastman facility. Eastman has made gasification one of its focus areas, as evidenced by its formation of the Eastman Gasification Services Company.

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Table 4-5. Coal/Coke-Fueled IGCC Plant Equivalent Availabilities				
IGCC Plant Location	**Nuon** Buggenum Netherlands	**Global Energy** Wabash Indiana	**TECO** Polk County Florida	**Elcogas** Puertollano Spain
Gasifier	Shell	COP E-Gas	GE HTHR	Prenflo
Net Output	252 MW	262 MW	250 MW	300 MW
Startup Year	1994	1995	1996	1998
Year after Startup	**IGCC Equivalent Availability (percent)**			
1	23	20	35	16
2	29	43	67	38
3	50	60	60	59
4	60	40	75	62
5	61	70	69	66
6	60	69	74	58
7	57	75	68	NA
8	67	78	81	
9	73	--	82	
10	78	--		
11	NA			

Note:

1. Data is based upon available information. Data reporting methodology varies somewhat between the plants.
2. Wabash Years 5 to 8 IGCC equivalent availability estimated as 95 percent of reported syngas availability.
3. Wabash availability excludes periods when the plant was shut down because of no product demand (24 percent in Year 7 - 2002 and 16 percent in Year 8 – 2003, shutdown in Year 9 - 2004 and Year 10 - 2005).

4.13 Current Announced Electric Generation Industry Activity

Major industry participants, such as AEP and Duke Energy (formerly Cinergy), are considering implementing IGCC projects. In addition, numerous smaller companies are pursuing gasification projects using state and federal grants. The more advanced,

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publicly discussed IGCC projects of which Black & Veatch is aware are shown in the table below.[9]

Table 4-6. Announced IGCC Projects Currently In Development.

Owner	Size, MW	Fuel	Technology	Location
AEP	600	Bituminous	GE	OH
AEP	600	Bituminous	GE	WV
Duke/Cinergy	600	Bituminous	GE	IN
Excelsior	600	Bituminous/ PRB	COP	MN
Southern & OUC	285	PRB	KBR	FL
Global Energy	540	Petcoke	COP	IN
Global Energy	600	Petcoke	COP	OH
ERORA	557	Bituminous	GE	IL
Energy Northwest	600	PRB/Petcoke	NA	WA
NRG Northeast	630	PRB/Petcoke	Shell	CT
NRG Northeast	630	PRB/Petcoke	Shell	NY
TECO	789	Bituminous	GE	FL
Mississippi Power CO	700	Lignite	KBR	MS

4.13.1 Summary of Proposed Projects

The development activities of the eight companies discussed in the previous subsections represent advances in the development of new IGCC plants within the United States.

Entrained flow gasification technology has been selected by six of the companies. Southern Company and OUC are moving forward with the commercial demonstration of a transport bed gasifier. Energy Northwest has not selected a vendor at this stage, but all indications are that it will be a COP, GE, or Shell entrained flow gasification technology.

All of the projects are in coastal or Midwestern locations, with elevations generally at 1,000 feet or less.

The AEP, Duke, and ERORA projects are all based upon bituminous coal. The Global Energy Lima project is based upon petcoke. Excelsior Energy and Energy Northwest anticipate a blend of fuels that would include PRB coal with petcoke. The Southern Company/OUC project is based upon 100 percent PRB coal, but is a

[9] According to December 28, 2006, press release, AEP will delay its IGCC plant development to try to reduce the estimated capital cost to be within 20 percent of market pricing of "conventional coal fired power plant."

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commercial demonstration project for a new gasification technology and the demonstration will not be complete until 2015. The fuel supply for the NRG sites is primarily coal, but could include up to 20 percent petcoke and 5 percent biomass.

4.13.2 Gasification Market Opportunities

The gasification market appears to have strong opportunities in non-electric power generation sectors. Primarily, these are production of synthetic natural gas (SNG) and coal-to liquids (CTL). Gasification is also used worldwide for ammonia production from coal.

High natural gas prices have spurred interest in SNG production. Several such projects are currently in advanced stages of development. SNG has been proven commercially by the Great Plains facility in North Dakota which has been gasifying lignite for SNG production since 1983.

For the past several years, the continuous cost increase of petroleum based transportations fuels has created a market for alternative transportation fuels. This recently emerged market, coupled with the vast coal reserves of the US, provides potential near term gasification opportunities with CTL technologies. The US Departments of Defense and Energy both have technology development initiatives that are helping drive technology deployment in the US. CTL technologies are commercially available and proven.

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5.0 Performance and Emissions Estimates

Black & Veatch developed estimates of performance for four coal-fueled generation technology options. Both performance and emissions limits were developed for single units that would be installed at a multiple unit greenfield site. Project capacity has been specified as a nominal 2,000 MW net at the FGPP plant boundary. The project required net capacity would be met by installing blocks of power to obtain the nominal 2,000 MW.

The fuel used for the performance and cost estimates consisted of a blend of Central Appalachian coal, Colombian coal, and petcoke. The PC and CFB cases utilized a blend of 40 percent Central Appalachian coal, 40 percent Colombian coal, and 20 percent petcoke, referred to as the AQCS Blend.

Technical limitations exist that restrict the amount of petcoke that can be fired in PC units. These limitations are related to the fuel characteristics of petcoke. The low volatile matter of petcoke compared to its high fixed carbon content leads to flame instability in PC furnaces. In addition, the high sulfur content of petcoke, typically in the range of 3 to 8 percent, can lead to fireside corrosion of heat transfer equipment, flue gas path ductwork, and flue gas handling equipment. The high sulfur content also adds complications in meeting SO_2 emission requirements. Because of this, petcoke is typically co-fired with coal in PC units.

The IGCC case utilized a blend of 25 percent Central Appalachian coal, 25 percent Colombian coal, and 50 percent petcoke, referred to as the IGCC Blend.

For the purposes of this evaluation, the technologies were evaluated on a consistent basis relative to one another. The technologies, plant sizes, and arrangements that were considered for this study are shown in Table 2-1.

5.1 Assumptions

Black & Veatch and FPL developed assumptions for each of the technologies. The assumptions are provided in the following subsections.

5.1.1 Overall Assumptions

For the basis of the performance estimates, the site conditions of the proposed greenfield FGPP in Glades County, Moore Haven, Florida were used. The site conditions were provided to Black & Veatch by FPL. Performance estimates were developed for both the hot day and the average day ambient conditions. Following are the overall assumptions, which were consistent among all of the technologies:

- Elevation--20 feet.

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- Ambient barometric pressure--14.67 psia.
- Hot day ambient conditions:

  Dry-bulb temperature--95° F.

  Relative humidity--50 percent.
- Average day ambient conditions:

  Dry-bulb temperature--75° F.

  Relative Humidity--60 percent.
- The assumed fuel is a blend of three different fuel supplies. The ultimate analysis of these fuels, along with the analysis of the 40/40/20 and 25/25/50 blended fuels (which were used to determine performance and cost estimates for the PC, CFB, and advanced coal technologies, respectively) is provided in Table 5-1.
- AQCS were selected to develop performance and cost estimates, based on Black & Veatch experience. Actual AQCS would be selected to comply with federal NSPS and would be subject to a BACT review.

Table 5-1. Ultimate Fuel Analysis

Fuel	Appalachian Coal	Colombian Coal	Petcoke	AQCS Blend[(1)]	IGCC Blend[(1)]
Carbon, %	70.73	64.4	79	69.85	73.28
Sulfur, %	0.91	0.67	6.75	1.98	3.77
Oxygen, %	5.65	7.73	0.78	5.51	3.74
Hydrogen, %	4.62	4.6	3.3	4.35	3.96
Nitrogen, %	1.46	1.17	1.6	1.37	1.46
Chlorine, %	0.13	0.03	0.02	0.07	0.05
Ash, %	10.05	8.9	0.5	7.68	4.99
Water, %	6.45	12.5	8	9.18	8.74
HHV, Btu/lbm	12,510	11,300	13,676	12,300	12,800

[(1)]Developed from a blend of Appalachian coal, Colombian coal, and petcoke. Blended on the basis of percent weight.

5.1.2 Degradation of Performance

Net power plant output and heat rate performance for PC, CFB and IGCC plants can be expected to decline or "degrade" with hours of operation due to factors such as blade wear, erosion, corrosion, and increased tube leakage. The magnitude of

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performance degradation is dependent upon the specific characteristics of each facility such as mode of operation, fuel characteristics, water washing and maintenance practices as well as site specific ambient conditions. A portion of this degradation is recoverable and a portion is non-recoverable.

Periodic maintenance and overhauls can recover much, but not all, of the degraded performance compared to the unit's new and clean performance. The degradation which cannot be recovered is referred to as non-recoverable degradation. Performance that is recovered by scheduled maintenance is referred to as recoverable degradation. Performance degradation can also be reported as maximum degradation, which is the reduction in performance from clean and new equipment that is expected prior to a major overhaul.

Based on Black & Veatch experience, quantifying degradation in performance is difficult because actual data is not easily documented by the users and not easily obtained from the users or from the manufacturers. Many papers contain information regarding degradation in performance but the information is heavily qualified and vaguely presented thereby limiting analysis. For this study, a maximum degradation factor, a factor used to estimate the decline in a performance parameter, was assumed for each of the technologies. A maximum degradation of 1.0 percent for both the heat rate and net power output has been assumed for the PC and CFB cases. For the IGCC case, the maximum degradation was assumed to be 2.5 percent for both the heat rate and net power output.

