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GULF POWER
A SOUTHERN COMPANY

August 3, 2009

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COMMISSION CLERK

Ms. Ann Cole, Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee FL 32399-0870

Dear Ms. Cole:

Enclosed for official filing in Docket No. 090001-EI is an original and fifteen copies of the following:

1. Prepared direct testimony of H. R. Ball.
2. Prepared direct testimony and exhibit of R. W. Dodd.
3. Risk Management Plan for Fuel Procurement

Sincerely,

Susan D. Ritenour (lw)

mr

Enclosures

cc: Beggs & Lane
Jeffrey A. Stone, Esq.

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ECR
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SSC
SGA 2
ADM
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: **Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor**)

Docket No.: **090001-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by U. S. mail this 3rd day of August, 2009, on the following:

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GULF POWER COMPANY

Before the Florida Public Service Commission

Prepared Direct Testimony of

H. R. Ball

Docket No. 090001-EI

Date of Filing: August 4, 2009

Q. Please state your name and business address.

A. My name is H. R. Ball. My business address is One Energy Place, Pensacola, Florida 32520-0335. I am the Fuel Manager for Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of Southern Mississippi in Hattiesburg, Mississippi in 1978 with a Bachelor of Science Degree in Chemistry and graduated from the University of Southern Mississippi in Long Beach, Mississippi in 1988 with a Masters of Business Administration. My employment with the Southern Company began in 1978 at Mississippi Power's (MPC) Plant Daniel as a Plant Chemist. In 1982, I transferred to MPC's Fuel Department as a Fuel Business Analyst. I was promoted in 1987 to Supervisor of Chemistry and Regulatory Compliance at Plant Daniel. I was promoted to Supervisor of Coal Logistics with Southern Company Fuel Services in Birmingham, Alabama in 1998. My responsibilities included administering coal supply and transportation agreements and managing the coal inventory program for the Southern Electric System. I transferred to my current position as Fuel Manager for Gulf Power Company in 2003.

Q. What are your duties as Fuel Manager for Gulf Power Company?

A. I manage the Company's fuel procurement, inventory, transportation, budgeting, contract administration, and quality assurance programs to ensure that the generating plants operated by Gulf Power are supplied with an adequate quantity of fuel in a timely manner and at the lowest practical cost. I also have responsibility for the administration of Gulf's Intercompany Interchange Contract (IIC).

Q. What is the purpose of your testimony in this docket?

A. The purpose of my testimony is to compare Gulf Power Company's original projected fuel and net power transaction expense and purchased power capacity costs with current estimated/actual costs for the period January 2009 through December 2009 and to summarize any noteworthy developments at Gulf in these areas. The current estimated/actual costs consist of actual expenses for the period January 2009 through June 2009 and projected fuel and net power transaction costs for July 2009 through December 2009. Projected capacity costs for July 2009 through December 2009 remain as originally filed. It is also my intent to be available to answer questions that may arise among the parties to this docket concerning Gulf Power Company's fuel and net power transaction expenses, and purchased power capacity costs.

Q. During the period January 2009 through December 2009 how will Gulf Power Company's recoverable total fuel and net power transactions cost compare with the original cost projection?

A. Gulf's currently projected recoverable total fuel and net power transactions cost for the period is $563,071,299 which is $95,097,609 or 14.45% below the original projected amount of $658,168,908. The resulting average fuel cost is projected to be 4.6605 cents per KWH or 6.84% below the original projection of 5.0025 cents per KWH. The lower total fuel expense and average per unit fuel cost is attributed to a combination of lower than projected fuel prices for the period which are reflected in both the fuel cost of generated power and the fuel cost of purchased power and a lower amount of energy (KWH) supplied. This current projection of fuel and net purchased power transaction cost is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 21.

Q. During the period January 2009 through December 2009 how will Gulf Power Company's recoverable fuel cost of generated power compare with the original projection of fuel cost?

A. Gulf's currently projected recoverable fuel cost of generated power for the period is $601,876,572 which is $216,654,336 or 26.47% below the original projected amount of $818,530,908. Total generation is expected to be 13,845,714,100 KWH compared to the original projected generation of 16,325,840,000 KWH or 15.19% below original projections. The resulting average fuel cost is expected to be 4.3740 cents per KWH or 13.30% below the original projected amount of 5.0137 cents per KWH. This current projection of fuel cost of system net generation is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 6.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of generated power and the current projection?

A. The lower total fuel expense is due to lower than originally projected quantity of generated power (KWH) and lower average per unit fuel costs (cents/KWH). Delivered coal and natural gas prices per MMBTU are projected to be below original projections for the period due to changes in market fuel prices and a change in the mix of generating units operating to meet load. The quantity of contract coal shipments for the period is expected to be below original projections due to a reduction in the quantity of coal burned. Coal burn is lower due to a combination of lower demand for generated power and reduced economic dispatch of coal fired units. Market prices for natural gas and oil for the period are expected to be lower than original projections. Supply and demand imbalances in the oil and gas markets have driven the price for these fossil fuel sources lower and prices are expected to remain lower for the rest of the period. The quantity of natural gas burn is expected to be above original projections in response to the lower market prices for natural gas increasing economic dispatch of gas fired generation. The ability to change the mix of generating units operating to meet customer demand to a more heavily weighted natural gas mix has allowed Gulf to take advantage of lower natural gas prices.

Q How did the total projected fuel cost of system net generation compare to the actual cost for the first six months of 2009?

A. The total fuel cost of system net generation for the first six months of 2009 was $235,971,280 which is $141,791,530 or 37.53% lower than the projection of $377,762,810. On a fuel cost per KWH basis, the actual cost was 3.85 cents per KWH, which is 14.63% lower than the projected cost of 4.51 cents per KWH. This lower cost of system generation on a cents per KWH basis is due to a combination of fuel cost in $/MMBTU being 11.60% lower than projected and heat rate (BTU/KWH) of the generating units operating being 3.35% lower than projected. This information is found on Schedule A-3 of the June 2009 Monthly Fuel Filing.

Q. How did the total projected cost of coal burned compare to the actual cost for the first six months of 2009?

A. The total cost of coal burned (including boiler lighter) for the first six months of 2009 was $167,725,292 which is $94,139,810 or 35.95% lower than our projection of $261,865,102. On a fuel cost per KWH basis, the actual cost was 3.96 cents per KWH which is 7.03% higher than the projected cost of 3.70 cents per KWH. The lower than projected total cost of coal burned (including boiler lighter) is due to total MMBTU of coal burn being 38.14% below the estimated burn for the period. The higher per KWH cost of coal fired generation is due to actual coal prices (including boiler lighter) being 3.63% higher than projected on a $/MMBTU basis and the weighted average heat rate (BTU/KWH) of the coal fired generating units operating being 3.28% higher than projected. This information is found on Schedule

A-3 of the June 2009 Monthly Fuel Filing. Gulf has fixed price coal contracts in place for the period to limit price volatility and ensure reliability of supply. Actual average prices for coal purchased during the period are higher due to a change in the timing of contract shipments to Gulf's coal fired generating plants. A significant amount of these contract coal shipments have been deferred to later periods in response to lower coal burn. Another factor contributing to the higher cost of coal fired generation (cents/KWH) is that weighted average coal unit heat rates are higher than projected for the period. Generating unit heat rates have been impacted by the percentage of time these units operated at lower than projected loads. When generating units operate at lower loads, unit efficiency is reduced.

Q. How did the total projected cost of natural gas burned compare to the actual cost during the first six months of 2009?

A. The total cost of natural gas burned for generation for the first six months of 2009 was $68,215,969 which is $47,681,739 or 41.14% lower than Gulf's projection of $115,897,708. The total cost of natural gas burned for generation is lower than projected due to the market price of natural gas being lower than projected. Market prices for natural gas are lower due to decreased demand for natural gas and other fossil fuels. On a cost per unit basis, the actual cost of gas fired generation was 3.61 cents per KWH which is 59.35% lower than the projected cost of 8.88 cents per KWH. Actual natural gas prices were $5.08 per MMBTU or 59.59% lower than the projected cost of $12.57 per MMBTU. This information is found on Schedule A-3 of the June 2009 Monthly Fuel Filing.

Q. For the period in question, what volume of natural gas was actually hedged using a fixed price contract or instrument?

A. Gulf Power financially hedged 5,080,000 MMBTU of natural gas for the period January 2009 through June 2009 using fixed price financial swaps. This equates to 38.5% of the actual natural gas burn for the period.

Q. What types of hedging instruments were used by Gulf Power Company and what type and volume of fuel was hedged by each type of instrument?

A. Natural gas was hedged using financial swaps that fixed the price of gas to a certain price. These swaps settled against either a NYMEX Last Day price or Gas Daily price. The entire amount (5,080,000 MMBTU) of gas hedged was hedged using these financial instruments.

Q. What was the actual total cost (e.g., fees, commission, option premiums, futures gains and losses, swap settlements) associated with each type of hedging instrument?

A. No fees, commission, or option premiums were paid. Gulf's gas hedging program has resulted in a net financial loss of $25,233,414 for the period January through June 2009. This information is found on Schedule A-1, Period to Date, line 2 of the June 2009 Monthly Fuel Filing.

Q. During the period January 2009 through December 2009 how will Gulf Power Company's recoverable fuel cost of power sold compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost and gains on power sales for the period is $93,156,965 or 64.06% below the original projected amount of $259,233,000. Total megawatt hours of power sales is expected to be 3,492,249,334 KWH compared to the original projection of 4,300,511,000 KWH or 18.79% below projections. The resulting average fuel cost and gains on power sales is expected to be 2.6675 cents per KWH or 55.75% below the original projected amount of 6.0280 cents per KWH. This current projection of fuel cost of power sold is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 19.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost and gains on power sales and the current projection?

