EXHIBIT NUMBER: 3

TITLE: COMPOSITE CONFIDENTIAL STIP - 3

DOCKET NO: 041393-EI

COMPANY: Progress Energy Florida, Inc.

WITNESS: Samuel S. Waters

DESCRIPTION: COMPOSITE EXHIBIT - CONFIDENTIAL:

1) Confidential portions of Progress' responses to Staff's First Set of Interrogatories (Nos. 3, 6, and 9);
2) Progress' response to Staff's First Request for Production of Documents (No. 1);
3) Confidential portion of Progress' response to Staff's Third Set of Interrogatories (No. 22);

PROFFERED BY: STAFF

NL 12-1-06 (entire DN)

CONFIDENTIAL

DECLASSIFIED

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 041393-EI EXHIBIT NO. Composite #3
COMPANY/
WITNESS: Staff - FPSC
DATE: 6-2-05

DOCUMENT NUMBER-DATE
05382 JUN-3 05
FPSC-COMMISSION CLERK

Southern Company Generation and Energy Marketing
270 Peachtree Street NW
Atlanta, Georgia 30303

CONFIDENTIAL CONFIDENTIAL

SOUTHERN COMPANY
Energy to Serve Your World™

November 24, 2004

041393-EI

Mr. Robert F. Caldwell
Florida Power Corporation
d/b/a Progress Energy Florida, Inc.
410 South Wilmington Street
Raleigh, North Carolina 27601

Re: Contracts for the Purchase of Capacity and Energy and Plant Miller

Dear Mr. Caldwell:

On behalf of one or more of Georgia Power Company ("Georgia Power"), Gulf Power Company ("Gulf Power") and Southern Power Company ("Southern Power"), Southern Company Services, Inc. together with Florida Power Corporation, doing business as Progress Energy Florida, Inc ("FPC") have entered into two (2) Contracts for the Purchase of Capacity and Energy described below (collectively the "PPAs"), each dated as of November 24, 2004. As used in this letter agreement, "SCS" means Southern Company Services, Inc. as agent for one or more of Alabama Power Company ("Alabama Power"), Georgia Power, Gulf Power and Southern Power.

1. Each of the PPAs involve the sale of capacity and energy to FPC beginning June 1, 2010 from a specified generation resource. Specifically, one PPA involves a portion of Plant Scherer Unit 3 owned by Georgia Power and Gulf Power ("Scherer PPA") and one PPA involves Southern Power's Franklin Unit 1 ("Franklin PPA"). Through this letter agreement, the parties desire to set forth their understanding regarding possible transactions involving capacity and energy from portions of Alabama Power's Plant Miller in the event that such portions become available (under the circumstances described below) to SCS for making wholesale power transactions.

2. Alabama Power is the owner of Plant Miller Units 1 through 4 located in Jefferson County, Alabama. Currently, a portion of the capacity and associated energy from those units is being sold at wholesale to Florida Power Corporation, Florida Power & Light Company and Jacksonville Electric Authority (such portion is referred to as the "Miller Capacity"). Beginning on June 1, 2010, it is Alabama Power's current intention to no longer make long term (i.e., greater than one (1) year) wholesale sales from the Miller Capacity and to recover the costs associated with such capacity through retail

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rates. It is uncertain whether Alabama Power will make a filing with the Alabama Public Service Commission ("APSC") in order to recover such costs through retail rates.

3. However, in the event that Alabama Power finally determines in its sole discretion that it will sell a portion of the Miller Capacity at wholesale on a long term basis during any time from June 1, 2010 to December 31, 2015, then SCS shall within 60 days provide notice to FPC that Alabama Power has made such determination ("Miller Notice"). The portion of the Miller Capacity that Alabama Power determines to sell in this manner shall be referred to herein as the "Available Miller Capacity." The Miller Notice shall also specify the time period for which Alabama Power intends to sell such Available Miller Capacity at wholesale ("Sale Term"). Upon FPC's receipt of the Miller Notice, FPC shall have 30 days to notify SCS ("Miller Discussion Notice") that it desires to enter into discussions regarding the purchase of the lesser of: (i) twenty six percent (26%) of the capacity and energy associated with the Available Miller Capacity, rounded down to the nearest whole megawatt; or (ii) the amount of capacity purchased by FPC under the Franklin PPA (as such PPA may exist from time to time) (such lesser amount is hereinafter referred to as the "Subject Miller Capacity").

4. If FPC does not provide the Miller Discussion Notice in a timely manner, SCS shall be free to market and sell the Subject Miller Capacity to any third party(ies) without restriction and without further obligation to FPC.

5. If FPC provides the Miller Discussion Notice in a timely manner, SCS shall engage in discussions exclusively with FPC for a period of 90 days after SCS receives the Miller Discussion Notice ("Miller Discussion Period") regarding a potential sale of all of the capacity and energy from all of the Subject Miller Capacity for a term equal to the Sale Term, but in no event beyond December 31, 2015 unless the parties mutually agree otherwise. In connection therewith, SCS shall provide FPC with SCS's proposal regarding the following terms for such sale: (i) capacity and energy prices; (ii) the charge for variable operation and maintenance costs; (iii) heat rate; and (iv) availability guarantees (such terms in (i) through (iv) are referred to as the "Specified Terms"); provided, however, neither party shall be required to enter into any agreement for the purchase or sale of the Subject Miller Capacity.

6. If the parties are unable to reach a mutually acceptable agreement during the Miller Discussion Period regarding such purchase and sale, SCS shall be free to market and sell the Subject Miller Capacity to other parties. Notwithstanding the foregoing sentence, however, for a period of one (1) year after the end of the Miller Discussion Period, before SCS sells some portion of the capacity and energy from the Subject Miller Capacity ("Marketed Portion") to any other party at Specified Terms materially more favorable in the aggregate than the Specified Terms previously offered to FPC (without regard to any other terms and conditions of a potential transaction) (such more favorable Specified Terms are referred to herein as the "Miller Specified Terms"), SCS shall first provide FPC the right to negotiate to purchase all of the capacity and energy from the Marketed Portion under the Miller Specified Terms for a term equal to the Sale Term (but in no event beyond December 31, 2015 unless the parties mutually

agree otherwise). However, in order to exercise such right to negotiate, FPC must provide SCS notice within 10 business days after receiving the Miller Specified Terms. If FPC timely provides such notice, SCS shall engage in such negotiations with FPC for a period not to exceed 30 days after SCS receives such notice; provided, however, neither party shall be required to enter into any agreement for the purchase or sale of the Subject Miller Capacity.