5.1.3 PC and CFB Coal Cycle Arrangement Assumptions

The following assumptions were common to the SPC, USCPC, and CFB cases:

- All cases would utilize a wet mechanical draft cooling tower.
- A 40/40/20 fuel blend would be used for boiler efficiency in accordance with Table 5-1.
- Condenser performance was estimated on Black & Veatch experience. The expected condenser back pressures were supplied for hot and average day ambient conditions.
- The facilities would be designed for a nominal 2,000 MW net at the FGPP plant boundary by installing multiple units. Performance estimates were developed for multiple units generating a nominal 2,000 MW net of power at the average day ambient conditions.

The following subsections provide the specific assumptions used for each of the PC and CFB cases.

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5.1.3.1 Subcritical PC.

- Single unit capacity--500 MW net.
- Subcritical STG and subcritical PC boiler.
- Tandem-compound, four-flow, 33.5 inch last-stage blade (LSB) (TC4F-33.5) STG.
- Assumed capacity factor of 92.0 percent.
- AQCS:
    - LNB, overfire air (OFA), flue gas recirculation (FGR), and SCR for NOx control.
    - Wet limestone FGD for SO_2 control.
    - Activated Carbon Injection (ACI) for further Hg control
    - Pulse jet fabric filter (PJFF) for particulate control.
    - Wet electrostatic precipitator (ESP) for control of sulfuric acid mist (SAM.)
- Auxiliary power assumed to be 9.0 percent of gross plant output.
- The auxiliary load estimate was based on using motor driven boiler feed pumps (BFPs). This estimate would decrease by 2 to 3 percent if BFPs were turbine driven.
- Throttle conditions--2,415 psia, 1,050/1,050° F.
- Seven feedwater heaters (FWHs)--Three HP, three LP, and one deaerator (DA).
- Condenser pressure for hot and average day ambient conditions assumed to be 2.9 and 2.2 in. HgA, respectively.

5.1.3.2 Ultrasupercritical PC.

- Single unit capacity--1,000 MW net.
- Supercritical STG and supercritical PC boiler.
- TC4F-40.0 STG.
- Assumed capacity factor of 92.0 percent.
- AQCS:
    - LNB, OFA, FGR, and SCR for NOx control.
    - Wet limestone FGD for SO_2 control.
    - ACI for further Hg control
    - PJFF for particulate control.
    - Wet ESP for control of SAM.
- Auxiliary power assumed to be 7.0 percent of gross plant output.

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- The auxiliary load estimate was based on using turbine driven BFPs. This estimate would increase by 2 to 3 percent if BFPs were motor driven.
- Throttle conditions--3,715 psia, 1,112/1,130° F.
- Seven FWHs--Two HP, four LP, and one DA.
- Dual condenser used. For average ambient conditions, the HP condenser pressure was assumed to be 2.1 in. HgA; LP condenser pressure was assumed to be 1.7 in. HgA.

5.1.3.3 CFB.

- Single unit capacity--2x250 MW net boilers and 1x500 MW STG.
- Subcritical STG and subcritical CFB boiler.
- TC4F-33.5 STG.
- Assumed capacity factor of 88.0 percent.
- AQCS:
  - SNCR for NOx control.
  - Boiler limestone injection and wet limestone FGD for SO_2 control.[10]
  - ACI for further Hg control
  - PJFF for particulate control.
- Auxiliary power assumed to be 10.0 percent of gross plant output.
- The auxiliary load estimate was based on using motor driven boiler feed pumps (BFPs). This estimate would decrease by 2 to 3 percent if BFPs were turbine driven.
- Throttle conditions--2,415 psia, 1,050/1,050° F.
- Seven FWHs--Two HP, four LP, and one DA.
- Condenser pressure for hot and average day ambient conditions assumed to be 2.9 and 2.2 in. HgA, respectively.

5.1.4 IGCC Cycle Arrangement Assumptions

IGCC application has different issues that need to be considered. Unlike PC and CFB units, an IGCC cannot be sized to match a selected net plant output. The constraints are similar to that of a conventional natural gas fired simple or combined cycle unit. CTGs come in discrete sizes and are much more sensitive to changes in elevation and ambient temperature than thermal plants.

Currently, the most economic IGCC configurations are based upon state-of-the-art conventional "F" class CTGs modified to fire syngas. The GE 7FB and the Siemens SPG

[10] Wet FGD was applied to the CFB case to attain a comparable SO_2 emission to allow comparison with the PC options.

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SGT6-5000F CTGs are the most likely models to be incorporated in an IGCC plant. At International Organization for Standardization (ISO) conditions (sea level, 59° F, 60 percent relative humidity), these CTGS are rated at 232 MW when firing syngas. A single 7FB or SGT6-5000F in an IGCC configuration produces a nominal 300 MW net at ISO conditions. Therefore, a 3-on-1 IGCC configuration would produce a nominal 900 MW net at ISO conditions. The net output will vary somewhat depending upon the gasification technology employed, as well as the degree of integration.

The intent of the study was not to compare all of the gasification technologies against the PC and CFB options. To perform this study a gasifier technology choice needed to be made by Black & Veatch. Because of the fuel and location of the project, Black & Veatch selected GE Radiant as being representative of the commercial gasification technologies available. Based on experience, it was Black & Veatch's opinion that there would be not sufficient difference in cost and performance of one technology over another that would cause IGCC to be positively or negatively affected in the overall technology comparison. Black & Veatch did not select the GE Quench technology because GE currently prefers the Radiant in IGCC applications.

The following were assumed:

- Fuel supply used for gasifier feedstock in accordance with Table 5-1.
- Capacity factor of 80.0 percent.
- Six GE Radiant gasifiers.
- Six GE 7321(FB) CTGs with syngas combustors.
- TC2F-33.5 STG.
- Three-pressure reheat HRSG with duct firing.
- AQCS:
    - Selexol AGR.
    - Nitrogen diluent and syngas saturation for NO_x control.
    - Candle filter.
    - Sulfided carbon bed for Hg adsorption.
- 100 percent syngas fuel -- no backup fuel will be provided.
- Inlet air evaporative cooling above 59° F.
- Wet deaerating condenser.
- Throttle conditions--1,565 psia/1,000° F/1,000° F.
- For this evaluation, the STG was designed for normal pressure at average day conditions during syngas operation.

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5.2 Performance Estimates

Full-load performance estimates for each of the PC and CFB cases are presented in Table 5-2. Full-load performance estimates for the IGCC cases are presented in Table 5-3. The IGCC case is presented in a separate table from the PC and CFB cases because IGCC has some unique performance parameters.

5.2.1 PC and CFB Cases

Full-load performance estimates were developed for each of the specific PC and CFB cases. A total of six performances cases were run (two for each technology), consisting of performance estimates for the hot day and average day ambient conditions. Each of the cases was evaluated on a consistent basis to show the effects of technology selection on project performance. The performance estimates were generated for single units that would be installed at a multiple unit greenfield site.

5.2.2 IGCC Cases

Full-load performance estimates were developed for the IGCC cases. A total of two performance cases were run, one at hot day and one at average day ambient conditions. The IGCC case was evaluated on a consistent basis with the PC and CFB cases with respect to site and ambient conditions to show the effects of technology selection on project performance.

5.3 Emissions Estimates

For the purpose of estimating capital and O&M costs for AQCS, probable full-load emission limits were provided to Black & Veatch by FPL. These limits will be subject to later BACT review and are not intended to define performance requirements. Emissions estimates for the PC, CFB, and IGCC cases are summarized in Table 5-4. The emissions rates in the tables are expressed in lb/MBtu of heat input from the fuel. Emissions estimates should only be used for the screening-level evaluation. Final permit levels may vary on a case-by-case basis. Estimates of CO_2 emissions are shown in Table 5-5.

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Table 5-2. PC and CFB Coal Performance Estimates, per Unit

Technology Fuel	SPC AQCS Blend	USCPC AQCS Blend	CFB AQCS Blend
Performance on Average Ambient Day at 20 ft ASML, Clean and New Equipment			
Steam Conditions, psia/° F/° F	2,415/1,050/1,050	3,715/1,112/1,130	2,415/1,050/1,050
Fuel Input, MBtu/h	4,600	8,480	4,730
Boiler Efficiency (HHV), percent	88.9	88.9	87.0
Heat to Steam (HHV), MBtu/h	4,090	7,545	4,200
Gross Single Unit Output, MW	550	1,054	556
Total Auxiliary Load, MW	50	74	59
Net Single Unit Output, MW	500	980	497
Gross Turbine Heat Rate, Btu/kWh	7,450	7,140	7,540
Condenser Pressure, in. HgA	2.2	2.1/1.7	2.2
NPHR (HHV), Btu/kWh	9,210	8,660	9,510
Net Plant Efficiency (HHV), percent	37.0	39.4	35.9
Performance on Hot Day at 20 ft ASML, Clean and New Equipment			
Net Single Unit Output, MW	494	976	491
NPHR (HHV), Btu/kWh	9,340	8,690	9,640
Performance On Average Ambient Day at 20 ft ASML, Maximum Degradation (1.0% heat rate and 1.0% net plant output)			
Net Single Unit Output, MW	495	970	492
NPHR (HHV), Btu/kWh	9,300	8,750	9,610

Note:
USCPC option has dual condensers, therefore both pressures are listed.
No margins are applied to performance estimates.