A. The lower total credit to fuel expense from power sales is attributed to a combination of a lower quantity of power sales made than originally projected and a lower fuel reimbursement rate for these sales. Demand for energy has declined due to overall economic conditions being below the original forecast for the period. Lower market prices for coal and natural gas during the period have decreased the fuel reimbursement rate (cents/KWH) for power sales that have been made.

Q. How did the total projected fuel cost of power sold compare to the actual cost for the first six months of 2009?

A. The total fuel cost of power sold for the first six months of 2009 was $29,199,965 which is $113,411,035 or 79.52% less than our projection of $142,611,000. On a fuel cost per KWH basis, the actual cost was 1.9014 cents per KWH which is 68.18% below the projected cost of 5.9747 cents per KWH. This information is found on Schedule A-1, Period to Date, line 19 of the June 2009 Monthly Fuel Filing.

Q. During the period January 2009 through December 2009 how will Gulf Power Company's recoverable fuel cost of purchased power compare with the original cost projection?

A. Gulf's currently projected recoverable fuel cost of purchased power for the period is $54,351,693 or 45.03% below the original projected amount of $98,871,000. The total amount of purchased power is expected to be 1,728,416,302 KWH compared to the original projection of 1,131,523,000 KWH or 52.75% above projections. The resulting average fuel cost of purchased power is expected to be 3.1446 cents per KWH or 64.01% below the original projected amount of 8.7379 cents per KWH. This current projection of fuel cost of purchased power is captured in the exhibit to Witness Dodd's testimony, Schedule E-1 B-1, Line 13.

Q. What are the reasons for the difference between Gulf's original projection of the fuel cost of purchased power and the current projection?

A. The lower total fuel cost of purchased power is attributed to a combination of Gulf purchasing a greater amount of energy to supplement its own generation to meet load demands but at a significantly lower price per

KWH than originally projected. Replacement fuel costs for purchased power are lower as a result of the estimated/actual natural gas market prices being lower than originally projected for the period. Lower demand for energy in the overall economy has greatly increased the availability of lower cost purchased power. Gulf has been able to take advantage of the availability of low cost power by increasing purchases of power in the market.

Q. How did the total projected fuel cost of purchased power compare to the actual cost for the first six months of 2009?

A. The total fuel cost of purchased power for the first six months of 2009 was $31,060,695 which is $8,270,695 or 36.29% higher than our projection of $22,790,000. The higher than anticipated purchased power expense is due to the actual quantity of purchases being 334.62% higher than projected. Purchase power quantity is higher due to the lower price of available power making it the economic choice for providing energy to the customer during certain periods of time. On a fuel cost per KWH basis, the actual cost was 2.7555 cents per KWH which is 68.64% lower than the projected cost of 8.7871 cents per KWH. This information is found on Schedule A-1, Period to Date, line 12 of the June 2009 Monthly Fuel Filing.

Q. Were there any other significant developments in Gulf's fuel procurement program during the period?

A. No.

Q. Were Gulf Power's actions through June 30 2009 to mitigate fuel and purchased power price volatility through implementation of its financial and/or physical hedging programs prudent?

A. Yes. Gulf's physical and financial fuel hedging programs have resulted in more stable fuel prices. Over the long term, Gulf anticipates less volatile future fuel costs than would have otherwise occurred if these programs had not been utilized.

Q. Should Gulf's fuel and net power transactions cost for the period be accepted as reasonable and prudent?

A. Yes. Gulf has followed its Risk Management Plan for Fuel Procurement in securing the fuel supply for its electric generating plants. Gulf's coal supply program is based on a mixture of long-term contracts and spot purchases at market prices. Coal suppliers are selected using procedures that assure reliable coal supply, consistent quality, and competitive delivered pricing. The terms and conditions of coal supply agreements have been administered appropriately. Natural gas is purchased using agreements that tie price to published market index schedules and is transported using a combination of firm and interruptible gas transportation agreements. Natural gas storage is utilized to assure that natural gas is available during times when gas supply is curtailed or unavailable. Gulf's fuel oil purchases were made from qualified vendors using an open bid process to assure competitive pricing and reliable supply. Gulf makes sales of power when available and gets reimbursed at the marginal cost of replacement fuel. This fuel reimbursement is credited back to the fuel cost recovery clause so that lower cost fuel purchases made on behalf of Gulf's customers remain to the benefit of those customers. Gulf purchases power when necessary to meet customer load requirements and when the cost of purchased power is expected to be less than the cost of system generation. The fuel cost of purchased power is the lowest cost available in the market at the time of purchase to meet Gulf's load requirements.

Q. During the period January 2009 through December 2009, what is Gulf's projection of actual / estimated net purchased power capacity transactions and how does it compare with the company's original projection of net capacity transactions?

A. As shown on Line 4 of Schedule CCE-1b in the exhibit to Witness Dodd's testimony, Gulf's total current net capacity payment projection for the January 2009 through December 2009 recovery period is $33,879,164. Gulf's original projection for the period was $34,921,268 and is shown on Line 3 of Schedule CCE-1 filed September 2, 2008. The difference between these projections is $1,042,104 or 2.98% lower than the original projection of net capacity payments. Actual capacity payments during the first six months of 2009 were lower than projected for the period due to Gulf's higher level of capacity (MW) reserves that reduced its capacity purchase requirements.

Q. Mr. Ball, does this complete your testimony?

A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 090001-EI

Before me the undersigned authority, personally appeared H. R. Ball, who being first duly sworn, deposes, and says that he is the Fuel Manager at Gulf Power Company, a Florida corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

H R Ball

H. R. Ball
Fuel Manager

Sworn to and subscribed before me this 3rd day of August, 2004

Connie Happney

Notary Public, State of Florida at Large

Commission Number: 719129

Commission Expires: 25 January 12

CONNIE L. HAPPNEY
MY COMMISSION EXPIRES
January 25, 2012
#DD 719129
Bonded thru Notary Public Underwriters
NOTARY PUBLIC, STATE OF FLORIDA

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE

Docket No. 090001-EI

PREPARED DIRECT TESTIMONY AND EXHIBIT OF

RICHARD W. DODD

2009
ESTIMATED/ACTUAL TRUE-UP
JANUARY – JUNE ACTUAL
JULY – DECEMBER ESTIMATED

AUGUST 4, 2009

GULF POWER

A SOUTHERN COMPANY

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Richard W. Dodd
Docket No. 090001-EI
Date of Filing: August 4, 2009

Q. Please state your name, business address and occupation.

A. My name is Richard Dodd. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the Supervisor of Rates and Regulatory Matters at Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from the University of West Florida in Pensacola, Florida in 1991 with a Bachelor of Arts Degree in Accounting. I also received a Bachelor of Science Degree in Finance in 1998 from the University of West Florida. I joined Gulf Power in 1987 as a Co-op Accountant and worked in various areas until I joined the Rates and Regulatory Matters area in 1990. After spending one year in the Financial Planning area, I transferred to Georgia Power Company in 1994 where I worked in the Regulatory Accounting department and in 1997 I transferred to Mississippi Power Company where I worked in the Rate and Regulation Planning department for six years followed by one year in Financial Planning. In 2004 I returned to Gulf Power Company working in the General Accounting area as Internal Controls Coordinator. In 2007 I was promoted to Internal Controls Supervisor and in July 2008, I assumed my current position in the Rates and Regulatory Matters area.

My responsibilities include supervision of: tariff administration, cost of service activities, calculation of cost recovery factors, and the regulatory filing function of the Rates and Regulatory Matters Department.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes, I have.

Counsel: We ask that Mr. Dodd's Exhibit consisting of fourteen schedules be marked as Exhibit No. ____ (RWD-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2009 through December 2009 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2009 through December 2009 set forth in your exhibit?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?

A. In each case, the estimated true-up calculations include six months of actual data and six months of estimated data.

Q. Mr. Dodd, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2010 through December 2010?

A. The fuel cost recovery true-up for this period is an increase of 0.1098¢/kwh.

As shown on Schedule E-1A, this includes an estimated over-recovery for the January through December 2009 period of $36,414,908. It also includes a final under-recovery for the January through December 2008 period of $48,757,977 (see Schedule 1 of Exhibit RWD-1 in this docket filed on March 9, 2009). The resulting total under-recovery of $12,343,069 will be included for recovery during 2010.

Q. Mr. Dodd, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCE-1A, CCE-1B and CCE-4 of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2010 through December 2010 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2010 through December 2010?

A. The true-up for this period is an increase of 0.0099¢/kwh as shown on Schedule CCE-1A. This includes an estimated under-recovery of $1,787,568 for January 2009 through December 2009. It also includes a final over-recovery of $680,158 for the period of January 2008 through December 2008 (see Schedule CCA-1 of Exhibit RWD-1 in this docket filed March 9, 2009). The resulting total under-recovery of $1,107,410 will be included for recovery during 2010.

Q. Mr. Dodd, does this conclude your testimony?
A. Yes.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 090001-EI

BEFORE me, the undersigned authority, personally appeared Richard W. Dodd, who being first duly sworn, deposes and says that he is the Supervisor of Rates and Regulatory Matters at Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Richard W. Dodd

Richard W. Dodd
Supervisor of Rates and Regulatory Matters

Sworn to and subscribed before me
this 31st day of August, 2009.