7. In the event that the parties enter into an agreement for the purchase and sale of capacity and energy from the Subject Miller Capacity as contemplated in this letter agreement ("Miller Agreement"), the parties shall negotiate to reduce the amount of capacity and energy purchased by FPC under the Franklin PPA during the term of the Miller Agreement by reducing such capacity and energy on a megawatt for megawatt basis from the Franklin PPA. If such reduction results in the amount of capacity being purchased pursuant to the Franklin PPA being less than 50 MW for any period of time, either party may reduce the amount of capacity and energy purchased under such PPA during such time to 0 MW by providing notice to the other party within 30 days after the execution of the Miller Agreement. In addition, if the amount of capacity purchased under the Franklin PPA is reduced, the parties shall negotiate to reach agreement on appropriate modifications to the terms of such PPA (including those pertaining to heat rate and scheduling requirements (as applicable) and appropriate pro rata reductions in the megawatt amounts in Section 7.4 of such PPA) that reflect the reduction in capacity purchased under that PPA. If the parties are unable to reach agreement on such modifications within 90 days after the Miller Agreement is executed, the Miller Agreement shall terminate and (subject to any reductions in capacity made pursuant to numbered paragraph 4 of the letter agreement dated November 24, 2004 between Southern Company Services, Inc. and FPC regarding capacity from Plant Scherer) the parties shall be obligated to sell and purchase the full amount of capacity and energy (prior to any reductions under this paragraph) under the PPAs as they were originally executed by the parties.

8. In the event that the parties do not reach a mutually acceptable agreement for the purchase and sale of capacity and energy from the Subject Miller Capacity as contemplated in this letter agreement, the PPAs will be unaffected.

9. This letter agreement shall immediately terminate upon the earlier to occur of: (i) the issuance of an order by the APSC allowing Alabama Power to recover the costs associated with the Miller Capacity in retail rates; or (ii) the date that such costs are reflected in Alabama Power's retail cost of service for ratemaking purposes. Upon such termination, neither SCS nor any of its affiliates shall have any obligation to FPC hereunder with respect to the Miller Capacity or any portion thereof.

10. To the extent this letter agreement is not terminated as provided in paragraph 9 above, this letter agreement shall terminate upon the earlier to occur of: (i) the expiration and/or termination of the Franklin PPA; (ii) the assignment by FPC of any of its rights or obligations under either of the PPAs to any other party; (iii) an Event of Default (as defined in the PPAs) under either PPA by FPC; or (iv) December 31, 2015.

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Upon such termination, no party shall have any further liability or obligation to the other under this letter agreement.

11. Any notice required under this letter agreement shall be in writing and shall be deemed provided when received. Facsimile (and the receipt thereof by the receiving party) shall be an acceptable form of notice; provided, however, that a paper copy of such notice must also be mailed to the receiving party on the day of such facsimile.

12. This letter agreement and the terms hereof shall be deemed to be Confidential Information under and as defined by the PPAs.

If the foregoing accurately reflects FPC's understanding, please sign your name on behalf of FPC in the space provided below.

Sincerely,

SOUTHERN COMPANY SERVICES, INC.

William N. McKenzie
Vice President, Business Development
As agent for
Alabama Power Company
Georgia Power Company
Gulf Power Company
Southern Power Company

AGREED AND ACCEPTED

FLORIDA POWER CORPORATION D/B/A
PROGRESS ENERGY FLORIDA, INC.

PROGRESS ENERGY SERVICE COMPANY
LEGAL DEPT.
APPROVED
Date 10/22/04
By mm

By: ______________________
Name: Robert F. Caldwell
Title: Vice President, Regulated Commercial Operations

Southern Company Generation and Energy Marketing
270 Peachtree Street NW
Atlanta, Georgia 30303

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SOUTHERN COMPANY
Energy to Serve Your World℠

November 24, 2004

Mr. Robert F. Caldwell
Florida Power Corporation
d/b/a Progress Energy Florida, Inc.
410 South Wilmington Street
Raleigh, North Carolina 27601

Re: Contracts for the Purchase of Capacity and Energy and Plant Scherer

Dear Mr. Caldwell:

On behalf of one or more of Georgia Power Company ("Georgia Power"), Gulf Power Company ("Gulf Power") and Southern Power Company ("Southern Power"), Southern Company Services, Inc. together with Florida Power Corporation, doing business as Progress Energy Florida, Inc. ("FPC") have entered into two (2) Contracts for the Purchase of Capacity and Energy described below (collectively the "PPAs"), each dated as of November 24, 2004. As used in this letter agreement, "SCS" means Southern Company Services, Inc. as agent for one or more of Georgia Power, Gulf Power and Southern Power.

1. Each of the PPAs involves the sale of capacity and energy to FPC beginning June 1, 2010 from a specified generation resource. Specifically, one PPA involves a portion of Plant Scherer Unit 3 owned by Georgia Power and Gulf Power ("Scherer PPA") and one PPA involves Southern Power's Franklin Unit 1 ("Franklin PPA"). Through this letter agreement, the parties desire to set forth their understanding regarding possible transactions involving capacity and energy from another portion of Plant Scherer Unit 3 in the event that such portion becomes available (under the circumstances described below) to SCS for making wholesale power transactions.

2. Georgia Power and Gulf Power are the owners of an additional portion of Plant Scherer Unit 3 that has a capacity of 75 MW and which is not involved in the Scherer PPA ("Additional Scherer Capacity"). Southern Company Services, Inc. (on behalf of Georgia Power and Gulf Power) has executed a wholesale transaction with another party ("Third Party") whereby the Third Party has agreed to purchase the Additional Scherer Capacity along with other capacity, subject to certain conditions precedent.

3. In the event that SCS finally determines in its sole discretion that the Third Party will not be obligated to purchase all or a substantial portion of the Additional Scherer Capacity, SCS shall within 60 days after such determination provide FPC notice of such determination. Upon FPC's receipt of such notice, FPC shall have 30 days to notify SCS ("Scherer Notice") that it desires to purchase thirty percent (30%) of the capacity and energy associated with the Additional Scherer Capacity that is not sold to the Third Party (such amount of the Additional Scherer Capacity is hereinafter referred to as the "Subject Scherer Capacity.")

4. If FPC provides the Scherer Notice in a timely manner, the parties shall within 30 days after such notice execute a binding agreement in substantially the form of the Scherer PPA whereby SCS shall sell and FPC shall purchase all of the capacity and energy from the Subject Scherer Capacity (provided that any provisions conditioning the parties' obligations or the agreement on FPC's ability to obtain transmission service and/or regulatory approval shall not allow any party to terminate or otherwise modify any of the PPAs). In the event that FPC does not provide the Scherer Notice in a timely manner, SCS shall be entitled to sell such capacity and energy to any other party without restriction and shall have no further obligation to FPC regarding any portion of the Additional Scherer Capacity. In the event that the parties enter into an agreement for the purchase and sale of all of the capacity and energy associated with the Subject Scherer Capacity as contemplated in this letter agreement ("Second Scherer Agreement"), the parties shall negotiate to reduce the capacity and energy purchased by FPC on a megawatt for megawatt basis from the Franklin PPA. If such reduction results in the amount of capacity being purchased pursuant to the Franklin PPA being less than 50 MW for any period of time, either party may reduce the amount of capacity and energy purchased under such PPA during such time to 0 MW by providing notice to the other party within 30 days after the execution of the Second Scherer Agreement. In addition, if the amount of capacity purchased under the Franklin PPA is reduced, the parties shall negotiate to reach agreement on appropriate modifications to the terms of such PPA (including those pertaining to heat rate and scheduling requirements (as applicable) and appropriate pro rata reductions in the megawatt amounts in Section 7.4 of such PPA) that reflect the reduction in capacity purchased under that PPA. If the parties are unable to reach agreement on such modifications within 90 days after the Second Scherer Agreement is executed, the Second Scherer Agreement shall terminate and (subject to any reductions in capacity made pursuant to numbered paragraph 7 of the letter agreement dated November 24, 2004 between Southern Company Services, Inc. and FPC regarding capacity from Plant Miller) the parties shall be obligated to sell and purchase the full amount of capacity and energy (prior to any reductions under this paragraph) under the PPAs as they were originally executed by the parties.