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Table 5-3. GE Radiant IGCC Performance Estimates, per Unit

Fuel	IGCC Blend
Combined Cycle Configuration	3 x 1 GE 7FB
Performance on Average Day at 20 ft ASML, Clean and New Equipment	
Coal to Gasifiers, MBtu/h	8,400
Gasifier Cold Gas Efficiency (Clean Syngas HHV/Coal HHVx100)	74
CTG Heat Rate (LHV), Btu/kWh	8,370
CTG(s) Gross Power, MW	687
Steam Turbine Gross Power, MW	451
Syngas Expander Power, MW	5
Total Gross Power, MW	1,143
Aux. Power Consumption, MW	203
Net Power, MW	940
Net Plant Heat Rate (HHV), Btu/kWh	8,990
Net Plant Efficiency (HHV), Btu/kWh	38.0
Performance on Hot Day at 20 ft ASML, Clean and New Equipment	
Net Power, MW	902
Net Plant Heat Rate (HHV), Btu/kWh	9,360
Performance on Average Day at 20 ft ASML, Maximum Degradation (2.5% heat rate and 2.5% net power output)	
Net Power, MW	917
Net Plant Heat Rate (HHV), Btu/kWh	9,215

Notes:
Based on publicly available data from technology vendor.
No margins are applied to performance estimates.

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Table 5-4. Probable Air Emissions Limits

Emissions	SPC	USCPC	CFB	IGCC
SO_2, lb/MBtu	0.04	0.04	0.04	0.015[a]
NO_x, lb/MBtu	0.05	0.05	0.07	0.06
PM_{10}, lb/MBtu, filterable	0.013	0.013	0.015	0.014
SAM, lb/MBtu	0.004	0.004	0.004	NA[b]
Hg, lb/MWh	9.9×10^{-6}	9.9×10^{-6}	10×10^{-6}	20×10^{-6}

Notes:

All emission limits are on a HHV basis.

[a] Probable emission limit under continuous operation. Normalized annual emission rate considering four start-ups and shutdowns could reach 0.038 lb/MBtu.[11]

[b] If SO_2 is properly controlled. H_2SO_4 emissions estimated at 5.6 lb/hr.

Table 5-5. Probable Air Emissions Limits

Emissions	SPC	USCPC	CFB	IGCC
CO_2, lb/MBtu	208.1	208.1	208.1	209.8
CO_2, lb/MWh	1,935	1,821	1,989	1,933

Notes:

All emission limits are on a HHV basis.

Values are calculated based on fuel composition.

[11] Based on data presented in the Permit to Construct Application submitted on September 29, 2006, by AEP for the Mountaineer IGCC project.

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6.0 Cost Estimates

This section provides representative high-level cost estimates consisting of the following:

- Overnight capital cost estimates presented on an EPC basis exclusive of Owner's costs.
- O&M costs as fixed O&M costs and variable nonfuel O&M costs.

The cost estimates presented in this section were developed assuming that multiple units would be constructed at a single greenfield site. Multiple units will be constructed to obtain 2,000 MW of net nominal capacity at a single facility. Therefore, the cost estimates will be reflective of the economies of scale savings that occur for multiple unit facilities.

6.1 Capital Costs

Market-based overnight capital cost estimates for the four coal technologies were estimated. The estimates are expressed in 2006 US dollars and were developed using the assumptions listed in Section 5.1. An EPC cost basis was utilized exclusive of Owner's costs. Typically, the scope of work for EPC costs is the base plant, which is defined as being "within the fence" with distinct boundaries and terminal points. The values presented are believed to be reasonable for today's market. More importantly, the EPC costs were developed in a consistent manner and are reasonable relative to one another.

The cost estimate includes estimated costs for equipment and materials, construction labor, engineering services, construction management, indirects, and other costs on an overnight basis. The estimates were based on Black & Veatch proprietary estimating templates and experience. These estimates are screening-level estimates prepared for the purposes of project screening, resource planning, comparison of alternative technologies, etc., and as such are expected to be in the range of ±25 percent. The cost estimates were made using consistent methodology between technologies, so while the absolute cost estimates are expected to vary within a band of accuracy, the relative accuracy between technologies is better. The information is consistent with recent experience and market conditions, but as demonstrated in the last few years, the market is dynamic and unpredictable. Power plant costs will be subject to continued volatility in the future, and the estimates in this report should be considered primarily for comparative purposes. The AQCS for each technology were selected to meet the proposed emissions levels for criteria pollutants including NO_x, SO_2, Hg, and PM_{10}.

Given the level of uncertainty with developing screening-level capital costs, particularly for technologies with a limited database of actual installed costs, it is

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recommended that sensitivity evaluations be conducted to determine the competitiveness of a technology that appears cost-effective under base case assumptions.

6.2 Owner's Costs

The sum of the EPC capital cost and the Owner's cost equals the total project cost or the total capital requirement for the project. Typical Owner's costs that may apply are listed in Table 6-1. These costs are not usually included in the EPC estimate and should be considered by the project developer to determine the total capital requirement for the project. Owner's cost items include costs for "outside the fence" physical assets, project development, and financing costs. Interconnection costs can be major cost contributors to a project and should be evaluated in greater detail during the site selection. The order of magnitude of these costs is project-specific and can vary significantly, depending upon technology and project-unique requirements.

For a screening-level analysis, the Owner's cost, exclusive of interest during construction (IDC), can be estimated as a percentage of the EPC cost. Typically, based on actual project financial data, Owner's costs exclusive of IDC and escalation have been found to be in the range of 15 to 20 percent of the EPC cost for PC and CFB projects.

Additional considerations are merited for IGCC. Without a historical basis, Black & Veatch has added an allowance of 6 percent of the EPC cost. This contingency is in addition to the 15 to 20 percent Owner's costs, exclusive of IDC, and would cover the unexpected repairs and modifications needed during the initial years of operation. To attain high availability, it is assumed that the Owner would have to aggressively correct deficiencies and implement enhancements as they were identified. Some of the costs for correcting deficiencies can be recovered from the EPC contractor, but the Owner should expect to have significant initial operating costs that will not be reimbursed by the EPC contractor. Depending on the contracting arrangement and guarantees obtained, some of this responsibility/liability might be accepted by the EPC contractor, but it can be assumed that it would result in an equivalent price increase by the EPC contractor to assume the additional risk.

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Table 6-1. Potential Owner's Costs

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:
- AQCS materials, supplies, and parts
- Acid gas treating materials, supplies, and parts
- Combustion and steam turbine materials, supplies, and parts
- HRSG, gasifier and/or boiler materials, supplies, and parts
- Balance-of-plant equipment/tools
- Rolling stock
- Plant furnishings and supplies

Owner's Project Management:
- Preparation of bid documents and selection of contractors 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
- 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
- Supply of trained operators to support equipment testing and commissioning

Taxes/Advisory Fees/Legal:
- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Power Purchase Agreement (PPA)
  - Interconnect agreements
  - Contracts--procurement and 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:
- Financial advisor, lender's legal, market analyst, and engineer
- Development of financing sufficient to meet project obligations or obtaining alternate sources of lending
- Interest during construction
- Loan administration and commitment fees
- Debt service reserve fund

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6.3 Nonfuel O&M Costs

Preliminary estimates of O&M expenses for the technologies of interest were developed. The O&M estimates were derived from other detailed estimates developed by Black & Veatch and are based on vendor estimates and recommendations, actual performance information gathered from in-service units, and representative costs for staffing, materials, and supplies. Plant staffing was assumed to provide operating and routine maintenance. The estimated O&M costs were developed using the assumptions listed for each of the cases in Section 5.1. Additional assumptions specific to O&M cost development are as follows:

- 6 year cycle between major STG overhauls.
- 2 year cycle between major PC boiler overhaul.
- 1 year cycle between major CFB boiler overhaul.
- 1 year cycle between major IGCC gasification overhaul
- Average plant technician salary would be $62,900/year, plus a 40 percent burden rate.
- Staff supplies and material were estimated to be 10 percent of staff salary.
- Insurance and property taxes are not included.
- Estimated employee training cost and incentive pay/bonuses are included.
- The variable O&M analysis was based on a repeating maintenance schedule for the boiler and STG and considers replacement and refurbishment costs.
- The fixed O&M analysis assumes that the fixed costs would remain constant over the life of the plant.
- Costs of major consumables are listed in Table 6-2.

Table 6-2. O&M Consumable Assumptions, $2006

Waste Disposal Cost	$/ton	6
Limestone Cost	$/ton	15
Lime Cost	$/ton	60
Ammonia Cost	$/ton	300
Urea Cost	$/ton	315
SCR Catalyst Cost	$/m^3	5,400
Powder Activated Carbon	$/lb	0.50

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6.4 Economies of Scale

6.4.1 Multiple Unit Sites

The benefit of economies of scale can be realized through facilities with high output and/or through multiple unit facilities. This assumes that the multiple units are duplicates of each other.