Linda C. Webb

Notary Public, State of Florida at Large

(SEAL)

LINDA C. WEBB
Notary Public-State of Florida
Comm. Exp. May 31, 2010
Comm. No. DD 541216

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2009 - DECEMBER 2009

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2009 (Sch. E-1B, page 2, line C9)	$36,414,908
2.	Final over/(under)-recovery JANUARY - DECEMBER 2008 (EXHIBIT No.____(RWD-1) Schedule 1, line 3)	(48,757,977)
3.	Total over/(under)-recovery (Lines 1 + 1A + 2) To be included in JANUARY 2010 - DECEMBER 2010 (Schedule E1, Line 29)	($12,343,069)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY - DECEMBER 2010	11,240,618,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.1098

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

				JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		38,807,601.18	30,213,099.12	32,110,511.86	40,821,730.81	47,999,708.94	44,780,283.70	$234,732,935.61
	1a	Fuel Cost of Hedging Settlement		3,803,955.00	4,173,375.00	3,233,845.00	4,448,560.00	3,920,849.00	5,652,830.00	25,233,414.00
	2	Fuel Cost of Power Sold		(5,383,517.54)	(3,548,358.20)	(3,316,500.35)	(7,435,302.51)	(5,945,289.74)	(3,570,991.69)	(29,199,960.03)
	3	Fuel Cost of Purchased Power		4,441,832.08	7,623,480.57	3,817,197.79	1,487,485.68	2,145,378.31	9,275,775.32	28,791,149.75
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	3b	Energy Payments to Qualified Facilities		470,949.00	524,577.00	604,589.00	291,315.00	16,017.00	362,096.00	2,269,543.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	0.00
	5	Other Generation		201,574.82	195,677.39	160,783.13	176,952.13	232,004.58	271,350.72	1,238,342.77
	6	Adjustments to Fuel Cost *		67,726.12	53,326.61	35,416.10	28,692.12	58,560.22	1,867.98	245,589.15
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$42,410,120.66	$39,235,177.49	$36,645,842.53	$39,819,433.23	$48,427,228.31	$56,773,212.03	$263,311,014.25
B	1	Jurisdictional KWH Sales		840,942,442	748,132,497	754,313,308	778,555,716	925,257,949	1,174,340,944	5,221,542,856
	2	Non-Jurisdictional KWH Sales		31,682,137	27,827,610	26,339,621	25,396,931	30,492,922	37,935,600	179,674,821
	3	TOTAL SALES (Lines B1 + B2)		872,624,579	775,960,107	780,652,929	803,952,647	955,750,871	1,212,276,544	5,401,217,677
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.3693%	96.4138%	96.6259%	96.8410%	96.8095%	96.8707%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$48,077,504.05	$42,818,981.87	$43,124,951.34	$44,528,871.28	$52,938,340.31	$67,312,519.45	$298,801,168.30
	2	True-Up Provision		(3,997,794.08)	(3,997,794.08)	(3,997,794.08)	(3,997,794.08)	(3,997,794.08)	(3,997,794.08)	(23,986,764.48)
	2a	Incentive Provision		36,114.41	36,114.41	36,114.41	36,114.41	36,114.41	36,114.41	216,686.46
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$44,115,824.38	$38,857,302.20	$39,163,271.67	$40,567,191.61	$48,976,660.64	$63,350,839.78	$275,031,090.28
	4	Fuel & Net Power Transactions (Line A7)		$42,410,120.66	$39,235,177.49	$36,645,842.53	$39,819,433.23	$48,427,228.31	$56,773,212.03	$263,311,014.25
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)		40,898,945.64	37,854,605.24	35,434,161.72	38,588,530.41	46,914,975.10	55,035,105.53	$254,726,323.64
	6	Over/(Under) Recovery (Line C3-C5)		3,216,878.74	1,002,696.96	3,729,109.95	1,978,661.20	2,061,685.54	8,315,734.25	$20,304,766.64
	7	Interest Provision	(2)	(51,590.79)	(55,897.77)	(43,772.13)	(29,285.18)	(19,845.43)	(15,934.02)	($216,325.32)
	8	Adjustments		0	0	0	0	0	0	$0.00
	9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2009 - JUNE 2009								$20,088,441.32

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note 1: Revenues for January through December based on the current approved 2009 Fuel Factor excluding revenue taxes c 5.7239 ¢/KWH

Note 2: Interest Calculated for July through December at June 2009 monthly rate of 0.0292%

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2009 Est/Act True-up
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CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

				JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation		57,548,957.00	57,913,805.00	54,215,861.00	43,916,756.00	46,615,775.00	57,839,963.00	$552,784,052.61
	1a	Fuel Cost of Hedging Settlement		6,493,000.00	4,172,000.00	2,479,000.00	2,649,000.00	2,267,000.00	1,564,000.00	$44,857,414.00
	2	Fuel Cost of Power Sold		(10,573,000.00)	(10,594,000.00)	(10,703,000.00)	(8,862,000.00)	(11,043,000.00)	(12,182,000.00)	($93,156,960.03)
	3	Fuel Cost of Purchased Power		5,918,000.00	5,400,000.00	4,418,000.00	3,785,000.00	1,891,000.00	1,879,000.00	$52,082,149.75
	3a	Demand & Non-Fuel Cost Of Purchased Power		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	3b	Energy Payments to Qualified Facilities		0.00	0.00	0.00	0.00	0.00	0.00	$2,269,543.00
	4	Energy Cost of Economy Purchases		0.00	0.00	0.00	0.00	0.00	0.00	$0.00
	5	Other Generation		427,756.00	427,756.00	413,996.00	481,225.00	465,745.00	534,695.00	$3,989,515.77
	6	Adjustments to Fuel Cost *		0.00	0.00	0.00	0.00	0.00	0.00	$245,589.15
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$59,814,713.00	$57,319,561.00	$50,823,857.00	$41,969,981.00	$40,196,520.00	$49,635,658.00	$563,071,304.25
B	1	Jurisdictional KWH Sales		1,155,743,000	1,152,972,000	988,922,000	849,588,000	750,196,000	867,182,000	10,986,145,856
	2	Non-Jurisdictional KWH Sales		38,430,000	39,237,000	33,510,000	30,314,000	28,125,000	32,132,000	381,422,821
	3	TOTAL SALES (Lines B1 + B2)		1,194,173,000	1,192,209,000	1,022,432,000	879,902,000	778,321,000	899,314,000	11,367,568,677
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.7819%	96.7089%	96.7225%	96.5548%	96.3865%	96.4271%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$66,153,573.58	$65,994,964.31	$56,604,906.36	$48,629,567.53	$42,940,468.84	$49,636,630.50	$628,761,279.42
	2	True-Up Provision		(3,997,794.08)	(3,997,794.08)	(3,997,794.08)	(3,997,794.08)	(3,997,794.08)	(3,997,794.12)	($47,973,529.00)
	2a	Incentive Provision		36,114.41	36,114.41	36,114.41	36,114.41	36,114.41	36,114.46	$433,372.97
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$62,191,893.91	$62,033,284.64	$52,643,226.69	$44,667,887.86	$38,978,789.17	$45,674,950.84	$581,221,123.39
	4	Fuel & Net Power Transactions (Line A7)		$59,814,713.00	$57,319,561.00	$50,823,857.00	$41,969,981.00	$40,196,520.00	$49,635,658.00	$563,071,304.25
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)		57,930,338.59	55,471,920.11	49,192,515.76	40,552,398.04	38,771,139.56	47,895,729.13	$544,540,364.83
	6	Over/(Under) Recovery (Line C3-C5)		4,261,555.32	6,561,364.53	3,450,710.93	4,115,489.82	207,649.61	(2,220,778.29)	$36,680,758.56
	7	Interest Provision	(2)	(14,169.78)	(11,426.41)	(8,800.63)	(6,531.18)	(4,734.55)	(3,862.49)	($265,850.36)
	8	Adjustments		0	0	0	0	0	0	$0.00
	9	TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2009 - DECEMBER 2009								$36,414,908.20

* (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.

Note 1: Revenues for January through December based on the current approved 2009 Fuel Factor excluding revenue taxes c 5.7239 ¢/KWH

Note 2: Interest Calculated for July through December at June 2009 monthly rate of 0.0292%