5. In the event that SCS finally determines in its sole discretion that the Third Party will be obligated to purchase all or a substantial portion of the Additional Scherer Capacity, SCS shall provide FPC with written notice of the same and, upon such notice, this letter agreement shall immediately terminate. Upon such termination, neither SCS nor any of its affiliates shall have any obligation to FPC hereunder with respect to the Additional Scherer Capacity or any portion thereof.

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6. To the extent this letter agreement is not terminated as provided in paragraph 5 above, this letter agreement shall terminate upon the earlier to occur of: (i) the expiration and/or termination of the Franklin PPA; (ii) the assignment by FPC of any of its rights or obligations under either of the PPAs to any other party; (iii) an Event of Default (as defined in the PPAs) under either PPA by FPC; or (iv) December 31, 2015. Upon such termination, no party shall have any further liability or obligation to the other under this letter agreement.

7. Any notice required under this letter agreement shall be in writing and shall be deemed provided when received. Facsimile (and the receipt thereof by the receiving party) shall be an acceptable form of notice; provided, however, that a paper copy of such notice must also be mailed to the receiving party on the day of such facsimile.

8. This letter agreement and the terms hereof shall be deemed to be Confidential Information under and as defined by the PPAs.

If the foregoing accurately reflects FPC's understanding, please sign your name on behalf of FPC in the space provided below.

Sincerely,

SOUTHERN COMPANY SERVICES, INC.

William N. McKenzie
Vice President, Business Development
As agent for
Georgia Power Company
Gulf Power Company
Southern Power Company

AGREED AND ACCEPTED

FLORIDA POWER CORPORATION D/B/A
PROGRESS ENERGY FLORIDA, INC.

PROGRESS ENERGY SERVICE COMPANY
LEGAL DEPT.
APPROVED

By: ____________________
Name: Robert F. Caldwell
Title: Vice President, Regulated Commercial Operations

PROGRESS ENERGY FLORIDA'S ANSWERS TO WHITE SPRINGS' FIRST SET OF INTERROGATORIES (NO. 3)
DOCKET NO. 041393-EI

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3. **Please describe any dispatch rights Progress will have for Scherer Unit 3 and Franklin Unit 1 under the Unit Power Sales Agreements.**

RESPONSE: Regarding Scherer Unit 3, the new agreement calls for Progress Energy to provide notification of its scheduled hourly power from the unit by 1000 CPT of the business day prior to the desired delivery date. The minimum amount of scheduled energy for any hour is 50% of the contract capacity (currently projected to be 74 MW), with a minimum delivery schedule of 24 hours and a minimum time of 24 hours between a scheduled shutdown and a scheduled start.

The Franklin Unit 1 agreement calls for Progress Energy to provide notification of its scheduled hourly power from the unit by 0900 CPT of the business day prior to the desired delivery date. The minimum amount of energy scheduled from the unit in any hour is 50 MW, with additional amounts scheduled in 50 MW increments up to the total amount of the contract capacity (currently projected to be 350 MW). The minimum duration of the scheduled energy is 16 consecutive hours, and the minimum time between a scheduled shutdown and a scheduled startup is 8 hours.

Both agreements allow Progress Energy to change the schedule, to a maximum of twice a day, in any hour of a delivery day with 4 hours notice.

Provision is also made to allow Progress Energy to change the Franklin schedule with less than four hours notice in the event that its generation reserves fall below the largest generating unit available on its system.

These scheduling provisions are similar to those provided in the existing 1988 UPS agreement. However, the existing agreement called for Progress Energy (then Florida Power Corporation) to schedule energy from the designated units in excess of a fifty percent output factor on an annual basis through the year 2000. The new agreements have no such provision, allowing Progress Energy to schedule in a more flexible and economic manner.

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6. **Page 3 of the petition describes how energy charges for the Southern Company agreements will be based on a guaranteed heat rate at the Franklin unit but an actual heat rate at the Scherer unit. Please explain why different heat rates are used.**

RESPONSE: Due to the differences in fuel types, there is a difference in the way energy charges are calculated for the two units. For Scherer Unit 3, which burns coal, the heat rate may vary due to the fuel used in the unit. The fuel use is managed by the Southern system to obtain the best combination of heat rate and fuel price. Under the terms of the new agreement, the heat rate for Scherer Unit 3 will be derived from the "Informational Schedule No. 2 (Energy Costs by Sources)", or other applicable informational schedule or filing under the Southern Company Intercompany Interchange Contract (IIC) among the electric operating companies of the Southern system. In other words, the heat rate will be applied consistently with the way it is applied within the Southern operating companies.

Regarding the Franklin combined cycle unit, there is not an effect on heat rate due to the burning of natural gas. There is, however, an effect due to varying the output of the combined cycle unit. Therefore, the Franklin Unit 1 agreement calls for a guaranteed heat rate at different scheduled levels of output, rather than using an actual heat rate which may be measured at an actual operating condition other than the schedule delivered to Progress Energy. It should be remembered that while Progress may take its 350 MW pro rata share of the Franklin unit, the unit may be operating at a different output level up to its total capacity, thus varying the heat rate from what it would be at the 350 MW level.

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	Evaluation Base Case 05/26/04	Scenario: Base Case SoCo UPS through Dec 2015
2004	188 MW Winter Purchase	188 MW Winter Purchase (Dec '04 - Feb '05)
2005	Hines 3	Hines 3
2006	3 Augm. CTs	3 Augm. CTs
2007	Hines 4	Hines 4
2008		
2009	* Augm. CT (May 2009) CC	* Augm. CT (May 2009) CC
2010	* CC (May 2010)	SoCo UPS (Jun '10-Dec '15)
2011		* CC (May 2011)
2012	* CC (May 2012)	
2013	CC	CC
2014		
2015	* Puv Coal (May 2015)	* Puv Coal (May 2015) Puv Coal
2016		
2017	* Puv Coal (May 2017)	Augm. CT (May 2017)
2018		* CC (May 2018)
2019	* Augm. CT (May 2019)	
2020	* Puv Coal (May 2020)	* Puv Coal (May 2020)
2021		
2022	* Puv Coal (May 2022)	* Puv Coal (May 2022)
2023		

Note: Units commissioned in December unless otherwise defined

Resource Additions		
	Hines 3-4	Hines 3-4
	4 CCs	4 CCs
	5 CTs	5 CTs
	4 Puv Coal	4 Puv Coal
Total MW Added	5,084	5,084
delta		

Ratings	**Winter**
Hines 3	582
Hines 4	517
CC	536
CT Non-Aug	188
CT Aug	188
Puv Coal	500
SoCo UPS Purchase	425

Spreadsheet 1a.xls

DOCUMENT NUMBER-DATE

01180 FEB-1 05

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This docketed notice of intent was filed with Confidential Document No. 01180-05 The document has been placed in confidential storage pending timely receipt of a request for confidentiality.