In most cases, a coal plant is initially designed for multiple units. Usually, the design calls for a minimum of two identical units, but can include three or four units. Capital intensive projects, such as PC units, realize substantial savings when the site includes multiple units. The savings will vary depending on the number of units installed at the site and the degree of interconnections and commonality of supporting systems.

The cost of the first unit on a two-unit site will be slightly higher than the cost for a single-unit site. This is because of the increased capacity of common systems or level of equipment redundancy and increased infrastructure. The increase in first-unit cost is expected to be in the range of 6 to 8 percent.

For a two-unit site, assuming identical units constructed within 1 to 2 years of each other, the second unit cost will be in the range of 75 to 80 percent of the first unit. A four-unit facility would typically be designed as two, two-unit plants. These economies of scale factors apply to EPC cost estimates that are exclusive of Owner's costs. The initial design of the plant should consider the economies of scale based on multiple units and/or unit size. The use of multiple identical units constructed in reasonable sequence will result in the greatest savings.

6.4.2 Economies of Scale Based on Unit Size

The cost per unit of output ($/kW) decreases as the output of the unit increases. This is mainly because there are many items (of cost) that are independent (in varying degrees) of unit size. Some examples include engineering for project design and manufacturing, manufacturing and construction management, distributed control system (DCS), instrumentation, plant infrastructure, project development cost, etc. Other independent costs, such as the Owner's costs (which were not estimated in this study), make the economies of scale based on unit size more significant.

6.5 Recent Experience

The estimated EPC costs were reviewed and adjusted according to recent conceptual-level cost estimates and Black & Veatch experience on actual projects. Black & Veatch has experienced substantial increases in costs over the past year. As an example, Black & Veatch had a cxperience with a boiler original equipment manufacturer (OEM) who increased a boiler quotation by about 20 percent. Additionally,

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it should be noted that AQCS prices have been increasing dramatically, and all AQCS OEMs are experiencing increased business. Costs continue to rise because of labor and material cost increases as well as market demand. For the present, the market has shifted to a seller's market. These cost increases apply to all of the technologies considered in this report.

6.6 Preliminary Cost Estimates

Preliminary capital cost estimates for the PC, CFB, and IGCC cases are presented in Table 6-3. These cost estimates were developed on an EPC basis and do not include Owner's costs. Nonfuel O&M cost estimates, including fixed costs and variable costs, are shown in Table 6-4. Both the capital and O&M costs estimates for the PC and CFB cases were developed on the basis of a multiple unit facility, so as to obtain nominal 2,000 MW of electrical power generation at a single facility.

Table 6-3. Capital Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
EPC Cost, 2006$MM	3,078	2,646	3,240	3,541
Unit EPC Cost, 2006$/kW	**1,540**	**1,350**	**1,630**	**1,880**
Escalation to 2012$	490	421	516	564
Subtotal - EPC Cost 2012$	*3,568*	*3,067*	*3,756*	*4,105*
Owner's Costs, 2012$	1,218	1,153	1,236	1,411
IDC, 2012$	1,063	914	1,119	1,223
Project Cost, 2012$	*5,849*	*5,134*	*6,111*	*6,739*
Unit EPC Cost, 2012$/kW	**2,925**	**2,619**	**3,074**	**3,585**

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Table 6-4. O&M Cost Estimates

Technology	SPC	USCPC	CFB	IGCC
Net Single Unit Output, MW	500	980	497	940
Net Multiple Unit Output, MW	2,000	1,960	1,988	1,880
Capacity Factor, percent	92.0	92.0	88.0	80.0
Annual Generation, GWh	16,100	15,800	15,300	13,200
Fixed Costs, 2006$, (1,000s)	35,780	27,500	38,800	47,810
Fixed Costs, 2006$/kW	17.89	14.03	19.54	25.43
Variable Costs, 2006$ (1,000s)	45,130	47,500	68,000	80,120
Variable Costs, 2006$/MWh	2.94	2.86	4.44	6.07
Fixed Costs, 2012$, (1,000s)	41,480	31,870	45,050	55,420
Fixed Costs, 2012$/kW	20.74	16.26	22.66	29.48
Variable Costs, 2012$ (1,000s)	54,900	52,300	78,600	92,930
Variable Costs, 2012$/MWh	3.41	3.31	5.14	7.04

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7.0 Economic Analysis

A busbar analysis was developed to compare the four technologies. The economic criteria, summary of inputs, and results are presented in this section.

7.1 Economic Criteria

The economic criteria utilized for the busbar analysis are summarized in Table 7-1. Estimated forecasts for the delivered price of the AQCS and IGCC fuel blends to the proposed FGPP throughout the life of the project were provided by FPL and are shown in Table 7-2.

Table 7-1. Economic Criteria

Parameter	
Owner's IGCC Risk Contingency, Percent of EPC Cost, percent	6.0
General Inflation, percent	3.0
Present Worth Discount Rate, percent	8.82
Levelized Fixed Charge Rate, percent	N/A [1]
First year CO_2 Allowance Credit - Mild, $/ton 2012 [2]	7
First year CO_2 Allowance Credit - Stringent, $/ton 2012 [3]	14
First year NO_x Allowance Credit, $/ton 2012 [3]	1,676
First year SO_2 Allowance Credit, $/ton 2012 [3]	1,399
First year Hg Allowance Credit, $/lb 2012 [3]	25,459

Note:
[1] LFCR is not used in the economic analysis. Instead, an annual revenue requirement provided by FPL is applied to capital expenditures.
[2] From 4 pollutant 2005 Bingaman Proposal – Escalated at 2.5 percent after forecast period.
[3] From 4 pollutant 2005 McCain Proposal – Escalated at 2.5 percent after forecast period.
[4] From 3 pollutant proposal – Escalated at 2.5 percent after forecast period.

The busbar costs were calculated starting in 2012 and extending over the previously described economic durations. The busbar costs are presented in 2012$ assuming escalation of annual costs over the life of the project.

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Year	AQCS Blend[1]	IGCC Blend[1]
2012	2.90	2.68
2013	2.97	2.76
2014	3.04	2.83
2015	3.10	2.89
2016	3.17	2.95
2017	3.25	3.01
2018	3.32	3.07
2019	3.40	3.14
2020	3.49	3.21
2021	3.57	3.29
2022	3.66	3.36
2023	3.76	3.45
2024	3.85	3.53
2025	3.95	3.62
2026	4.04	3.70
2027	4.14	3.80
2028	4.24	3.89
2029	4.34	3.98
2030	4.45	4.08
2031	4.56	4.18
2032	4.68	4.29
2033	4.80	4.40
2034	4.92	4.51
2035	5.05	4.63
2036	5.19	4.75
2037	5.33	4.87
2038	5.49	5.02
2039	5.65	5.17
2040	5.82	5.33

Table 7-2. Fuel Forecasts ($/MBtu, delivered)

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Table 7-2. Fuel Forecasts ($/MBtu, delivered)

Year	AQCS Blend[1]	IGCC Blend[1]
2041	6.00	5.49
2042	6.18	5.65
2043	6.36	5.82
2044	6.55	5.99
2045	6.75	6.17
2046	6.95	6.36
2047	7.16	6.55
2048	7.37	6.75
2049	7.60	6.95
2050	7.82	7.16
2051	8.06	7.37

[1] Developed from blends of Appalachian coal, Colombian coal, and petcoke. Blending calculated by %weight.

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7.2 Busbar Analysis

A levelized busbar cost analysis was performed using several sets of data. These include:

- Economic criteria provided by FPL, shown in Table 7-1.
- Fuel forecasts provided by FPL, shown in Table 7-2.
- Performance estimates for the PC, CFB, and IGCC cases listed in Table 5-2 and Table 5-3.
- EPC capital cost estimates listed in Table 6-3.
- O&M cost estimates listed in Table 6-4.

The PC and CFB cases were run with a 40 year book and 20 year tax life. The IGCC case was run with a 25 year book and 20 year tax life.

Performance was based on the annual average day conditions. The capacity factors for the PC, CFB, and IGCC units were assumed to be 92, 88, and 80 percent, respectively.

The IGCC analysis has not supplemented the capacity factor by assuming operation on natural gas to bring the capacity factor up to the same levels as the PC and CFB units. IGCC availability will be lower in the earlier years of operation as the operators learn how to run the plant and design modifications are made. The first year availability is expected to be around 50 percent. The base analysis has not reflected the ramp up from 50 to 80 percent in IGCC equivalent availability that is expected over the first five years of operation, and instead assumes that IGCC equivalent availability is 80 percent from the outset. This assumption is favorable for IGCC by overestimating annual generation.

A summary of the inputs consisting of estimates of performance and capital and O&M costs for each of the technologies used in the busbar analysis is provided in Table 7-3. Several cases were run:

- Degraded performance at average ambient conditions with no emissions allowance cost included.
- New and clean performance at average ambient conditions with no emissions allowance cost included.
- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, and Hg. Emission allowance costs were estimated by multiplying a forecasted allowance cost by the total annual emissions of each pollutant based on the assumed control limits minus annual emission allocations for FGPP.
- New and clean performance at average ambient conditions with emissions allowance costs included for NO_x, SO_2, and Hg.