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	DIFFERENCE %	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	DIFFERENCE %
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation	552,784,053	812,208,413	(259,424,360)	(31.94)	13,765,691,600	16,213,300,000	(2,447,608,400)	(15.10)	4.0157	5.0095	(0.9938)	(19.84)
1a	Fuel Cost of Hedging Settlement	44,857,414	0	44,857,414	100.00	0	0	0	0.00	#N/A	0.0000	#N/A	#N/A
2	Hedging Support Costs	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
3	Coal Car Investment	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
4	Other Generation	3,989,516	6,322,495	(2,332,979)	(36.90)	80,022,500	112,540,000	(32,517,500)	(28.89)	4.9855	5.6180	(0.6325)	(11.26)
5	Adjustments to Fuel Cost ***	245,589	0	245,589	100.00								
6	TOTAL COST OF GENERATED POWER	601,876,572	818,530,908	(216,654,336)	(26.47)	13,845,714,100	16,325,840,000	(2,480,125,900)	(15.19)	4.3470	5.0137	(0.6667)	(13.30)
7	Fuel Cost of Purchased Power (Exclusive of Economy)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
8	Energy Cost of Schedule C&X Econ. Purchases (Broker)	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
9	Energy Cost of Other Economy Purchases (Nonbroker)	52,082,150	98,871,000	(46,788,850)	(47.32)	1,688,697,302	1,131,523,000	557,174,302	49.24	3.0842	8.7379	(5.6537)	(64.70)
10	Energy Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
11	Capacity Cost of Schedule E Economy Purchases	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
12	Energy Payments to Qualifying Facilities	2,269,543	0	2,269,543	100.00	39,719,000	0	39,719,000	100.00	5.7140	0.0000	5.7140	100.00
13	TOTAL COST OF PURCHASED POWER	54,351,693	98,871,000	(44,519,307)	(45.03)	1,728,416,302	1,131,523,000	596,893,302	52.75	3.1446	8.7379	(5.5933)	(64.01)
14	Total Available KWH (Line 6 + Line 13)	656,228,264	917,401,908	(261,173,644)	(28.47)	15,574,130,402	17,457,363,000	(1,883,232,598)	(10.79)				
15	Fuel Cost of Economy Sales	(2,907,382)	(21,688,000)	18,780,618	(86.59)	(67,180,491)	(266,600,000)	199,419,509	(74.80)	4.3277	8.1350	(3.8073)	(46.80)
16	Gain on Economy Sales	(799,057)	(2,321,000)	1,521,943	(65.57)	0	0	0	0.00	#N/A	#N/A	#N/A	#N/A
17	Fuel Cost of Unit Power Sales	(34,613,729)	(50,109,000)	15,495,271	(30.92)	(1,515,473,172)	(1,644,994,000)	129,520,828	(7.87)	2.2840	3.0462	(0.7622)	(25.02)
18	Fuel Cost of Other Power Sales	(54,836,797)	(185,115,000)	130,278,203	(70.38)	(1,909,595,671)	(2,388,917,000)	479,321,329	(20.06)	2.8716	7.7489	(4.8773)	(62.94)
19	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 15+16+17+18)	(93,156,965)	(259,233,000)	166,076,035	(64.06)	(3,492,249,334)	(4,300,511,000)	808,261,666	(18.79)	2.6675	6.0280	(3.3605)	(55.75)
20	Net Inadvertent Interchange	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
21	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 6+13+19+20)	563,071,299	658,168,908	(95,097,609)	(14.45)	12,081,881,068	13,156,852,000	(1,074,970,932)	(8.17)	4.6605	5.0025	(0.3420)	(6.84)
22	Net Unbilled Sales	0	0	0	0.00	0	0	0	0.00	0.0000	0.0000	0.0000	0.00
23	Company Use *	975,031	1,243,071	(268,040)	(21.56)	20,921,163	24,849,000	(3,927,838)	(15.81)	4.6605	5.0025	(0.3420)	(6.84)
24	T & D Losses *	32,315,494	38,194,738	(5,879,244)	(15.39)	693,391,129	763,513,000	(70,121,872)	(9.18)	4.6605	5.0025	(0.3420)	(6.84)
25	TERRITORIAL (SYSTEM) SALES	563,071,299	658,168,908	(95,097,609)	(14.45)	11,367,568,777	12,368,490,000	(1,000,921,223)	(8.09)	4.9533	5.3213	(0.3680)	(6.92)
26	Wholesale Sales	18,911,846	22,984,344	(4,072,498)	(17.72)	381,422,821	431,931,000	(50,508,179)	(11.69)	4.9582	5.3213	(0.3631)	(6.82)
27	Jurisdictional Sales	544,159,453	635,184,564	(91,025,111)	(14.33)	10,986,145,956	11,936,559,000	(950,413,044)	(7.96)	4.9531	5.3213	(0.3682)	(6.92)
27a	Jurisdictional Loss Multiplier	1.0007	1.0007										
28	Jurisdictional Sales Adj. for Line Losses (Line 27 x 1.0007)	544,540,365	635,629,193	(91,088,828)	(14.33)	10,986,145,956	11,936,559,000	(950,413,044)	(7.96)	4.9566	5.3251	(0.3685)	(6.92)
29	TRUE-UP **	47,973,529	47,973,529	0	0.00	10,986,145,956	11,936,559,000	(950,413,044)	(7.96)	0.4367	0.4019	0.0348	8.66
30	TOTAL JURISDICTIONAL FUEL COST	592,513,894	683,602,722	(91,088,828)	(13.32)	10,986,145,956	11,936,559,000	(950,413,044)	(7.96)	5.3933	5.7270	(0.3337)	(5.83)
31	Revenue Tax Factor									1.00072	1.00072		
32	Fuel Factor Adjusted for Revenue Taxes									5.3972	5.7311	(0.3339)	(5.83)
33	GPIF Reward / (Penalty) **	(433,685)	(433,685)	0	0.00	10,986,145,956	11,936,559,000	(950,413,044)	(7.96)	(0.0039)	(0.0036)	(0.0003)	(8.33)
34	Fuel Factor Adjusted for GPIF Reward / (Penalty)									5.3933	5.7275	(0.3342)	(5.84)
35	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									5.3930	5.7280	(0.3350)	(5.85)

* Included for Informational Purposes Only
** ¢/KWH Calculation Based on Jurisdictional KWH Sales
*** (Gain)/Loss on sales of natural gas and costs of contract dispute litigation.
Note: Amounts Included in the Estimated/Actual Column represent 6 months actual and 6 months estimate.

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

LINE	LINE DESCRIPTION	(a) JANUARY ACTUAL	(b) FEBRUARY ACTUAL	(c) MARCH ACTUAL	(d) APRIL ACTUAL	(e) MAY ACTUAL	(f) JUNE ACTUAL	(g) JULY ESTIMATED	(h) AUGUST ESTIMATED	(i) SEPTEMBER ESTIMATED	(j) OCTOBER ESTIMATED	(k) NOVEMBER ESTIMATED	(l) DECEMBER ESTIMATED	(m) TOTAL
	$													
1	Fuel Cost of System Generation	38,807,601.18	30,213,099.12	32,110,511.86	40,821,730.81	47,999,708.94	44,780,283.70	57,548,957	57,913,805	54,215,861	43,916,756	46,615,775	57,839,963	552,784,052.61
1a	Other Generation	201,574.82	195,677.39	160,783.13	176,952.13	232,004.58	271,350.72	427,756	427,756	413,996	481,225	465,745	534,695	3,989,515.77
2	Fuel Cost of Power Sold	(5,383,517.54)	(3,548,358.20)	(3,316,500.35)	(7,435,302.51)	(5,945,289.74)	(3,570,991.69)	(10,573,000)	(10,594,000)	(10,703,000)	(8,862,000)	(11,043,000)	(12,182,000)	(93,156,960.03)
3	Fuel Cost of Purchased Power	4,441,831.52	7,623,481.22	3,817,198.53	1,487,485.26	2,145,377.49	9,275,774.99	5,918,000	5,400,000	4,418,000	3,785,000	1,891,000	1,879,000	52,082,149.01
3a	Demand & Non-Fuel Cost of Pur Power	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0.00
3b	Qualifying Facilities	470,949.56	524,576.35	604,588.26	291,316.00	16,017.00	362,096.00	0	0	0	0	0	0	2,269,543.17
4	Energy Cost of Economy Purchases	0.00	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0.00
5	Hedging Settlement	3,803,955.00	4,173,375.00	3,233,845.00	4,448,560.00	3,920,849.00	5,652,830.00	6,493,000	4,172,000	2,479,000	2,649,000	2,267,000	1,564,000	44,857,414.00
6	Adjustment to Fuel Cost	67,726.12	53,326.61	35,416.10	28,692.12	58,560.22	1,867.98	0	0	0	0	0	0	245,589.15
7	**Total Fuel & Net Power Trans.**	$ 42,410,120.66	$ 39,235,177.49	$ 36,645,842.53	$ 39,819,433.81	$ 48,427,227.49	$ 56,773,211.70	$ 59,814,713.00	$ 57,319,561.00	$ 50,823,857.00	$ 41,969,981.00	$ 40,196,520.00	$ 49,635,658.00	563,071,303.68
	(Sum of Lines 1 - 5)													
6	System KWH Sold	872,624,579	775,960,107	780,652,929	803,952,647	955,750,871	1,212,276,544	1,194,173,000	1,192,209,000	1,022,432,000	879,902,000	778,321,000	899,314,000	11,367,568,677
6a	Jurisdictional % of Total Sales	96.3693	96.4138	96.6259	96.8410	96.8095	96.8707	96.7819	96.7089	96.7225	96.5548	96.3865	96.4271	96.6446
7	Cost per KWH Sold (¢/KWH)	4.8601	5.0563	4.6943	4.9530	5.0669	4.6832	5.0089	4.8078	4.9709	4.7698	5.1645	5.5193	4.9533
7a	Jurisdictional Loss Multiplier	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007	1.0007
7b	Jurisdictional Cost (¢/KWH)	4.8635	5.0598	4.6976	4.9565	5.0704	4.6865	5.0124	4.8112	4.9744	4.7731	5.1681	5.5232	4.9568
8	GPIF (¢ / KWH) *	(0.0020)	(0.0023)	(0.0023)	(0.0022)	(0.0018)	(0.0015)	(0.0015)	(0.0015)	(0.0017)	(0.0020)	(0.0023)	(0.0020)	(0.0019)
9	True-Up (¢/KWH) *	0.4754	0.5344	0.5300	0.5135	0.4321	0.3404	0.3459	0.3467	0.4043	0.4706	0.5329	0.4610	0.4367
10	TOTAL	5.3369	5.5919	5.2253	5.4678	5.5007	5.0254	5.3568	5.1564	5.3770	5.2417	5.6987	5.9822	5.3916
11	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
12	Recovery Factor Adjusted for Taxes	5.3407	5.5959	5.2291	5.4717	5.5047	5.0290	5.3607	5.1601	5.3809	5.2455	5.7028	5.9865	5.3955
13	**Recovery Factor Rounded to the Nearest .001 ¢/KWH**	5.341	5.596	5.229	5.472	5.505	5.029	5.361	5.160	5.381	5.246	5.703	5.987	5.396