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Purchase Name	**Southern Company (thru 12/2015)**
Production costs from	Strategist
Construction escalation rate	2.50%
Fixed O&M escalation rate	2.50%
Discount rate	8.16%

2004 dollars

	$/kW TPC	$/kW TCR	CPV FCR	$/kW CPVRR	$/kW-yr ECC	$/kW-yr FOM	Avg MW Capacity	Life	Levelized FOM
CT	328	349	1.420	495	35.04	2.36	173	25	3.48
CC	440	480	1.486	713	50.46	2.79	507	25	4.12
Coal	1,042	1,170	1.528	1,787	105.81	29.18	500	40	43.12

Months of Deferral/Advance

Deferrals	From	To	Number of Units		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CC	May-10	May-11	1	0	0	0	0	0	0	0	8	4	0	0	0	0	0	0	0	0	0	0	0
CC	May-12	May-18	1	0	0	0	0	0	0	0	0	0	8	12	12	12	12	12	4	0	0	0	0
			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total CT Deferral					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total CC Deferral					0	0	0	0	0	0	8	4	8	12	12	12	12	12	4	0	0	0	0
Total Coal Deferral					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Advances	To	From	Number of Units		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CT	May-17	May-19	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	12	4	0	0	0
Coal	Dec-15	May-17	1	0	0	0	0	0	0	0	0	0	0	0	0	1	12	4	0	0	0	0	0
			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
			1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total CT Advance					0	0	0	0	0	0	0	0	0	0	0	0	0	8	12	4	0	0	0
Total CC Advance					0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Coal Advance					0	0	0	0	0	0	0	0	0	0	0	1	12	4	0	0	0	0	0

Deferral Credits ($/kW-yr)	Incl. in Credit?	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CT ECC		35.04	35.92	36.82	37.74	38.68	39.65	40.64	41.66	42.70	43.76	44.86	45.98	47.13	48.31	49.52	50.75	52.02	53.32	54.66
CC ECC		50.46	51.72	53.02	54.34	55.70	57.09	58.52	59.98	61.48	63.02	64.60	66.21	67.87	69.56	71.30	73.08	74.91	76.78	78.70
Coal ECC		105.81	108.46	111.17	113.95	116.80	119.72	122.71	125.78	128.92	132.15	135.45	138.84	142.31	145.86	149.51	153.25	157.08	161.01	165.03
CT FOM	0	2.36	2.42	2.48	2.54	2.60	2.67	2.73	2.80	2.87	2.94	3.02	3.09	3.17	3.25	3.33	3.41	3.50	3.59	3.68
CC FOM	0	2.79	2.86	2.93	3.01	3.08	3.16	3.24	3.32	3.40	3.49	3.57	3.66	3.75	3.85	3.94	4.04	4.14	4.25	4.35
Coal FOM	0	29.18	29.91	30.65	31.42	32.21	33.01	33.84	34.68	35.55	36.44	37.35	38.28	39.24	40.22	41.23	42.26	43.31	44.40	45.51

All Costs in $Thousands

Deferral/(Advance) Credit (ECC Only)	NPV of Infinity Def/(Adv)	NPV	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CT Deferrals		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CC Deferrals	0	104441	0	0	0	0	0	0	19791	10143	20793	31968	32768	33587	34427	35287	12056	0	0	0	0
Coal Deferrals		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CT Advances		-5762	0	0	0	0	0	0	0	0	0	0	0	0	0	-5563	-8553	-2922	0	0	0
CC Advances		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Coal Advances	0	-38984	0	0	0	0	0	0	0	0	0	0	0	-5785	-71153	-24311	0	0	0	0	0
Total Deferral/Advance Credit/(Cost)		59695	0	0	0	0	0	0	19791	10143	20793	31968	32768	27802	-36726	5414	3504	-2922	0	0	0

Purchase Costs (Southern Company (thru 12/2015)) *(Note: Shaded area for information only)*

	NPV	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Months in Year		0	0	0	0	0	0	7	12	12	12	12	12	0	0	0	0	0	0	0
Capacity	106879	0	0	0	0	0	0	21887	37521	37521	37521	37521	37521	0	0	0	0	0	0	0
Capacity Discount	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pipeline	13744	0	0	0	0	0	0	2707	4690	4776	4866	4955	5041	0	0	0	0	0	0	0
Transmission	28183	0	0	0	0	0	0	5772	9894	9894	9894	9894	9894	0	0	0	0	0	0	0
Total Fixed Costs	148806	0	0	0	0	0	0	30365	52105	52191	52281	52370	52456	0	0	0	0	0	0	0
Change in System Production costs (from model)	33773	0	0	0	0	0	0	5589	15497	18806	18485	17689	17716	-45161	7794	4253	0	0	0	0
Costs Not Included in Strategist (unshaded area above)	41927	0	0	0	0	0	0	8478	14584	14670	14760	14849	14935	0	0	0	0	0	0	0
Total Scenario Cost	75700	0	0	0	0	0	0	14067	30081	33476	33245	32538	32652	-45161	7794	4253	0	0	0	0
Additional Cost of Purchases (Scenario Cost less Deferral Credit)	16006	0	0	0	0	0	0	-5724	19938	12683	1277	-230	4850	-8435	2381	750	2922	0	0	0
Cost of deferring plant infrastructure	-8317	0	0	0	0	0	0	-1923	-986	-2021	-3107	-3184	-2992	0	-2286	-1172	0	0	0	0
Additional Equity Cost	9304	0	0	0	0	0	0	4218	4021	3363	2638	1841	964	0	0	0	0	0	0	0
Net Cost of Southern Company (thru 12/2015)	16993	0	0	0	0	0	0	-3429	22974	14025	808	-1573	2822	-8435	95	-422	2922	0	0	0

Plant Infrastructure

Assumed cost of infrastructure 25637 $Thousands

	From	To		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
CC Deferral	5/1/2010	5/1/2011		0	0	0	0	0	0	8	4	0	0	0	0	0	0	0	0	0	0	0
CC Deferral	5/1/2012	5/1/2018		0	0	0	0	0	0	0	0	8	12	12	12	12	12	4	0	0	0	0
	To	From																				
Coal Advance	12/1/2015	5/1/2017		0	0	0	0	0	0	0	0	0	0	0	-1	-12	-4	0	0	0	0	0
Net				0	0	0	0	0	0	8	4	8	12	12	11	0	8	4	0	0	0	0
Deferral Credit				2488	2550	2614	2679	2746	2815	2885	2957	3031	3107	3184	3264	3346	3429	3515	3603	3693	3785	3880
Value of Deferral			8317	0	0	0	0	0	0	1923	986	2021	3107	3184	2992	0	2286	1172	0	0	0	0