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- Degraded performance at average ambient conditions with emissions allowance cost included for NO_x, SO_2, Hg, and CO_2 using the Bingaman carbon tax estimate. No carbon capture was included.

Estimates of emissions allowance costs for NO_x, SO_2, Hg and the two CO_2 cases were taken from a report prepared by ICF International.[12] The costs are forecast through 2024. This study escalates the 2024 values by 2.5 percent annually through the last year of the economic analysis for each generation technology.

The results of the busbar analysis are provided in Table 7-4. From the analysis, the USCPC unit is the most cost effective technology. The analysis was run with the costs of emissions allowances included and excluded from the annual operating costs. In all instances, the USCPC is the most cost effective technology.

Table 7-3. Summary of Busbar Model Inputs

Technology	SPC	USCPC	CFB	IGCC
Cost Estimates				
EPC Capital Cost, 2006 $1,000	$3,078,000	$2,646,000	3,240,000	$3,541,000
Project Cost, Installed, 2012 $1,000	$5,850,000	$5,135,000	$6,111,000	$6,740,000
Fixed O&M, 2006 $/kW	17.89	14.03	19.54	$25.43
Variable O&M, 2006 $/MWh	2.94	2.86	4.44	$6.07
Fixed O&M, 2012 $/kW	20.74	16.26	22.66	$29.48
Variable O&M, 2012 $/MWh	3.41	3.33	5.14	$7.04
Average Day Performance				
New & Clean NPO, kW	2,000,000	1,960,000	1,988,000	1,880,000
Degraded NPO, kW	1,980,000	1,940,000	1,968,000	1,834,000
New & Clean NPHR, Btu/kWh (HHV)	9,210	8,660	9,510	8,990
Degraded NPHR, Btu/kWh (HHV)	9,300	8,750	9,610	9,215
Capacity Factor	92%	92%	88%	80%

[12] "U.S. Emission and Fuel Markets Outlook 2006," ICF International, Winter 2006/2007.

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Table 7-4. Busbar Cost Analysis Results, ¢/kWh

Case	SPC	USCPC	CFB	IGCC
Degraded performance, w/o emissions	9.56	8.63	10.54	12.69
New and clean performance, w/o emissions	9.47	8.54	10.43	12.38
Degraded performance, w/ emissions	9.68	8.74	10.66	12.81
New and clean performance, w/ emissions	9.58	8.65	10.56	12.50
Degraded performance, w/ emissions including CO_2	10.96	9.94	11.99	14.00

Note: Results were based on economic criteria from Table 7-1, fuel forecasts from Table 7-2, and the inputs from Table 7-3. These results are based on the maximum assumed capacity factors at average ambient conditions. Results are based on using 2012 cost estimates.

Three charts are provided to illustrate sensitivities of the busbar cost analysis. Figure 7-1 shows a breakdown of the components of the base case busbar cost without emissions allowances. It is seen that fuel and capital requirements make up the majority of the total busbar costs. Variations in these two cost categories will have the largest effect on the estimated busbar cost for any technology. Figures 7-2 and 7-3 are similar to Figure 7-1, but show the affect of adding the cost of emissions allowances. Figure 7-2 shows the incremental cost of adding allowance costs for NO_x, SO_2 and Hg. It can be seen that variations in emissions translate to minimal cost variations between the technologies. Figure 7-3 shows that the affect of adding CO_2 allowances (using the Bingaman case with no carbon capture). The carbon tax causes a noticeable increase to the absolute busbar costs, but because CO_2 emissions are relatively equal between technologies there is no effect on the rank order of busbar costs.

A sensitivity case was run that included potential costs of carbon capture. There have been many studies performed by other parties to quantify the cost of capturing carbon. Brief descriptions of available technologies were provided in Sections 3 and 4 of the report. Because study of the potential cost of carbon capture was not a focus of this effort, high level assessments have been made to provide a representation of the cost of carbon capture and show the relative effect of this added cost on the economic comparison between technologies.

A review of recent literature, including the US EPA "Environmental Footprints and Cost of Coal-Based Integrated Gasification and Pulverized Coal Technologies" and the Alstom chilled ammonia position paper indicates a probable range of carbon capture as shown in Table 7-5.

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Case	Low Cost	High Cost
Post-Combustion	20	40
Pre-Combustion	20	30

Table 7-5. Probable Carbon Capture Costs, 2006$/Avoided Ton CO_2.

The cost range for pre-combustion is representative of current literature values published by technology neutral sources. The cost range for post-combustion uses Alstom's cost projection for their technology to establish the low value and then makes an assumption that the commercial cost could be 100 percent more for the high value. Estimated costs for other post combustion carbon capture systems published in other studies are higher than those published for this unique Alstom technology.

When these costs are added to the busbar cost analysis, with adjustments for output and net plant heat rate made as needed, the percentage increase of busbar cost over the base case analysis for new & clean conditions are as shown in Table 7-6.

Table 7-6. Probable Busbar Percentage Cost Increase with Carbon Capture and Emissions Allowances.

Case	Low Cost	High Cost
SPC	20	30
USCPC	20	30
CFB	20	30
IGCC	20	25

Note:
Assumes 90 percent carbon capture for conditions at average ambient temperatures compared to case with no emissions allowance costs. Includes emissions allowances for NO_x, SO_2, Hg, and emitted CO_2 using the 2005 McCain cost proposal.

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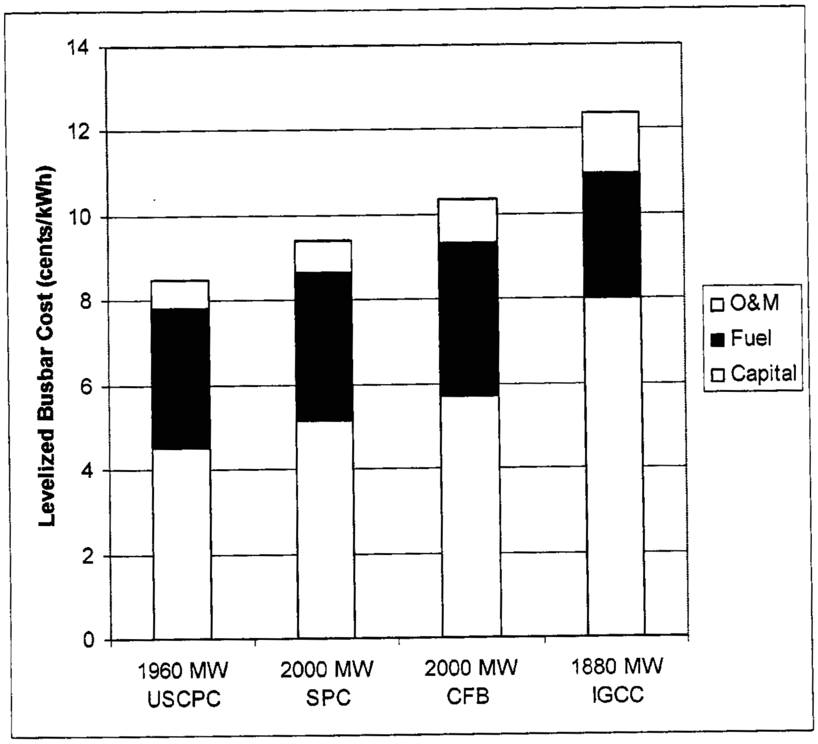