* ¢/KWH CALCULATIONS BASED ON JURISDICTIONAL KWH SALES

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	FUEL COST - NET GEN. ($)													
1	LIGHTER OIL (B.L.)	42,249	176,320	69,641	100,859	123,293	49,991	23,748	21,730	28,891	27,019	23,403	27,791	714,935
2	COAL excluding Scherer	24,283,058	14,477,778	20,086,017	25,992,420	34,509,080	30,027,563	46,408,399	46,215,676	45,763,487	29,709,832	32,629,454	43,819,148	393,921,911
3	COAL at Scherer	2,952,453	2,603,302	3,227,375	2,806,843	2,647,167	2,923,046	3,146,893	3,186,936	2,991,639	3,163,206	3,073,878	3,223,258	35,945,996
4	GAS - Generation	11,704,449	12,858,496	8,729,468	12,010,860	10,921,136	11,991,560	8,397,673	8,917,219	5,845,840	11,497,924	11,354,785	11,304,461	125,533,871
5	GAS (B.L.)	22,826	281,236	158,794	73,468	31,038	59,475	0	0	0	0	0	0	626,837
6	OIL - C.T.	4,141	11,645	0	14,233	0	0	0	0	0	0	0	0	30,019
7	TOTAL ($)	39,009,176	30,408,777	32,271,295	40,998,683	48,231,714	45,051,635	57,976,713	58,341,561	54,629,857	44,397,981	47,081,520	58,374,658	556,773,569
	SYSTEM NET GEN. (MWH)													
8	LIGHTER OIL (B.L.)	0	0	0	0	0	0	0	0	0	0	0	0	-
9	COAL excluding Scherer	612,763	338,211	459,531	573,073	752,909	700,669	1,052,544	1,066,539	1,000,444	664,002	702,819	891,059	8,814,564
10	COAL at Scherer	136,988	129,821	141,436	128,105	123,184	136,534	140,802	142,361	133,362	141,043	137,204	143,891	1,634,731
11	GAS	266,425	343,138	254,182	370,802	319,138	337,709	253,500	254,858	160,775	312,568	275,263	248,073	3,396,430
12	OIL - C.T.	5	40	(21)	11	(22)	(23)	0	0	0	0	0	0	(10)
13	TOTAL (MWH)	1,016,181	811,210	855,128	1,071,991	1,195,209	1,174,889	1,446,846	1,463,759	1,294,580	1,117,613	1,115,286	1,283,023	13,845,714
	UNITS OF FUEL BURNED													
14	LIGHTER OIL (BBL)	461	2,243	902	1,311	1,722	660	337	304	401	374	323	383	9,420
15	COAL excl. Scherer (TON) (1)	287,446	168,646	217,227	296,533	360,219	322,031	484,188	486,851	459,080	308,049	325,729	413,810	4,129,809
16	GAS-all (MCF) (2)	1,789,150	2,363,074	1,783,436	2,562,458	2,177,634	2,318,936	1,700,612	1,709,645	1,062,162	2,064,034	1,807,778	1,606,158	22,945,077
17	OIL - C.T. (BBL)	50	141	0	173	0	0	0	0	0	0	0	0	364
	BTU'S BURNED (MMBTU)													
18	COAL + GAS B.L. + OIL B.L.	7,764,017	4,979,208	6,559,185	7,556,805	9,385,229	8,943,721	12,501,494	12,635,166	11,886,603	8,356,241	8,722,809	10,885,145	110,175,623
19	GAS-Generation (2)	1,843,231	2,365,719	1,788,700	2,612,877	2,223,673	2,362,090	1,751,630	1,760,934	1,094,027	2,125,955	1,862,011	1,654,342	23,445,189
20	OIL - C.T.	291	818	0	999	0	0	0	0	0	0	0	0	2,108
21	TOTAL (MMBTU)	9,607,539	7,345,745	8,347,885	10,170,681	11,608,902	11,305,811	14,253,124	14,396,100	12,980,630	10,482,196	10,584,820	12,539,487	133,622,920

(1)Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and $ only.

(2) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	GENERATION MIX (% MWH)													
22	LIGHTER OIL (B.L.)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	COAL	73.78	57.70	70.28	65.41	73.30	71.26	82.48	82.59	87.58	72.03	75.32	80.66	75.47
24	GAS-Generation	26.22	42.30	29.72	34.59	26.70	28.74	17.52	17.41	12.42	27.97	24.68	19.34	24.53
25	OIL - C.T.	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	TOTAL (% MWH)	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
	FUEL COST $ / UNIT													
27	LIGHTER OIL ($/BBL)	91.65	78.61	77.21	76.93	71.60	75.74	70.54	71.40	72.01	72.33	72.50	72.61	75.89
28	COAL ($/TON) (1)	84.48	85.85	92.47	87.65	95.80	93.24	95.85	94.93	99.69	96.45	100.17	105.89	95.39
29	GAS + B.L. ($/MCF) (2)	6.44	5.48	4.89	4.65	4.92	5.08	4.69	4.97	5.11	5.34	6.02	6.71	5.32
30	OIL - C.T.	82.82	82.59	0.00	82.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.47
	FUEL COST $ / MMBTU													
31	COAL + GAS B.L. + OIL B.L.	3.52	3.52	3.59	3.83	3.98	3.70	3.97	3.91	4.10	3.94	4.10	4.32	3.91
32	GAS-Generation (2)	6.24	5.35	4.79	4.53	4.81	4.96	4.55	4.82	4.96	5.18	5.85	6.51	5.18
33	OIL - C.T.	14.23	14.24	0.00	14.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.24
34	TOTAL ($/MMBTU)	4.04	4.11	3.85	4.01	4.13	3.96	4.04	4.02	4.18	4.19	4.40	4.61	4.14
	BTU BURNED BTU / KWH													
35	COAL + GAS B.L. + OIL B.L.	10,355	10,639	10,914	10,777	10,713	10,683	10,476	10,452	10,484	10,380	10,384	10,518	10,544
36	GAS-Generation (2)	7,018	6,969	7,117	7,112	7,088	7,115	7,152	7,150	7,175	7,018	7,002	6,970	7,069
37	OIL - C.T.	58,200	20,450	0	90,818	0	0	0	0	0	0	0	0	0
38	TOTAL (BTU/KWH)	9,490	9,096	9,795	9,518	9,757	9,670	9,910	9,893	10,092	9,461	9,571	9,856	9,707
	FUEL COST CENTS / KWH													
39	COAL + GAS B.L. + OIL B.L.	3.97	4.42	4.42	4.57	4.60	4.30	4.41	4.34	4.58	4.48	4.65	4.92	4.48
40	COAL at Scherer	2.16	2.01	2.28	2.19	2.15	2.14	2.23	2.24	2.24	2.24	2.24	2.24	2.20
41	GAS-Generation	4.39	3.75	3.43	3.24	3.42	3.55	3.31	3.50	3.64	3.68	4.13	4.56	3.70
42	OIL - C.T.	82.82	29.11	0.00	129.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
43	TOTAL (¢/KWH)	3.84	3.75	3.77	3.82	4.04	3.83	4.01	3.99	4.22	3.97	4.22	4.55	4.02

(1)Excludes Plant Scherer. Coal statistics for Plant Scherer are reported in BTUs and $ only.
(2) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JANUARY 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW) 2009	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	35,017	60.3	100.0	60.3	10,550	Coal	16,459	11,223	369,427	1,455,852	4.16	88.45
2			0					Gas-G	0	1,038	0	0	0.00	0.00
3								Gas-S	1,997	1,038	2,073	14,833		7.43
4								Oil-S	48	138,964	280	4,277		89.10
5	Crist 5	78.0	17,983	31.0	93.7	33.1	10,356	Coal	8,192	11,367	186,239	724,642	4.03	88.46
6			0					Gas-G	0	1,038	0	0	0.00	0.00
7								Gas-S	1,076	1,038	1,117	7,994		7.43
8								Oil-S	43	138,964	252	3,853		89.60
9	Crist 6	302.0	(1,506)	(0.7)	0.0	0.0	0	Coal	0	11,247	0	0	0.00	0.00
10			0					Gas-G	0	1,038	0	0	0.00	0.00
11								Gas-S	0	1,038	0	0		0.00
12								Oil-S	0	138,964	0	0		0.00
13	Crist 7	472.0	224,176	63.8	96.1	66.4	10,285	Coal	102,112	11,290	2,305,686	9,032,421	4.03	88.46
14			0					Gas-G	0	1,038	0	0	0.00	0.00
15								Gas-S	0	1,038	0	0		0.00
16								Oil-S	86	138,964	503	7,686		89.37
17	Scherer 3 (2)	211.0	136,988	87.3	98.5	88.6	9,894	Coal	N/A	8,350	1,355,418	2,943,489	2.15	#NA
18								Oil-S	80	140,150	473	7,662		95.78
19	Scholz 1	46.0	(238)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20								Oil-S	(1)	140,009	(6)	(128)		0.00
21	Scholz 2	46.0	(252)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
22								Oil-S	(1)	140,009	(6)	(151)		0.00
23	Smith 1	162.0	83,280	69.1	100.0	69.1	10,413	Coal	37,820	11,465	867,212	3,532,571	4.24	93.40
24								Oil-S	61	138,225	354	5,441		89.20
25	Smith 2	195.0	77,780	53.6	99.4	54.0	10,630	Coal	36,154	11,434	826,774	3,376,981	4.34	93.41
26								Oil-S	73	138,225	425	6,532		89.48
27	Smith 3	531.0	262,662	66.5	100.0	66.5	7,018	Gas-G	1,786,077	1,032	1,843,231	11,502,874	4.38	6.44
28	Smith A (3)	40.0	5	0.0	95.8	0.0	58,200	Oil	50	137,845	291	4,141	82.82	82.82
29	Other Generation	0.0	3,763						0	0		201,575	5.36	0.00
30	Daniel 1 (1)	250.0	67,802	36.5	99.9	36.5	11,512	Coal	39,522	9,875	780,560	2,810,385	4.14	71.11
31								Oil-S	10	137,622	58	997		99.70
32	Daniel 2 (1)	253.5	108,721	57.6	99.4	58.0	9,812	Coal	47,187	11,304	1,066,804	3,355,438	3.09	71.11
33								Oil-S	65	137,622	374	6,388		98.28
34	Total	2,664.5	1,016,181	51.3	67.6	75.9	9,490				9,607,539	39,005,752	3.84	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
(3) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Railcar Track Deprec.	(5,233)	
NA	Scherer Coal Inventory Adjustment	8,964	
(3)	Scherer Oil Inventory Adjustment	(307)	
	Recoverable Fuel	39,009,176	3.84