Purchase Name
Production costs from
Construction escalation rate
Fixed O&M escalation rate
Discount rate

CT
CC
Coal

Deferrals	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CC	0	0	0	0	0	0	0	0	0	0	0
CC	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
Total CT Deferral	0	0	0	0	0	0	0	0	0	0	0
Total CC Deferral	0	0	0	0	0	0	0	0	0	0	0
Total Coal Deferral	0	0	0	0	0	0	0	0	0	0	0

Advances	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
CT	0	0	0	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
	0	0	0	0	0	0	0	0	0	0	0
Total CT Advance	0	0	0	0	0	0	0	0	0	0	0
Total CC Advance	0	0	0	0	0	0	0	0	0	0	0
Total Coal Advance	0	0	0	0	0	0	0	0	0	0	0

Deferral Credits ($/kW-yr)											
CT ECC	56.02	57.42	58.86	60.33	61.84	63.38	64.97	66.59	68.26	69.96	71.71
CC ECC	80.67	82.69	84.75	86.87	89.05	91.27	93.55	95.89	98.29	100.75	103.27
Coal ECC	169.16	173.39	177.72	182.16	186.72	191.39	196.17	201.07	206.10	211.25	216.54
CT FOM	3.77	3.86	3.96	4.06	4.16	4.26	4.37	4.48	4.59	4.71	4.82
CC FOM	4.46	4.57	4.69	4.80	4.92	5.05	5.17	5.30	5.44	5.57	5.71
Coal FOM	46.64	47.81	49.00	50.23	51.48	52.77	54.09	55.44	56.83	58.25	59.71

All Costs in $Thousands

Deferral/(Advance) Credit (ECI	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	
CT Deferrals	0	0	0	0	0	0	0	0	0	0	0	
CC Deferrals	0	0	0	0	0	0	0	0	0	0	0	
Coal Deferrals	0	0	0	0	0	0	0	0	0	0	0	
CT Advances	0	0	0	0	0	0	0	0	0	0	0	
CC Advances	0	0	0	0	0	0	0	0	0	0	0	
Coal Advances	0	0	0	0	0	0	0	0	0	0	0	
Total Deferral/Advance Credit	0	0	0	0	0	0	0	0	0	0	0	
Purchase Costs (Southern Co												
[illegible]	0	0	0	0	0	0	0	0	0	0	0	
Capacity	0	0	0	0	0	0	0	0	0	0	0	
Capacity Discount	0	0	0	0	0	0	0	0	0	0	0	
Pipeline	0	0	0	0	0	0	0	0	0	0	0	
Transmission	0	0	0	0	0	0	0	0	0	0	0	
Total Fixed Costs	0	0	0	0	0	0	0	0	0	0	0	
Change in System Production co	0	0	0	0	0	0	0	0	0	0	0	0
Costs Not Included in Strategist	0	0	0	0	0	0	0	0	0	0	0	
Total Scenario Cost	0	0	0	0	0	0	0	0	0	0	0	0
Additional Cost of Purchases (S	0	0	0	0	0	0	0	0	0	0	0	0
Cost of deferring plant infrastruc	0	0	0	0	0	0	0	0	0	0	0	
Additional Equity Cost	0	0	0	0	0	0	0	0	0	0	0	
Net Cost of Southern Compan	0	0	0	0	0	0	0	0	0	0	0	0

Plant Infrastructure
Assumed cost of infrastructure

CC Deferral	0	0	0	0	0	0	0	0	0	0	0
CC Deferral	0	0	0	0	0	0	0	0	0	0	0
Coal Advance	0	0	0	0	0	0	0	0	0	0	0
Net	0	0	0	0	0	0	0	0	0	0	0
Deferral Credit	3977	4076	4178	4283	4390	4500	4612	4727	4845	4967	5091
Value of Deferral	0	0	0	0	0	0	0	0	0	0	0

Southern Company (thru 12/2015) Purchase

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Scherer Cost	11,491	11,491	11,491	11,491	11,491	11,491									
Capacity (MW)	74	74	74	74	74	74									
Price ($/kW-mo)	12.94	12.94	12.94	12.94	12.94	12.94									
Franklin Cost	30,670	30,720	30,806	30,896	30,985	31,072									
Capacity (MW)	351	351	351	351	351	351									
Price ($/kW-mo)	6.18	6.18	6.18	6.18	6.18	6.18									
Pipeline Reservation ($/mmBtu-mo	6.47	6.54	6.66	6.79	6.91	7.03									
Pipeline Reservation (mmBtu-day)	59760	59760	59760	59760	59760	59760									
Transmission	9,894	9,894	9,894	9,894	9,894	9,894									
Price ($/kW-mo)	1.94	1.94	1.94	1.94	1.94	1.94									
Total Capacity	37,521	37,521	37,521	37,521	37,521	37,521									
Total Pipeline	4,640	4,690	4,776	4,866	4,955	5,041									
Annualized Fixed Costs	52,056	52,105	52,191	52,281	52,370	52,456									
Months	7	12	12	12	12	12									
Include Pipeline Reservation?	No														
Total Fixed Costs for Equity ($000)	27,659	47,415	47,415	47,415	47,415	47,415									
Price reduction															
Scherer price discount	0.00	0.00	0.00	0.00	0.00	0.00									
Franklin price discount	0.00	0.00	0.00	0.00	0.00	0.00									
Total Capacity Discount	0	0	0	0	0	0									

Equity Rate	12%	Equity Ratio	52%		
Debt Rate	6.50%	After-tax debt rate	4.0%	S&P Discount Rate	10%
Tax Rate	38.58%	Discount Rate	8.16%	S&P Risk Factor	30%

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
NPV of Future Payments	207398	197714	165329	129705	90519	47415	0	0	0	0	0	0	0	0	0
Equity Cost	4218	4021	3363	2638	1841	964	0	0	0	0	0	0	0	0	0
NPV(1/2010 $)	14893														
NPV(1/2004 $)	9304														

Pipeline Reservation	2010	2011	2012	2013	2014	2015	2016	2017
Jan-May		6.47	6.59	6.71	6.84	6.96	7.08	7.2
Jun-Dec	6.47	6.59	6.71	6.84	6.96	7.08	7.2	
Annual Average	6.47	6.54	6.66	6.79	6.91	7.03	7.15	7.2

Southern Company (thru 12/2015) F	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Scherer Cost											
Capacity (MW)											
Price ($/kW-mo)											
Franklin Cost											
Capacity (MW)											
Price ($/kW-mo)											
Pipeline Reservation ($/mmBtu-mo											
Pipeline Reservation (mmBtu-day)											
Transmission											
Price ($/kW-mo)											
Total Capacity											
Total Pipeline											
Annualized Fixed Costs											
Months											
Include Pipeline Reservation?											
Total Fixed Costs for Equity ($000)											
Price reduction											
Scherer price discount											
Franklin price discount											
Total Capacity Discount											
Equity Rate											
Debt Rate											
Tax Rate											
NPV of Future Payments	0	0	0	0	0	0	0	0	0	0	0
Equity Cost	0	0	0	0	0	0	0	0	0	0	0
NPV(1/2010 $)											
NPV(1/2004 $)											
Pipeline Reservation											
Jan-May											
Jun-Dec											
Annual Average											