Figure 7-1. Busbar Cost Component Analysis without Emissions

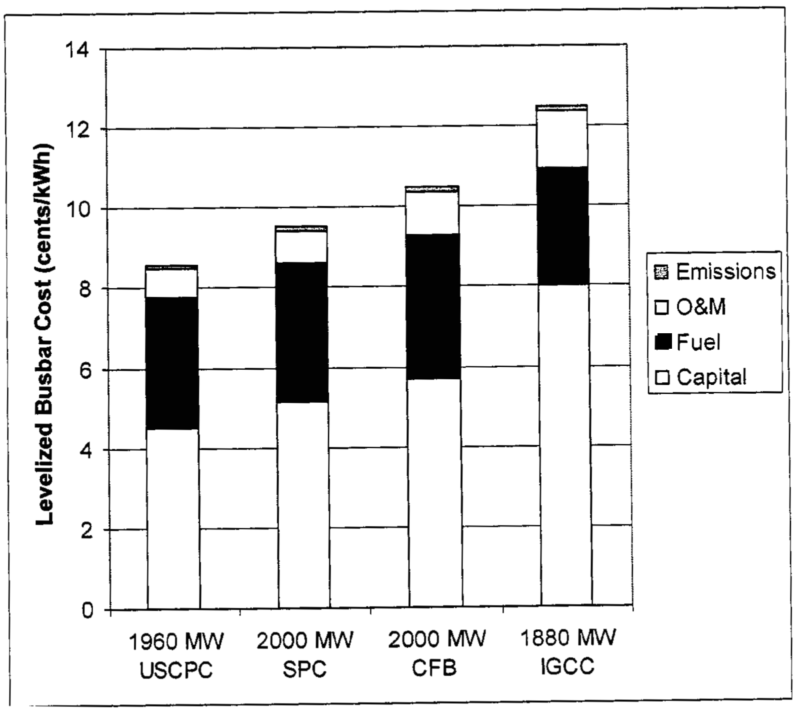

Figure 7-2. Busbar Cost Component Analysis with Emissions

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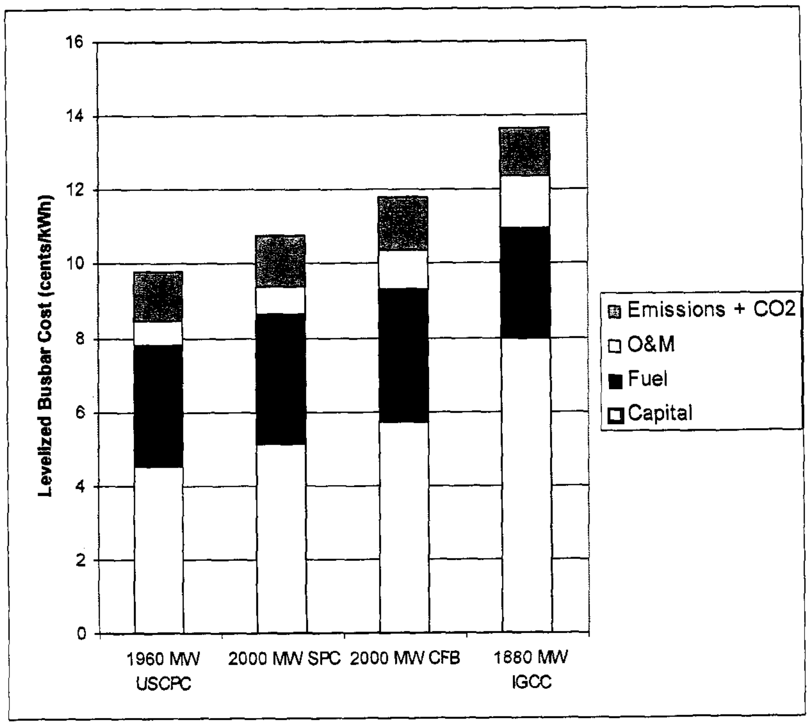

Figure 7-3. Busbar Cost Component Analysis with CO_2

A sensitivity analysis was run to show the effect variations in capacity factor have on economic analysis outputs. Figures 7-4 and 7-5 show the variations in busbar cost in cents per unit of generation (¢/kWh) and net levelized annual cost in dollars per unit of net plant output ($/kW) versus annual capacity factor. The sensitivity analysis was run over a range of capacity factors, from 40 percent to the maximum for each technology. The net plant heat rate was kept constant for all capacity factors, assuming full load operation. It can be seen that while all of the technologies have dramatic changes in busbar and net levelized annual cost across the range of capacity factors, the rank order of costs does not vary with capacity factor.

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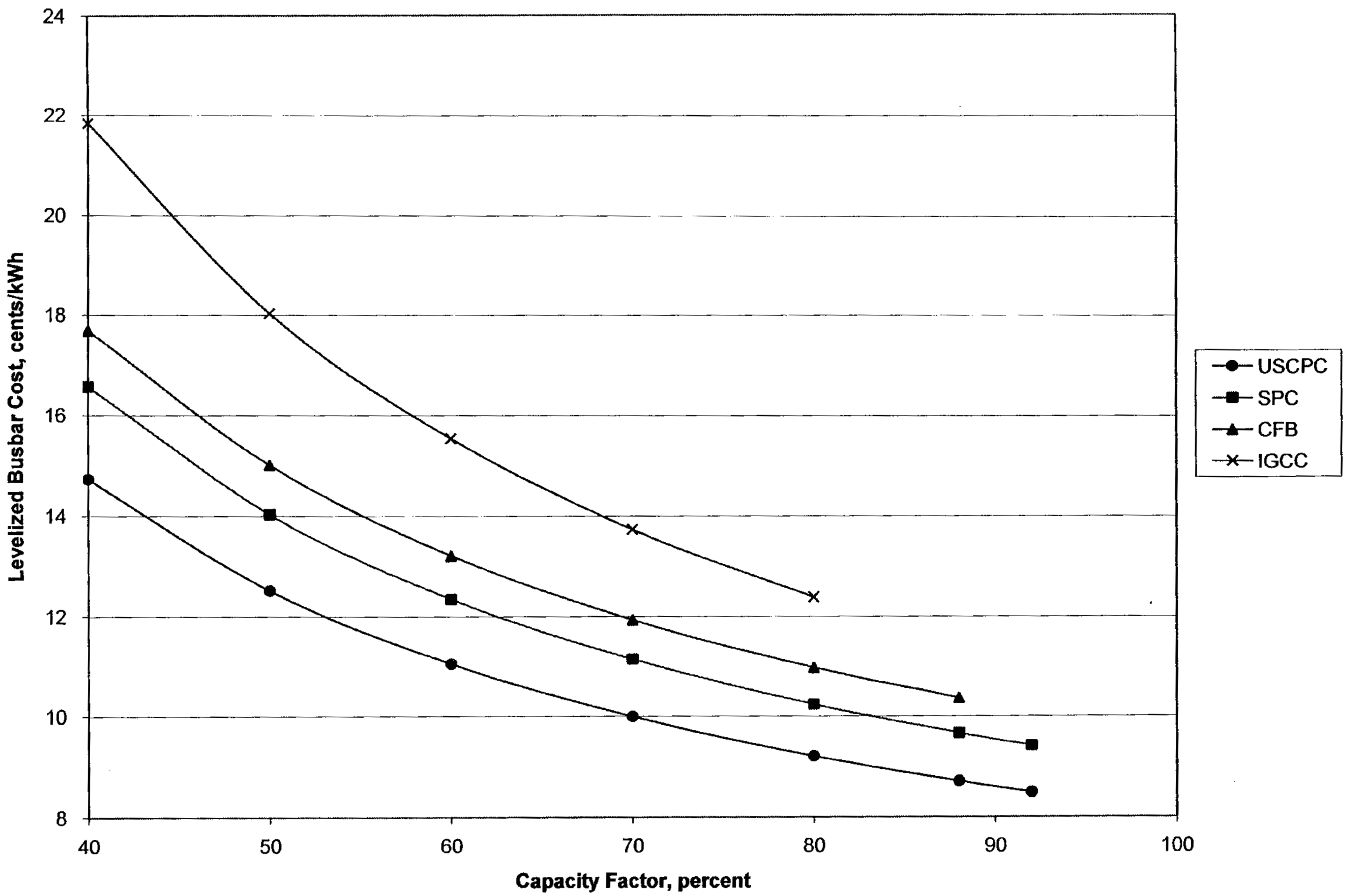

Figure 7-4. Busbar Cost Variation with Capacity Factor

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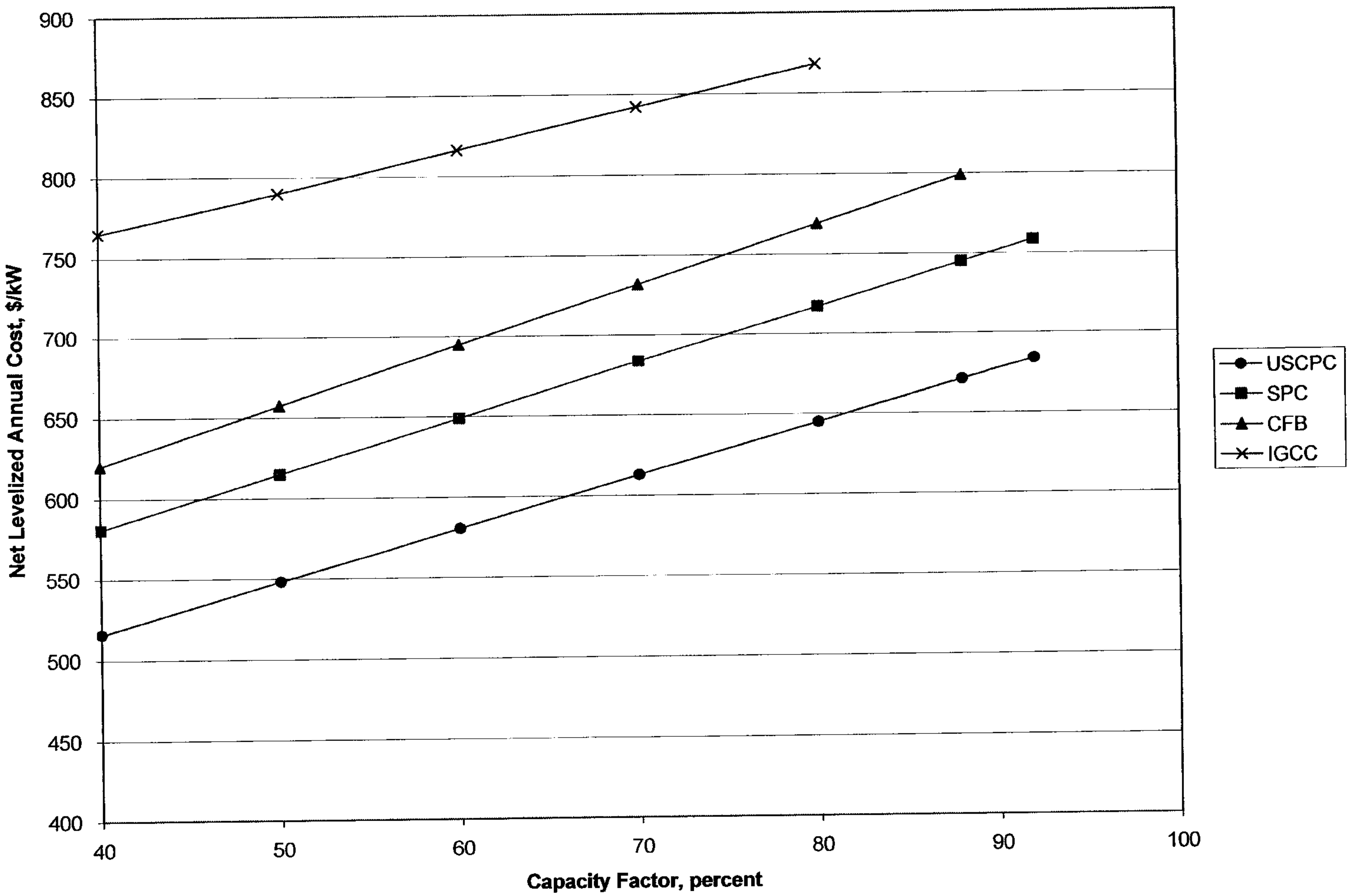