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: FEBRUARY 2009

Line	Plant/Unit (a)	Net Cap. (MW) 2009 (b)	Net Gen. (MWH) (c)	Cap. Factor (%) (d)	Equiv. Avail. Factor (%) (e)	Net Output Factor (%) (f)	Avg. Net Heat Rate (BTU/KWH) (g)	Fuel Type (h)	Fuel Burned (Units) (Tons/MCF/Bbl) (i)	Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.) (j)	Fuel Burned (MMBTU) (k)	Fuel Burned Cost ($) (l)	Fuel Cost/ KWH (¢/KWH) (m)	Fuel Cost/ Unit ($/Unit) (n)
1	Crist 4	78.0	32,428	61.9	100.0	61.9	10,608	Coal	14,981	11,481	344,006	1,353,535	4.17	90.35
2			0					Gas-G	0	1,028	0	0	0.00	0.00
3								Gas-S	0	1,028	0	0		0.00
4								Oil-S	49	138,964	285	4,287		87.49
5	Crist 5	78.0	38,037	72.6	98.0	74.0	10,651	Coal	17,688	11,452	405,119	1,598,031	4.20	90.35
6			0					Gas-G	0	1,028	0	0	0.00	0.00
7								Gas-S	0	1,028	0	0		0.00
8								Oil-S	32	138,964	185	2,790		87.19
9	Crist 6	302.0	67,987	33.6	59.0	57.0	10,313	Coal	30,503	11,493	701,147	2,755,873	4.05	90.35
10			206					Gas-G	2,095	1,028	2,154	9,537	4.63	4.55
11								Gas-S	61,791	1,028	63,521	281,235		4.55
12								Oil-S	0	138,964	0	0		0.00
13	Crist 7	472.0	(773)	(0.2)	0.0	0.0	0	Coal	4,400	11,339	99,783	389,207	0.00	88.46
14			0					Gas-G	0	1,028	0	0	0.00	0.00
15								Gas-S	0	1,028	0	0		0.00
16								Oil-S	0	138,964	0	0		0.00
17	Scherer 3 (2)	211.0	129,821	91.6	100.0	91.6	9,270	Coal	N/A	8,440	1,203,398	2,603,301	2.01	#NA
18								Oil-S	0	140,150	4	59		0.00
19	Scholz 1	46.0	(202)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20								Oil-S	0	0	0	0		0.00
21	Scholz 2	46.0	(226)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
22								Oil-S	0	0	0	0		0.00
23	Smith 1	162.0	17,335	15.9	100.0	15.9	10,806	Coal	8,227	11,385	187,321	782,758	4.52	95.15
24								Oil-S	55	137,557	318	4,251		77.29
25	Smith 2	195.0	87,170	66.5	99.0	67.2	10,213	Coal	38,811	11,469	890,241	3,692,805	4.24	95.15
26								Oil-S	306	137,557	1,771	23,707		77.47
27	Smith 3	531.0	339,274	95.1	99.9	95.2	6,967	Gas-G	2,299,188	1,028	2,363,565	12,653,282	3.73	5.50
28	Smith A (3)	40.0	40	0.1	98.8	0.2	20,450	Oil	141	137,845	818	11,645	29.11	82.59
29	Other Generation	0.0	3,658						0	0		195,677	5.35	0.00
30	Daniel 1 (1)	252.5	29,035	17.1	99.6	17.2	11,747	Coal	17,200	9,915	341,076	1,244,833	4.29	72.37
31								Oil-S	907	138,851	5,290	71,138		78.43
32	Daniel 2 (1)	252.5	67,420	39.7	99.0	40.1	10,836	Coal	36,836	9,916	730,531	2,665,970	3.95	72.37
33								Oil-S	894	138,851	5,212	70,088		78.40
34	Total	2,666.0	811,210	45.3	57.4	78.8	9,096				7,345,745	30,414,010	3.75	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
(3) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Railcar Track Deprec.	(5,233)	
	Recoverable Fuel	30,408,777	3.75

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MARCH 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW) 2009	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	5,272	9.1	100.0	9.1	12,394	Coal	2,857	11,435	65,340	269,324	5.11	94.27
2			0					Gas-G	0	1,026	0	0	0.00	0.00
3								Gas-S	0	1,026	0	0		0.00
4								Oil-S	12	138,964	71	1,062		88.50
5	Crist 5	78.0	43,694	75.4	99.4	75.9	11,011	Coal	21,116	11,392	481,102	1,990,542	4.56	94.27
6			0					Gas-G	0	1,026	0	0	0.00	0.00
7								Gas-S	0	1,026	0	0		0.00
8								Oil-S	78	138,964	455	6,846		87.77
9	Crist 6	302.0	99,614	44.4	100.0	44.4	11,166	Coal	47,818	11,630	1,112,256	4,507,744	4.53	94.27
10			0					Gas-G	0	1,026	0	0	0.00	0.00
11								Gas-S	24,182	1,026	24,812	95,846		3.96
12								Oil-S	0	138,964	0	0		0.00
13	Crist 7	472.0	124,522	35.5	46.7	76.1	11,317	Coal	62,432	11,286	1,409,227	5,885,393	4.73	94.27
14			29					Gas-G	307	1,026	315	1,216	4.19	3.96
15								Gas-S	15,882	1,026	16,294	62,948		3.96
16								Oil-S	232	138,964	1,355	20,398		87.92
17	Scherer 3 (2)	211.0	141,436	90.2	99.6	90.6	10,580	Coal	N/A	8,375	1,496,460	3,227,375	2.28	#NA
18								Oil-S	66	140,150	389	5,317		80.56
19	Scholz 1	46.0	(231)	(0.7)	85.4	0.0	0	Coal	0	0	0	0	0.00	0.00
20								Oil-S	0	0	0	0		0.00
21	Scholz 2	46.0	(205)	(0.6)	92.4	0.0	0	Coal	0	0	0	0	0.00	0.00
22								Oil-S	0	0	0	0		0.00
23	Smith 1	162.0	32,114	26.7	100.0	26.7	10,587	Coal	14,784	11,498	339,983	1,459,478	4.54	98.72
24								Oil-S	327	137,565	1,889	22,715		69.46
25	Smith 2	195.0	106,740	73.7	100.0	73.7	10,249	Coal	47,881	11,424	1,093,981	4,726,637	4.43	98.72
26								Oil-S	151	137,565	874	10,514		69.63
27	Smith 3	531.0	251,290	63.7	70.9	89.9	7,117	Gas-G	1,743,065	1,026	1,788,385	8,567,469	3.41	4.92
28	Smith A (3)	40.0	(21)	(0.1)	100.0	0.0	0	Oil	0	137,845	0	0	0.00	0.00
29	Other Generation	0.0	2,863						0	0		160,783	5.62	0.00
30	Daniel 1 (1)	255.0	24,028	12.7	99.9	12.7	10,829	Coal	13,073	9,952	260,205	943,749	3.93	72.19
31								Oil-S	10	138,488	57	757		75.70
32	Daniel 2 (1)	255.0	23,983	12.7	100.0	12.7	10,603	Coal	13,134	9,681	254,291	948,117	3.95	72.19
33								Oil-S	25	138,488	144	1,927		77.08
34	Total	2,671.0	855,128	43.1	70.3	61.3	9,795				8,347,885	32,916,157	3.85	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
(3) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Railcar Track Deprec.	(5,233)	
11,479	Crist Flyover Adjustment	1,037,379	
(16,558)	Smith Flyover Adjustment	(1,575,439)	
(789)	Scholz Flyover Adjustment	(101,674)	
1	Scherer Inventory Adjustment - OIL	105	
	Recoverable Fuel	32,271,295	3.77

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: APRIL 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW) 2009	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	(629)	(1.1)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
2			0					Gas-G	0	1,028	0	0	0.00	0.00
3								Gas-S	0	1,028	0	0		0.00
4								Oil-S	0	138,964	0	0		0.00
5	Crist 5	78.0	25,841	48.7	88.2	55.2	10,760	Coal	12,353	11,255	278,060	1,211,688	4.69	98.09
6			1482					Gas-G	16,128	1,028	16,585	64,610	4.36	4.01
7								Gas-S	7,520	1,028	7,731	30,124		4.01
8								Oil-S	115	138,964	669	10,067		87.54
9	Crist 6	302.0	111,005	52.9	99.5	53.2	11,473	Coal	56,291	11,312	1,273,525	5,521,612	4.97	98.09
10			3,991					Gas-G	45,370	1,028	46,637	181,760	4.55	4.01
11								Gas-S	1,452	1,028	1,493	5,815		4.00
12								Oil-S	0	138,964	0	0		0.00
13	Crist 7	472.0	113,982	33.7	80.7	41.7	11,242	Coal	55,569	11,530	1,281,432	5,450,847	4.78	98.09
14			408					Gas-G	4,557	1,028	4,685	18,257	4.47	4.01
15								Gas-S	9,368	1,028	9,627	37,529		4.01
16								Oil-S	161	138,964	938	14,111		87.65
17	Scherer 3 (2)	211.0	128,105	84.3	98.3	85.8	9,899	Coal	N/A	8,361	1,268,051	2,716,784	2.12	#NA
18								Oil-S	43	140,150	255	3,193		74.26
19	Scholz 1	46.0	(268)	(0.8)	99.6	0.0	0	Coal	9	0	0	1,237	0.00	137.44
20								Oil-S	7	140,009	39	911		130.14
21	Scholz 2	46.0	3,904	11.8	99.5	11.9	13,102	Coal	2,097	12,196	51,150	270,173	6.92	128.84
22								Oil-S	13	140,009	74	1,738		133.69
23	Smith 1	162.0	(629)	(0.5)	40.0	0.0	0	Coal	0	0	0	0	0.00	0.00
24								Oil-S	0	138,406	0	0		0.00
25	Smith 2	195.0	81,998	58.4	80.2	72.8	10,354	Coal	36,832	11,525	848,968	3,710,868	4.53	100.75
26								Oil-S	133	138,406	772	9,052		68.06
27	Smith 3	479.0	361,531	104.8	100.0	104.8	7,039	Gas-G	2,478,063	1,027	2,544,971	11,569,281	3.20	4.67
28	Smith A (3)	36.0	11	0.0	99.4	0.0	90,818	Oil	173	137,845	999	14,233	129.39	82.27
29	Other Generation	0.0	3,390						0	0		176,952	5.22	0.00
30	Daniel 1 (1)	255.0	120,083	65.4	96.6	67.7	10,568	Coal	67,121	9,453	1,268,990	4,947,308	4.12	73.71
31								Oil-S	434	138,207	2,521	31,927		73.56
32	Daniel 2 (1)	255.0	117,786	64.2	96.1	66.8	10,699	Coal	66,261	9,509	1,260,152	4,883,920	4.15	73.71
33								Oil-S	406	138,207	2,357	29,860		73.55
34	Total	2,615.0	1,071,991	56.9	71.7	79.4	9,518				10,170,681	40,913,857	3.82	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
(3) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Railcar Track Deprec.	(5,233)	
NA	Scherer Coal Inventory Adjustment	90,059	
	Recoverable Fuel	40,998,683	3.82