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CONFIDENTIAL 04393-EI

GENERIC UNIT CHARACTERISTICS for ALL TECHNOLOGIES - *Florida* *(a)*

	A	B	C	D	E	F	G	H	I	J	K	L	M	
	Advanced Fluidized Bed *(b)*	Coal Gasification Combined Cycle		Pulverized Coal *(b)*		Combined Cycle *(2x2x1 Configuration)*		Combustion Turbines — Aero Non-augmented Nominal 45 MW		Aero Augmented Nominal 47 MW		*Frame* Nominal 80 MW		
				Sub-Crit	Super-crit									
TECHNOLOGY NAME	(annual)	(winter)	(summer)	(annual)	(annual)	(winter)	(summer)	(winter)	(summer)	(winter)	(summer)	(winter)	(summer)	
[redacted]	500	629.530	561.541	500	500	536	478	48	39	50	40	81	66	
[redacted]														
[redacted]	125	157	140	125	125	134	120	12	10	12	10	20	16	
[redacted]														
[redacted]	1000	1259	1123	1000	1000	1072	957	387	312	398	321	651	525	
Total Plant Cost/Unit ($/kW)	1,165.22	1,098.63	1,223.31	987.18	1,078.71	397.70	445.30	599.75	745.76	625.17	777.09	428.37	533.07	
Start-up ($/kW)	35.12	29.95	37.17	27.69	29.62	14.62	16.87	19.27	22.49	20.09	23.72	17.45	20.23	
Royalties ($/kW)	0.00	8.44	10.48	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
Land ($/kW)	1.00	1.08	1.34	1.34	1.27	1.15	1.15	0.23	0.23	0.20	0.20	0.13	0.13	
Inventories ($/kW)	31.84	29.99	37.23	25.29	23.70	2.35	2.83	2.95	3.64	3.08	3.80	2.23	2.76	
Total Investment ($/kW)	1,233.18	1,168.09	1,309.52	1,042.02	1,133.30	415.81	466.15	622.20	772.12	648.55	804.81	448.18	556.17	
Total Plant Cost/Unit (K$)	616,589	735,346		521,008	566,651	222,972		30,120		32,280		36,495	36,496	
Total Capital Required ($/kW)	1,384.55	1,311.47	1,470.26	1,170.06	1,273.07	453.79	508.73	657.61	816.05	685.46	850.62	476.24		10
[redacted]	34.03	32.99	36.98	29.18	31.48	2.64	2.96	4.35	5.39	4.63	5.74	2.93	3.64	11
[redacted]														
[redacted]	34.03	32.99	36.98	29.18	31.48	33.96	38.07	26.09	32.37	27.50	34.11	29.80	36.98	12
[redacted]	7.05	1.05	1.17	3.06	3.04	2.18	2.45	14.15	17.56	19.71	24.46	11.31	14.03	13
[redacted]														
[redacted]	7.05	1.05	1.17	3.06	3.04	2.18	2.45	14.15	17.56	19.71	24.46	11.31	14.03	14
Full Load Heat Rate (Btu/kWh)	9,693	8,026	8,227	9,193	8,647	7,006	7,181	9,342	9,576	9,604	10,208	11,285	11,994	15
75%	9,772	8,568	8,783	9,354	8,796	7,534	7,723	10,015	10,266	10,297	10,944	12,098	12,859	16
50%	10,322	9,956	10,206	9,841	9,251	7,014	7,190	11,407	11,693	11,727	12,465	13,778	14,645	17
25%	12,562	13,992	14,343	11,762	11,034	8,484	8,697	15,705	16,099	16,148	17,163	18,971	20,165	18
[redacted]	4.1%	10.1%	10.1%	4.1%	4.2%	6.7%	6.7%	5.2%	5.2%	5.2%	5.2%	4.7%	4.7%	19
[redacted]	3.0	2.4	2.4	5.9	5.9	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	20
Book Life (Years)	40	25	25	40	40	25	25	25	25	25	25	25	25	21
Tax Life (Years)	20	20	20	20	20	20	20	15	15	15	15	15	15	22
Construct Time (Years) *(2)*	5	5	5	5	5	3	3	2	2	2	2	2	2	23
[redacted]	1	1	1	1	1	15	15	30	30	30	30	40	40	24
	9	9	9	9	9	60	60	70	70	70	70	60	60	25
	40	40	40	40	40	25	25							26
	35	35	35	35	35									27
	15	15	15	15	15									28
[redacted]														
Levelized Fixed Charge Rate (%)	13.03%	14.35%	14.35%	13.02%	13.02%	14.11%	14.11%	13.43%	13.43%	13.43%	13.43%	13.48%	13.48%	
1st Year Charge Rate (%)	18.01%	19.61%	19.61%	18.01%	18.02%	19.17%	19.18%	18.77%	18.77%	18.77%	18.77%	18.83%	18.83%	
Cumulative PV CC (%)	152.77%	151.15%	151.15%	152.75%	152.68%	148.63%	148.63%	141.51%	141.51%	141.51%	141.51%	141.94%	141.94%	
[redacted]	0.10 sncr	0.038 wl (15 ppmv)	0.038 wl (15 ppmv)	0.104 scr	0.104 scr	0.011 dln&scr (3 ppmv)	0.011 dln&scr (3 ppmv)	0.032 dln&scr (9 ppmv)	0.032 dln&scr (9 ppmv)	0.032 wl&scr (9 ppmv)	0.032 wl&scr (9 ppmv)	0.032 dln (9 ppmv)	0.032 dln (9 ppmv)	29 30

FUEL DATA

Sulfur Removed *(4)*

Coal = 95%
CGCC = 99%
CC = 0%
CT = 0%

GLOBAL DATA *(5)*

Start Year =	2004	31
Discount Rate =	8.16%	32
Escalation Rate =	2.50%	33
M-Slope (Used For Reliability) =	274	34

NOTES

(a) Except for CC's and CT's, costs are based on TAG version 6.1 escalated to 2004$. CC and CT capital costs are based on the 2004 TAG pre-release. Max Rating
(b) Coal technologies include mercury control *costs as follows: ~$25/kW capital*, ~$1.00/kW-yr FO&M, and ~$0.12/MWh VO&M.
(c) Incremental augmentation costs are the average of Evaporative Cooling and Fogging technologies.
(d) Includes cost of generation module replacements *over 30 years*.
(e) Nuclear Decommissioning Fund costs should be modeled as escalating at the same rate as O&M up to the installation year then held constant. Back-end costs do
(f) Does NOT include impact of the "Production Tax Credit."
(1) Based on PMDb element "FL_CT & CC Assumptions_2004_0211.xls"; all rates are NON-escalating. Heat rates from Summer 2003 TAG runs.
(2) Construction times shown represent the minimum time required *to build a power plant under ideal* conditions. It includes engineering, licensing, construction start-up, & power testing, but does not include site selection and other pre-licensing activities.
(3) Patterns represent the annual construction cash flows associated with various technologies. They are in percent of overnight construction cost
(4) NOx Emission Rates and Sulfur Removal Rates are from TAG.
(5) Based on PMDb submittal "Financial_2003_1204.xls".