Figure 7-5. Net Levelized Annual Cost Variation with Capacity Factor

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8.0 Conclusions

This study made a comparison of performance and cost of four commercially available coal-fired power generation technologies. These were USPC, subcritical PC, CFB and IGCC. The estimates for performance were made using publicly available data and engineering data that has been collected by Black & Veatch and FPL. The results of the study are not intended to be absolute for any given technology but rather are intended to be accurate relative from one technology to another.

This study addresses technology risks known or assumed for each type of plant. Clearly PC plants are commercial and have been a dependable generation technology for years. The advancement of operation at ultrasupercritical steam conditions is somewhat new, but has been commercially demonstrated and proven around the world. CFB is also proven its dependability over the past two decades and is considered a mature technology. IGCC has been demonstrated on a commercial scale for over ten years. A second round of commercial scale IGCC plants is being planned currently. Many utilities will reserve decisions on making future IGCC installations until they have observed the installation and operation of these new plants.

Capital cost estimates for all power generation technologies are exhibiting considerable upward trends. Market pricing of technology components, coupled with commodity and labor demand worldwide, is rapidly escalating capital costs. These costs increases are not confined to any particular generation technology; they apply across the industry. The +/-25 percent accuracy range reflects the market volatility and the screening level nature of the estimate methodology.

Based on the assumptions, conditions, and engineering estimates made in this study, the USCPC option is the preferred technology selection for addition of a nominal 2,000 MW net output at the Glades site. The busbar cost of the USCPC case is nearly 10 percent less than SPC, which is the second lowest busbar cost case. USCPC will have good environmental performance because of its high efficiency. Emissions of NO_x and PM will be very similar across all technologies. Sulfur emissions would be slightly lower for IGCC than the PC and CFB options, although start-up and shutdown flaring will reduce the potential benefit of IGCC. The lower expected reliability of IGCC, particularly in the first years of operation, could compromise FPL's ability to meet the baseload generation requirement and require FPL to run existing units at higher capacity factors.

For the 2012-2014 planning time period, USCPC will be the best technical and economic choice for the installation of 2,000 MW of capacity at the Glades site.

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9.0 Contributors

This report was prepared collaboratively by Black & Veatch and FPL, as co-authors. Project team leads were David Hicks, Senior Director of Project Development, FPL, and Samuel Scupham, Technology Consultant, Black & Veatch Corporation. Messers Hicks and Scupham were supported in the preparation of this report by technical staff of their respective companies, to who they express their appreciation.

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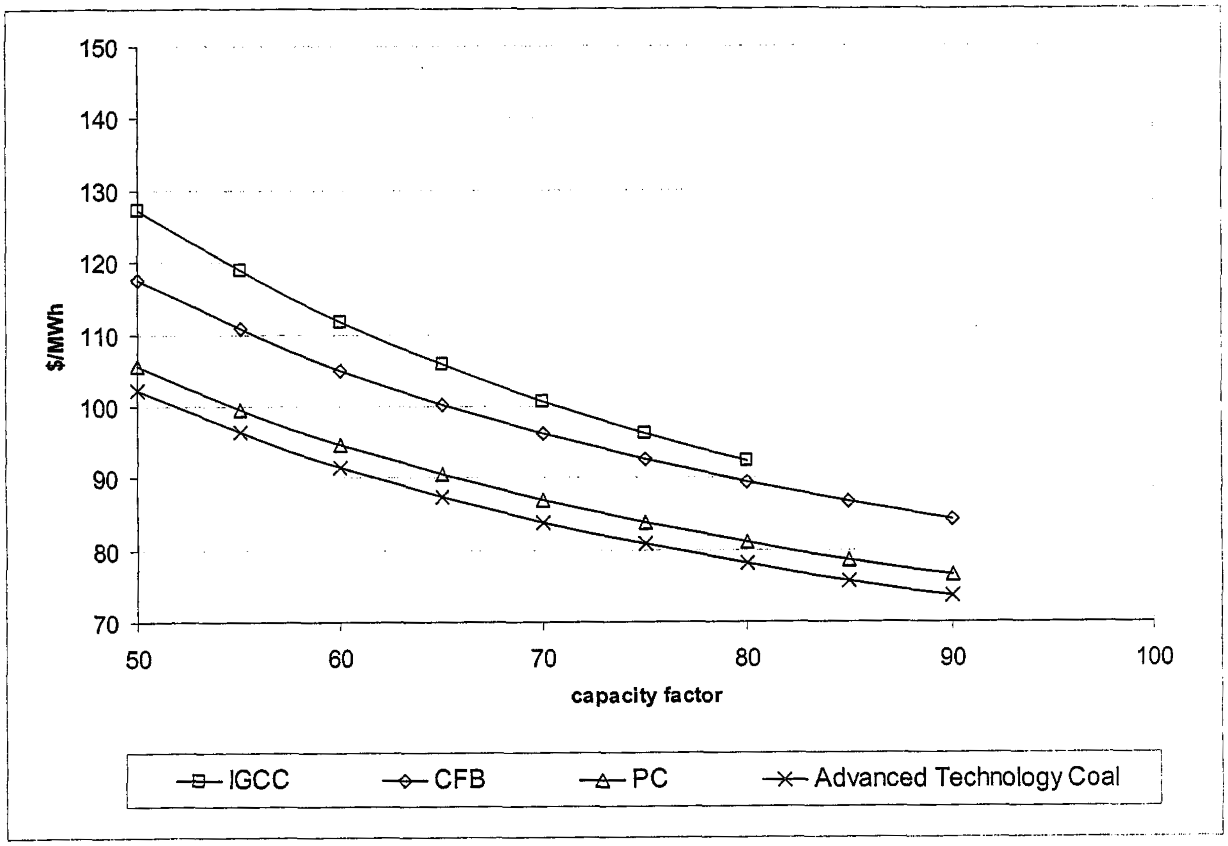
Appendix N

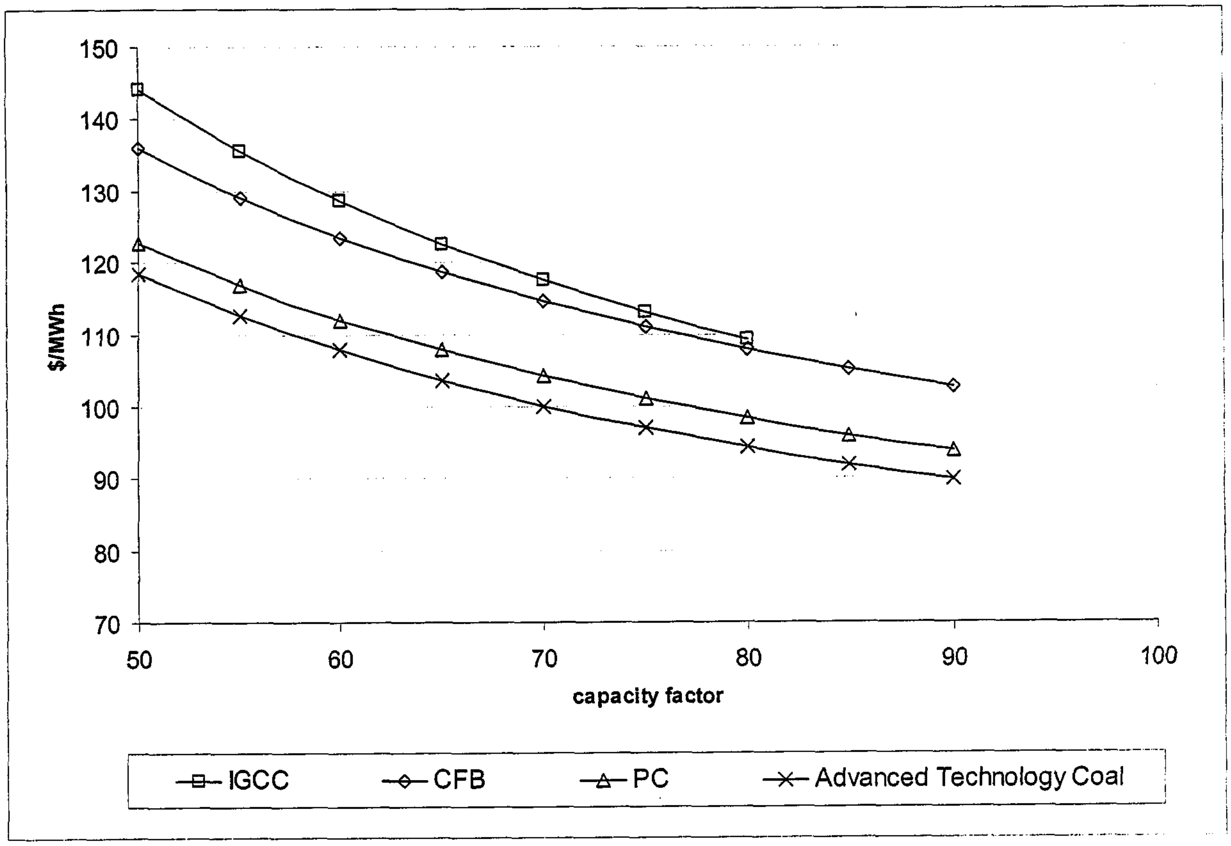
FPL – Only Confirming Economic Analyses of Four Coal-Based Technologies