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: MAY 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW) 2009	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	16,208	27.9	98.5	28.4	10,048	Coal	6,996	11,639	162,853	721,313	4.45	103.10
2			0					Gas-G	0	1,027	0	0	0.00	0.00
3								Gas-S	4,247	1,027	4,362	16,081		3.79
4								Oil-S	105	138,964	611	9,196		87.58
5	Crist 5	78.0	24,155	41.6	95.7	43.5	11,038	Coal	11,415	11,678	266,612	1,176,941	4.87	103.10
6			0					Gas-G	0	1,027	0	0	0.00	0.00
7								Gas-S	1,981	1,027	2,034	7,502		3.79
8								Oil-S	40	138,964	234	3,519		87.98
9	Crist 6	302.0	141,509	63.0	99.7	63.2	11,123	Coal	67,543	11,652	1,574,034	6,963,982	4.92	103.10
10			0					Gas-G	0	1,027	0	0	0.00	0.00
11								Gas-S	1,023	1,027	1,051	3,873		3.79
12								Oil-S	0	138,964	0	0		0.00
13	Crist 7	472.0	273,732	77.9	94.7	82.4	10,839	Coal	127,464	11,639	2,967,113	13,142,028	4.80	103.10
14			0					Gas-G	0	1,027	0	0	0.00	0.00
15								Gas-S	946	1,027	971	3,582		3.79
16								Oil-S	37	138,964	213	3,206		86.65
17	Scherer 3 (2)	211.0	123,184	78.5	88.8	88.4	10,140	Coal	N/A	8,498	1,249,056	2,647,167	2.15	#NA
18								Oil-S	240	140,150	1,413	17,629		73.45
19	Scholz 1	46.0	(214)	(0.6)	95.8	0.0	0	Coal	0	0	0	0	0.00	0.00
20								Oil-S	0	140,009	0	0		0.00
21	Scholz 2	46.0	2,716	7.9	100.0	7.9	13,608	Coal	1,514	12,208	36,960	195,028	7.18	128.82
22								Oil-S	3	140,009	19	328		109.33
23	Smith 1	162.0	57,273	47.5	63.5	74.9	10,609	Coal	26,133	11,626	607,637	2,704,032	4.72	103.47
24								Oil-S	515	138,660	2,996	34,484		66.96
25	Smith 2	195.0	88,662	61.1	84.6	72.3	10,168	Coal	38,903	11,587	901,531	4,025,384	4.54	103.47
26								Oil-S	348	138,660	2,029	23,350		67.10
27	Smith 3	479.0	313,704	88.0	97.5	90.3	7,088	Gas-G	2,169,437	1,025	2,223,673	10,689,131	3.41	4.93
28	Smith A (3)	32.0	(22)	(0.1)	100.0	0.0	0	Oil	0	137,845	0	0	0.00	0.00
29	Other Generation	0.0	5,434						0	0		232,005	4.27	0.00
30	Daniel 1 (1)	255.0	139,066	73.3	99.9	73.4	10,691	Coal	74,901	9,925	1,486,785	5,213,236	3.75	69.60
31								Oil-S	83	137,825	482	6,121		73.75
32	Daniel 2 (1)	255.0	9,802	5.2	10.1	51.2	11,648	Coal	5,350	10,670	114,169	372,369	3.80	69.60
33								Oil-S	357	137,825	2,064	26,225		73.46
34	Total	2,611.0	1,195,209	61.5	67.3	91.4	9,757				11,608,902	48,237,712	4.04	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
(3) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Railcar Track Deprec.	(5,233)	
(6)	Scholz Oil Inventory Adjustment	(765)	
	Recoverable Fuel	48,231,714	4.04

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
FOR THE MONTH OF: JUNE 2009

Line	(a) Plant/Unit		(b) Net Cap. (MW) 2009	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) (Tons/MCF/Bbl)	(j) Fuel Heat Value (BTU/Unit) (lbs./cf/Gal.)	(k) Fuel Burned (MMBTU)	(l) Fuel Burned Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4		78.0	(538)	(1.0)	100.0	0.0	0	Coal	317	0	0	33,969	0.00	107.16
2				0					Gas-G	0	1,026	0	0	0.00	0.00
3									Gas-S	0	1,026	0	0		0.00
4									Oil-S	0	137,420	0	0		0.00
5	Crist 5		78.0	39,932	71.1	99.0	71.8	10,848	Coal	18,467	11,729	433,192	1,980,093	4.96	107.22
6				0					Gas-G	0	1,026	0	0	0.00	0.00
7									Gas-S	7,711	1,026	7,910	31,718		4.11
8									Oil-S	73	137,420	422	6,094		83.48
9	Crist 6		302.0	39,159	18.0	98.4	18.3	11,149	Coal	18,546	11,771	436,603	1,988,562	5.08	107.22
10				0					Gas-G	0	1,026	0	0	0.00	0.00
11									Gas-S	6,432	1,026	6,600	26,461		4.11
12									Oil-S	0	137,420	0	0		0.00
13	Crist 7		472.0	239,387	70.4	94.3	74.7	11,121	Coal	113,006	11,779	2,662,201	12,117,096	5.06	107.23
14				0					Gas-G	0	1,026	0	0	0.00	0.00
15									Gas-S	315	1,026	324	1,297		4.12
16									Oil-S	59	137,420	339	4,893		82.93
17	Scherer 3	(2)	211.0	136,534	89.9	100.0	89.9	10,053	Coal	N/A	8,347	1,372,523	2,923,046	2.14	#NA
18									Oil-S	2	140,150	13	170		85.00
19	Scholz 1		46.0	(248)	(0.7)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
20									Oil-S	0	140,009	0	0		0.00
21	Scholz 2		46.0	(203)	(0.6)	100.0	0.0	0	Coal	0	0	0	0	0.00	0.00
22									Oil-S	0	140,009	0	0		0.00
23	Smith 1		162.0	45,775	39.2	96.6	40.6	10,915	Coal	20,746	12,042	499,648	2,229,828	4.87	107.48
24									Oil-S	339	138,370	1,973	25,095		74.03
25	Smith 2		195.0	77,475	55.2	99.5	55.4	10,649	Coal	34,706	11,886	825,029	3,730,260	4.81	107.48
26									Oil-S	37	138,370	212	2,698		72.92
27	Smith 3		479.0	331,978	96.3	99.9	96.4	7,115	Gas-G	2,304,478	1,025	2,362,090	11,720,209	3.53	5.09
28	Smith A	(3)	32.0	(23)	(0.1)	100.0	0.0	0	Oil	0	137,845	0	0	0.00	0.00
29	Other Generation		0.0	5,731						0	0		271,351	4.73	0.00
30	Daniel 1	(1)	255.0	125,270	68.2	93.8	72.8	10,432	Coal	64,030	10,205	1,306,863	4,400,622	3.51	68.73
31									Oil-S	143	137,825	830	10,537		73.69
32	Daniel 2	(1)	255.0	134,660	73.3	97.5	75.2	10,315	Coal	66,201	10,491	1,389,030	4,549,794	3.38	68.73
33									Oil-S	2	137,825	9	118		59.00
34	Total		2,611.0	1,174,889	62.5	79.3	78.8	9,670				11,305,811	46,053,910	3.92	

Notes & Adjust.:
(1) Represents Gulf's 50% Ownership
(2) Represents 25% Ownership; Scherer coal is reported on a BTU and $ basis only.
(3) Smith A uses lighter oil

Negative Net Generation at any unit is due to station service
Gas-G is gas used for generation; Gas-S is gas used for starter

Units		$	cents/kwh
NA	Daniel Railcar Track Deprec.	(5,233)	
5	Scholz Oil Inventory Adjustment	386	
(13,988)	Daniel Coal Inventory Adjustment	(997,428)	
	Recoverable Fuel	45,051,635	3.83