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DOCUMENT DATE 05062 MAY 24

GENERIC UNIT CHARACTERISTICS for ALL TECHNOLOGIES - *Florida* *(a)*

	A	B	C	D	E	F	G	H	I	J	K	
	Combustion Turbines Frame, Nominal 170 MW				Fuel Cell *(d)*	Nuclear *(e)*	Municipal Solid	Solar				
	Non-Augmented		Augmented *(c)*		Solid Oxide	ALWR-P	Waste	PV	Tires	Wind *(f)*	Wood	
TECHNOLOGY NAME	(winter)	(summer)	(winter)	(summer)	(annual)	(annual)	(annual)	(annual)	(annual)	(annual)	(annual)	
[redacted]	188	151	188	158	25	600	40	5	30	1	50	1
[redacted]	47	38	47	39	8	150	10	0	8	0.038	13	2
[redacted]	751	606	751	630	25	1200	40	50	30	7.50	50	3
Total Plant Cost/Unit ($/kW)	279.64	348.36	285.71	341.14	677.73	1,478.36	5,209.46	4,514.20	3,329.41	973.03	2,130.87	4
Start-up ($/kW)	14.27	16.42	14.27	16.42	18.67	41.78	160.02	91.12	88.11	22.09	60.36	5
Royalties ($/kW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6
Land ($/kW)	0.10	0.10	0.10	0.10	0.52	1.09	3.69	8.43	4.38	82.00	3.28	7
Inventories ($/kW)	1.74	2.13	1.74	2.13	3.39	7.39	117.69	22.57	46.81	4.87	65.59	8
Total Investment ($/kW)	295.75	367.01	301.82	359.79	700.31	1,528.61	5,490.86	4,636.32	3,468.70	1,081.99	2,260.10	9
Total Plant Cost/Unit (K$)	**55,561**		**56,702**		**17,508**	**917,168**	**219,635**	**23,182**	**104,061**	**811**	**113,005**	
Total Capital Required ($/kW)	314.25	389.97	320.70	382.30	759.10	1,841.95	6,107.00	5,025.00	3,861.00	1,165.94	2,511.00	10
[redacted]	2.17	2.69	2.17	2.59	7.57	74.12	232.50	10.11	147.44	32.10	79.32	11
[redacted]	26.37	32.72	27.00	32.19	31.24	81.53	232.50	10.11	147.44	32.10	79.32	12
[redacted]	9.94	12.33	9.94	12.36	0.05	0.57	28.38	0.00	3.95	0.00	3.20	13
[redacted]	9.94	12.33	9.94	12.36	0.05	1.57	28.38	0.00	3.95	0.00	3.20	14
Full Load Heat Rate (Btu/kWh)	10,165	10,804	10,165	10,804	5,067	10,000	16,373	--	12,366	--	13,894	15
75%	10,897	11,583	10,897	11,583	5,465	--	--	--	--	--	--	16
50%	12,410	13,191	12,410	13,191	6,193	--	--	--	--	--	--	17
25%	17,089	18,164	17,089	18,164	7,963	--	--	--	--	--	--	18
[redacted]	4.7%	4.7%	4.7%	4.7%	3.0%	7.7%	10.0%	3.0%	10.0%	3.0%	10.0%	19
	3.6	3.6	3.6	3.6	1.0	3.9	2.9	2.0	2.9	2.0	2.9	20
Book Life (Years)	25	25	25	25	30	40	20	20	20	20	30	
Tax Life (Years)	15	15	15	15	15	15	5	5	5	5	5	
Construct Time (Years) *(2)*	2	2	2	2	3	11	5	3	5	3	5	
[redacted]	40	40	40	40	6	1	5	6	5	6	5	21
	60	60	60	60	65	1	9	65	9	65	9	22
					29	1	18	29	18	29	18	23
						1	43		43		43	24
						1	25		25		25	25
						10						26
						15						27
						20						28
						20						29
						15						30
						15						31
Levelized Fixed Charge Rate (%)	13.48%	13.48%	13.48%	13.48%	16.60%	13.08%	13.48%	13.22%	13.47%	13.33%	11.98%	
1st Year Charge Rate (%)	18.83%	18.83%	18.83%	18.83%	18.40%	19.66%	20.59%	20.13%	20.62%	19.82%	18.79%	
Cumulative PV CC (%)	141.96%	141.95%	141.95%	141.96%	184.17%	153.40%	130.87%	128.29%	130.76%	129.32%	132.93%	
[redacted]	0.032 dln	0.032 dln	0.032 dln	0.032 dln	n/a	n/a	n/a	n/a	n/a	n/a	n/a	32

FUEL DATA

Sulfur Removed *(4)*
Coal = 95%
CGCC = 99%
CC = 0%
CT = 0%

GLOBAL DATA *(5)*

Start Year =	2004	33
Discount Rate =	8.16%	34
Escalation Rate =	2.50%	35
M-Slope (Used For Reliability) =	274	36

NOTES

(a) Except for CC's and CT's, costs are based on TAG version 6.1 escalated to 2004$. CC and CT capital costs are based on the 2004 TAG pre-release. Max Rating is for a single unit, not the plant. Costs are based on multiple units per site.
(b) Coal technologies include mercury control costs as follows: ~$25/kW capital, ~$1.00/kW-yr FO&M, and ~$0.12/MWh VO&M.
(c) Incremental augmentation costs are the average of Evaporative Cooling and Fogging technologies.
(d) Includes cost of generation module replacements over 30 years.
(e) Nuclear Decommissioning Fund costs should be modeled as escalating at the same rate as O&M up to the installation year then held constant. Back-end costs do not escalate.
(f) Does NOT include impact of the "Production Tax Credit."
(1) Based on PMDb element "FL_CT & CC Assumptions_2004_0211.xls"; all rates are NON-escalating. Heat rates from Summer 2003 TAG runs.
(2) Construction times shown represent the minimum time required to build a power plant under ideal conditions. It includes engineering, licensing, construction start-up, & power testing, but does not include site selection and other pre-licensing activities.
(3) Patterns represent the annual construction cash flows associated with various technologies. They are in percent of overnight construction costs.
(4) NOx Emission Rates and Sulfur Removal Rates are from TAG.
(5) Based on PMDb submittal "Financial_2003_1204.xls".