(Without Allowance Costs)



FPL – Only Confirming Economic Analyses of Four Coal-Based Technologies

(With Allowance Costs)



Appendix O

Transmission Interconnection and Integration Information for the Non-Coal Units in the Two Resource Plans

In regard to the two resource plans utilized in FPL's economic and fuel diversity analyses, the Fuel Diversity Resource Plan with Coal (Plan with Coal) included the two advanced technology coal units plus one non-coal unit in the 2012 – 2016 time period. The Resource Plan without Coal (Plan without Coal) included no coal unit additions and three non-coal units in the same 2012 – 2016 time period. Transmission interconnection and integration information for the two advanced technology coal units in the Plan with Coal is presented in Section III.D of the Need Study document. Similar transmission interconnection and integration information for the non-coal units included in both resource plans is addressed in this appendix.

The Plan with Coal includes one non-coal unit added in 2015, the South Florida Combined Cycle (CC) unit. This unit is assumed to be sited in the vicinity of the West County Energy Center and connected to a new 230 kV section at the South Florida substation. The South Florida 500 kV and South Florida 230 kV sections would be connected via a 500/230 kV autotransformer. Additionally, the Corbett to Green 230 kV and the Corbett to Germantown 230 kV lines would be re-routed from the Corbett 230 kV substation to the South Florida 230 kV substation.

The facilities required for the interconnection and integration of South Florida CC unit include the connections of the South Florida CC unit's generator step up (GSU) transformers to the collector yard, including attendant bus equipment, the string buses from the collector yard to the South Florida 230 kV substation, the South Florida 230 kV substation, the associated transmission line connections, and the circuit breaker and overhead ground wire upgrades required. Construction of these transmission facilities will be done in the same manner as described in Section III.D.

The costs of the transmission facilities for the South Florida CC unit are provided below in Table O-1.

Table O – 1

Costs and Schedule for Transmission Facilities for Non-Coal Units in the Plan with Coal

	Facility Description		Total Cost	Construction Start	Construction Finish
TF-7	The connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard and the string buses from the collector yard to the South Florida 230 kV substation; (TF-7)		$ 6,900,000	August-2013	July-2014
	GSU Transformers	$ -			
	Substation Construction	$ 6,900,000			
	Total	$ 6,900,000			
TF-8	The South Florida 230 kV substation; (TF-8)		$ 43,700,000	May-2013	July-2014
	Substation Construction	$ 43,700,000			
	Total	$ 43,700,000			
TF-9	The re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation; (TF-9)		$ 4,000,000	August-2013	July-2014
	Transmission Line Construction	$ 4,000,000			
	Total	$ 4,000,000			
TF-10	The circuit breaker and overhead ground wire upgrades required; (TF-10)		$ 3,800,000	January-2014	April-2015
	Substation Construction	$ 2,700,000			
	Transmission Line Construction	$ 1,100,000			
	Total	$ 3,800,000			
	Total South Florida CC unit		**$ 58,400,000**		

Notes:
1. Costs were estimated in 2007 dollars and then escalated to the year that the expense would be incurred.
2. TF- Transmission Facilities for Fuel Diversity Resource Plan with Coal (Plan with Coal).

The Plan without Coal includes 3 non-coal CC units. The South Florida CC unit that is assumed to come in-service in 2015 in the Plan with Coal is accelerated to 2012 for the Plan without Coal. Those transmission facilities in the Plan with Coal discussed above that would have been needed in 2015 would instead be accelerated to 2012. In addition, the Plan without

Coal includes two CC units at the FGPP site that are assumed to come in-service in 2014 and 2016, respectively. The transmission facilities discussed in Section III.D for the two coal units at FGPP in the Plan with Coal would be postponed to 2014 and 2016 for the Plan without Coal.

The facilities required for the interconnection and integration of the two CC units at the FGPP site are very similar to those described in Section III.D with the exception that the connections of the CC units' GSU transformers to FGPP 500 kV switchyard would include the addition of collector yards, including attendant bus equipment, and the string buses from the collector yards to the FGPP 500 kV switchyard.

In 2014, when the first 1,119 MW CC unit is expected to go in-service, the FGPP switchyard will be connected by two new 500 kV transmission lines to the 500 kV facilities at the new Hendry transmission substation. This substation will be located in Hendry County approximately 25 miles south of the FGPP switchyard. The Hendry substation will have both 500 kV facilities and 230 kV facilities. FPL's existing Andytown to Orange River 500 kV line will be looped into the Hendry 500 kV section by constructing two new parallel 500 kV lines from Hendry substation to FPL's existing 500 kV right-of-way approximately 24 miles to the south. At the point where the new lines meet the existing Andytown to Orange River 500 kV line, the existing line will be cut and rerouted, modifying the Andytown to Orange River 500 kV line so that it becomes two new 500 kV lines: the Hendry to Orange River 500 kV line and the Hendry to Andytown 500 kV line. The 500 kV facilities will be stepped down and connected via a 500/230 kV auto-transformer to 230 kV facilities at the Hendry substation. The existing Alva to Corbett 230 kV line that is in close proximity to the proposed Hendry substation will be looped into the Hendry 230 kV section. This will result in the Alva to Corbett 230 kV line becoming two lines: the Hendry to Alva 230 kV line and the Hendry to Corbett 230 kV line.

In 2016, when the second 1,119 MW CC unit is expected to go in-service, the unit will also be connected to the FGPP 500 kV switchyard. In order to integrate this additional generation, a new 500 kV transmission line from the Hendry substation to the Andytown substation will be necessary. At this point, this new 500 kV line will be connected to an existing Andytown to Levee line, creating the Hendry to Levee 500 kV line.

The costs for the transmission facilities associated with all of these non-coal generating units in the Plan without Coal are presented in Table O – 2.

Table O – 2

Costs and Schedule for Transmission Facilities for All Units in the Plan without Coal

Facility	Description	Total Cost	Construction Start Date	Construction Finish Date
TFND-1	The connection of FGPP 1 and 2 CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard and the string buses from the collector yard to the FGPP switchyard, and attendant bus equipment; (TFND-1)	$ 20,100,000	May-2012	July-2013
TFND-2	The FGPP switchyard; (TFND-2)	$ 24,000,000	May-2012	July-2013
TFND-3	The Hendry 500/230 kV Substation; (TFND-3)	$ 61,600,000	September-2011	July-2013
TFND-4	The two 500 kV transmission lines from the FGPP switchyard to the Hendry Substation; (TFND-4)	$ 130,700,000	August-2011 August-2011	July-2013 May-2014
TFND-5	The looping in of the Alva to Corbett 230 kV and the Andytown to Orange River 500 kV transmission lines into the Hendry substation; (TFND-5)	$ 183,600,000	August-2013 August-2011	July-2013 May-2014
TFND-6	A new 500 kV transmission circuit from the Hendry to Levee substations. This transmission line will be constructed between Hendry and Andytown substations and connected to an existing Andytown to Levee 500 kV line resulting in a Hendry to Levee 500 kV transmission line; (TFND-6)	$ 100,100,000	August-2011	November-2015
	Total FGPP CC units =	$ 520,100,000		
TFND-7	The connection of South Florida CC unit GSU transformers to the collector yard, including attendant bus equipment, the collector yard and the string buses from the collector yard to the South Florida 230 kV substation; (TFND-7)	$ 6,100,000	August-2010	July-2011
TFND-8	The South Florida 230 kV substation; (TFND-8)	$ 39,000,000	May-2010	July-2011
TFND-9	The re-route of the Corbett-Green and the Corbett-Germantown 230 kV lines from Corbett substation to South Florida substation; (TFND-9)	$ 3,600,000	August-2010	July-2011
TFND-10	The circuit breaker and overhead ground wire upgrades required; (TFND-10)	$ 3,400,000	January-2011	April-2012
	Total South Florida CC unit =	$ 52,100,000		

Notes:
1. Costs were estimated in 2007 dollars and then escalated to the year that the expense would be incurred.
2. TFND- Transmission Facilities for the Resource Plan without Coal