2

PHASED CONSTRUCTION COSTS for VIABLE TECHNOLOGIES - *Florida*

(Based on TAG version 6.1, Summer 2003 runs)

	A	B	C	D	E	F	
			Pulverized Coal				
	Atmospheric Fluidized Bed		Sub-Crit	Super-crit	CGCC		
COAL		Winter	Annual	Annual	Winter	Summer	
Total Investment ($/kW)	1233.18	1233.18	1042.02	1133.30	1168.09	1309.52	1
# of Units/Site	4	2	2	2	2	2	
Unit Size	250	500	500	500	629.53	561.54	2
Total Project Cost (Unit-$/kW)	4933		2084	2267	2336	2619	3
Total Plant Cost for 1st Unit ($/kW)	1395		1123	1221	1329	1490	4
Remaining Project Cost (Unit-$/kW)	3538		961	1045	1007	1129	5
# of Remaining Units	3		1	1	1	1	
Incr. Cost of Remaining Units ($/kW)	1179		961	1045	1007	1129	6
Scalar	0.884		0.928	0.928	0.879	0.879	7
Total Cost for 1st Unit (K$)	348,749	**643,559**	**561,430**	**610,615**	**836,572**	**836,575**	
Total Cost for Remaining Units (K$)	884,428	**589,619**	**480,585**	**522,686**	**634,121**	**634,124**	
TOTAL PROJECT COST (K$)	1,233,178	**1,233,178**	**1,042,015**	**1,133,302**	**1,470,693**	**1,470,699**	
Seasonal Difference					6	0.00%	

	G	H	I	J	K	L	M	N	O	P	
	Nominal 45 MW Aero Non-augmented		Nominal 47 MW Aero Augmented		Nominal 80 MW Frame Non-Augmented		Nominal 170 MW Frame Non-Augmented		Nominal 170 MW Frame Augmented		
COMBUSTION TURBINES	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	
Total Investment ($/kW)	622.200	772.120	648.549	804.814	448.180	556.174	295.750	367.012	301.822	359.792	8
# of Units/Site	8	8	8	8	8	8	4	4	4	4	
Unit Size	48.41	39.01	49.77	40.11	81.43	65.62	187.87	151.39	187.87	157.60	9
Total Project Cost (Unit-$/kW)	4978	6177	5188	6439	3585	4449	1183	1468	1207	1439	10
Total Plant Cost for 1st Unit ($/kW)	710	881	722	896	502	623	330	410	337	402	11
Remaining Project Cost (Unit-$/kW)	4267	5296	4466	5542	3084	3827	853	1058	870	1038	12
# of Remaining Units	7	7	7	7	7	7	3	3	3	3	
Incr. Cost of Remaining Units ($/kW)	610	757	638	792	441	547	284	353	290	346	13
Scalar	0.876	0.876	0.898	0.898	0.893	0.893	0.896	0.896	0.896	0.896	14
Total Plant Cost for 1st Unit (K$)	**34,384**	**34,384**	**35,947**	**35,947**	**40,868**	**40,869**	**62,011**	**62,011**	**63,284**	**63,283**	
Total Cost for Remaining Units (K$)	**206,577**	**206,579**	**222,295**	**222,295**	**251,094**	**251,096**	**160,235**	**160,236**	**163,525**	**163,524**	I-
TOTAL PROJECT COST (K$)	**240,961**	**240,963**	**258,242**	**258,242**	**291,962**	**291,965**	**222,246**	**222,246**	**226,808**	**226,807**	9-1
Seasonal Difference	5	0.00%	0	0.00%	3	0.00%	0	0.00%	2	0.00%	

	Q	R	
	Nominal 515 MW 2x2x1 Combined Cycle Non-Augmented		
COMBINED CYCLES	Winter	Summer	
Total Investment ($/kW)	415.812	466.147	15
# of Units/Site	2	2	
Unit Size	536.232	478.319	16
Total Project Cost (Unit-$/kW)	832	932	17
Total Plant Cost for 1st Unit ($/kW)	464	520	18
Remaining Project Cost (Unit-$/kW)	368	412	19
# of Remaining Units	1	1	20
Incr. Cost of Remaining Units ($/kW)	368	412	21
Scalar	0.896	0.896	22
Total Plant Cost for 1st Unit (K$)	**248,852**	**248,847**	
Total Cost for Remaining Units (K$)	**197,091**	**197,087**	
TOTAL PROJECT COST (K$)	**445,943**	**445,934**	
Seasonal Difference	9	0.00%	

NOTES:

Total Plant Cost = "Overnight" Unit Cost *plus* Owner Costs *plus* Mercury Controls Costs (if applicable). Does **NOT** include AFUDC.

Assumes the first unit is more heavily weighted and the remaining units are equally weighted.

Total Plant Cost for 1st Unit = Total Plant Cost divided by the Scalar.

Scalars are from 07/10/03 EPRI submittal.

Total Plant Costs are from the Summer 2003 TAG analysis escalated to 2004$.

CORPORATE STANDARD ASSUMPTIONS
for LONG-RANGE GENERIC PLANNING - *Florida*

	A	B	C	D	E	
	PULVERIZED COAL Sub-Critical	**COMBINED CYCLE** Nominal 170 MW CTs 2x2x1 Configuration		**SIMPLE CYCLE** Nominal 170 MW Augmented FRAME		
	annual	winter	summer	winter	summer	
Net Unit Capacity, MAX (MW)	500	536.232	478.32	187.866	157.596	1
Number of Units/Plant	2	2	2	4	4	
Total Plant Cost/Unit ($/kW)	987.18	397.70	445.30	285.71	341.14	2
Start-up ($/kW)	27.69	14.62	16.87	14.27	16.42	3
Royalties ($/kW)	0.52	0.00	0.00	0.00	0.00	4
Land ($/kW)	1.34	1.15	1.15	0.10	0.10	5
Inventories ($/kW)	25.29	2.35	2.83	1.74	2.13	6
Total Investment ($/kW)	1,042.02	415.81	466.15	301.82	359.79	7
Total Plant Cost/Unit (K$)	521,008	222,972		56,702		
Fixed O&M ($/kW-Yr)	29.18	2.64	2.96	2.17	2.59	8
Book Life (Years)	40	25		25		
Tax Life (Years)	20	20		15		
Construct Time (Years)	5	3		2		
Cash Flow (%/Yr)	1	15		40		9
	9	60		60		10
	40	25				11
	35					12
	15					13

NOTES:

1) This information was developed for long-range resource planning applications. Use for any other purpose should be checked by Resource Planning Unit to determine appropriateness.

2) All costs are "overnight" and do not include AFUDC. Except for CC's and CT's, costs are based on TAG version 6.1 escalated to 2004$. CC and CT capital costs are based on the 2004 TAG pre-release. Max Rating is for a single unit, not the plant. Costs are based on multiple units per site.

3) Construction times shown represent the minimum time required to build a power plant under ideal conditions. It includes engineering, licensing, construction start-up, & power testing, but does not include site selection and other pre-licensing activities.

4) Patterns represent the *annual construction cash flows* associated with various technologies. They are in percent of overnight construction costs.

5) Coal technologies include mercury control costs as follows: ~$25/kW capital, ~$1.00/kW-yr FO&M, and ~$0.12/MWh VO&M.

DATE	NOTES
04/07/04	Copy of FL_Generic Unit Char_2004_0405.xls. Recalculated FO&M and VO&M for CGCC and CC to correspond to summer rating changes that were previously made based on Hines CC4 summer:winter ratios.

Please click on the link below for the assumptions file:
FL_Generic Unit Assumptions_2004_0407.doc