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78	48,600	83.7	95.2	88.0	10,762	Coal	22,098	11,835	523,038	2,356,844	4.85	106.65
2	4							Gas - G						
3	Crist 5	78	47,116	81.2	95.1	85.3	10,592	Coal	21,084	11,835	499,050	2,248,754	4.77	106.66
4	5							Gas - G						
5	Crist 6	302	175,239	78.0	94.2	82.8	10,720	Coal	79,366	11,835	1,878,551	8,464,883	4.83	106.66
6	6							Gas - G						
7	Crist 7	472	289,212	82.4	93.3	88.3	10,665	Coal	130,314	11,835	3,084,457	13,898,781	4.81	106.66
8	7							Gas - G						
9	Scherer 3 (2)	211	140,802	89.7	97.2	92.3	10,292	Coal	85,062	8,519	1,449,203	3,146,893	2.23	NA
10	Scholz 1	46	3,869	11.3	95.9	11.8	12,486	Coal	1,973	12,242	48,301	262,514	6.79	133.05
11	Scholz 2	46	1,290	3.8	96.1	3.9	12,948	Coal	682	12,242	16,697	90,749	7.04	133.06
12	Smith 1	162	97,021	80.5	95.6	84.2	10,312	Coal	42,225	11,847	1,000,507	4,430,739	4.57	104.93
13	Smith 2	195	109,335	75.4	95.8	78.7	10,441	Coal	48,181	11,847	1,141,616	5,055,640	4.62	104.93
14	Smith 3	479	244,920	68.7	71.0	96.8	7,152	Gas	1,700,612	1,030	1,751,630	7,969,917	3.25	4.69
15	Smith A (CT)	32	0	0.0	99.6	0.0	#N/A	Oil	0	0	0	0	#N/A	#N/A
16	Other Generation		8,580					Gas				427,756	4.99	#N/A
17	Daniel 1 (1)	255	137,124	72.3	96.9	74.6	10,327	Coal	68,506	10,336	1,416,100	4,756,247	3.47	69.43
18	Daniel 2 (1)	255	143,740	75.8	96.9	78.2	10,032	Coal	69,759	10,336	1,442,003	4,843,248	3.37	69.43
19	Gas,BL							Gas	0	0	0	0	#N/A	#N/A
20	Ltr. Oil							Oil	337	139,400	1,971	23,748	#N/A	70.54
21		2,611.0	1,446,846	74.5	90.9	81.9	9,910				14,253,124	57,976,713	4.01	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

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2009 Est/Act True-up
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SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bb	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78	45,677	78.7	95.1	82.7	10,743	Coal	20,636	11,889	490,707	2,141,373	4.69	103.77
2	4							Gas - G						
3	Crist 5	78	48,342	83.3	95.1	87.6	10,570	Coal	21,488	11,889	510,961	2,229,762	4.61	103.77
4	5							Gas - G						
5	Crist 6	302	171,069	76.1	94.2	80.8	10,695	Coal	76,942	11,889	1,829,593	7,984,077	4.67	103.77
6	6							Gas - G						
7	Crist 7	472	296,101	84.3	93.3	90.4	10,629	Coal	132,359	11,889	3,147,345	13,734,558	4.64	103.77
8	7							Gas - G						
9	Scherer 3 (2)	211	142,361	90.7	96.9	93.6	10,290	Coal	86,005	8,516	1,464,851	3,186,936	2.24	NA
10	Scholz 1	46	2,843	8.3	95.9	8.7	12,489	Coal	1,450	12,242	35,501	192,950	6.79	133.07
11	Scholz 2	46	1,481	4.3	96.1	4.5	12,957	Coal	784	12,242	19,189	104,291	7.04	133.02
12	Smith 1	162	98,222	81.5	95.6	85.2	10,305	Coal	42,621	11,874	1,012,147	4,444,871	4.53	104.29
13	Smith 2	195	114,839	79.2	95.8	82.6	10,433	Coal	50,452	11,874	1,198,098	5,261,480	4.58	104.29
14	Smith 3	479	246,278	69.1	71.4	96.8	7,150	Gas	1,709,645	1,030	1,760,934	8,489,463	3.45	4.97
15	Smith A (CT)	32	0	0.0	99.6	0.0	#N/A	Oil	0	0	0	0	#N/A	#N/A
16	Other Generation		8,580					Gas				427,756	4.99	#N/A
17	Daniel 1 (1)	255	138,917	73.2	96.9	75.6	10,319	Coal	68,667	10,438	1,433,428	4,960,565	3.57	72.24
18	Daniel 2 (1)	255	149,048	78.6	96.9	81.1	10,007	Coal	71,452	10,438	1,491,564	5,161,749	3.46	72.24
19	Gas,BL							Gas	0	0	0	0	#N/A	#N/A
20	Ltr. Oil							Oil	304	139,400	1,782	21,730	#N/A	71.40
21		2,611.0	1,463,759	75.4	91.0	82.8	9,893				14,396,100	58,341,561	3.99	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

Docket No. 090001-EI
2009 Est/Act True-up
Exhibit RWD-2, Page 15 of 31

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bb	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78	45,842	81.6	95.1	85.8	10,770	Coal	20,846	11,842	493,718	2,272,546	4.96	109.02
2	4							Gas - G						
3	Crist 5	78	45,620	81.2	95.1	85.4	10,609	Coal	20,434	11,842	483,967	2,227,662	4.88	109.02
4	5							Gas - G						
5	Crist 6	302	165,048	75.9	94.2	80.6	10,743	Coal	74,863	11,842	1,773,052	8,161,217	4.94	109.02
6	6							Gas - G						
7	Crist 7	472	281,441	82.8	93.3	88.7	10,657	Coal	126,638	11,842	2,999,301	13,805,541	4.91	109.02
8	7							Gas - G						
9	Scherer 3 (2)	211	133,362	87.8	96.9	90.6	10,302	Coal	80,686	8,514	1,373,864	2,991,639	2.24	NA
10	Scholz 1	46	2,352	7.1	95.9	7.4	12,481	Coal	1,199	12,242	29,349	159,509	6.78	133.04
11	Scholz 2	46	1,098	3.3	96.1	3.5	12,938	Coal	580	12,242	14,206	77,208	7.03	133.12
12	Smith 1	162	87,651	75.1	95.6	78.6	10,318	Coal	38,185	11,842	904,368	4,182,972	4.77	109.54
13	Smith 2	195	103,281	73.6	95.8	76.8	10,451	Coal	45,574	11,842	1,079,344	4,992,285	4.83	109.54
14	Smith 3	479	152,471	44.2	47.6	92.8	7,175	Gas	1,062,162	1,030	1,094,027	5,431,844	3.56	5.11
15	Smith A (CT)	32	0	0.0	99.6	0.0	#N/A	Oil	0	0	0	0	#N/A	#N/A
16	Other Generation		8,304					Gas				413,996	4.99	#N/A
17	Daniel 1 (1)	255	130,991	71.3	96.9	73.7	10,344	Coal	64,824	10,451	1,354,912	4,900,210	3.74	75.59
18	Daniel 2 (1)	255	137,120	74.7	96.9	77.1	10,051	Coal	65,937	10,451	1,378,173	4,984,337	3.64	75.59
19	Gas,BL							Gas	0	0	0	0	#N/A	#N/A
20	Ltr. Oil							Oil	401	139,400	2,349	28,891	#N/A	72.01
21		2,611.0	1,294,580	68.9	86.6	79.5	10,092				12,980,630	54,629,857	4.22	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78	33,017	56.9	95.1	59.8	10,743	Coal	15,006	11,819	354,710	1,672,391	5.07	111.45
2	4							Gas - G						
3	Crist 5	78	47,694	82.2	95.1	86.4	10,590	Coal	21,368	11,819	505,073	2,381,322	4.99	111.44
4	5							Gas - G						
5	Crist 6	302	102,607	45.7	56.2	81.3	10,731	Coal	46,582	11,819	1,101,053	5,191,256	5.06	111.44
6	6							Gas - G						
7	Crist 7	472	7,076	2.0	5.8	34.5	10,595	Coal	3,172	11,819	74,972	353,477	5.00	111.44
8	7							Gas - G						
9	Scherer 3 (2)	211	141,043	89.8	96.9	92.7	10,294	Coal	85,251	8,515	1,451,839	3,163,206	2.24	NA
10	Scholz 1	46	2,597	7.6	94.9	8.0	12,486	Coal	1,324	12,242	32,425	176,229	6.79	133.10
11	Scholz 2	46	0	0.0	92.1	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
12	Smith 1	162	94,500	78.4	95.5	82.1	10,289	Coal	41,200	11,800	972,305	4,806,472	5.09	116.66
13	Smith 2	195	104,379	71.9	95.5	75.4	10,418	Coal	46,077	11,800	1,087,413	5,375,495	5.15	116.66
14	Smith 3	479	302,915	85.0	79.7	106.6	7,018	Gas	2,064,034	1,030	2,125,955	11,016,699	3.64	5.34
15	Smith A (CT)	32	0	0.0	99.6	0.0	#N/A	Oil	0	0	0	0	#N/A	#N/A
16	Other Generation		9,653					Gas				481,225	4.99	#N/A
17	Daniel 1 (1)	255	132,351	69.8	95.3	73.2	10,350	Coal	65,829	10,404	1,369,841	4,815,807	3.64	73.16
18	Daniel 2 (1)	255	139,781	73.7	95.4	77.2	10,047	Coal	67,491	10,404	1,404,423	4,937,383	3.53	73.16
19	Gas,BL							Gas	0	0	0	0	#N/A	#N/A
20	Ltr. Oil							Oil	374	139,400	2,187	27,019	#N/A	72.33
21		2,611.0	1,117,613	57.5	71.9	80.0	9,461				10,482,196	44,397,981	3.97	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bb	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78	40,390	71.9	95.1	75.6	10,732	Coal	18,364	11,803	433,482	2,123,008	5.26	115.61
2	4							Gas - G						
3	Crist 5	78	43,073	76.7	85.6	89.6	10,550	Coal	19,251	11,803	454,425	2,225,576	5.17	115.61
4	5							Gas - G						
5	Crist 6	302	148,237	68.2	82.5	82.6	10,709	Coal	67,248	11,803	1,587,436	7,774,576	5.24	115.61
6	6							Gas - G						
7	Crist 7	472	0	0.0	0.0	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
8	7							Gas - G						
9	Scherer 3 (2)	211	137,204	90.3	97.0	93.1	10,293	Coal	82,740	8,534	1,412,241	3,073,878	2.24	37.15
10	Scholz 1	46	1,290	3.9	94.9	4.1	12,485	Coal	658	12,242	16,100	87,505	6.79	132.99
11	Scholz 2	46	0	0.0	25.4	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
12	Smith 1	162	98,637	84.6	95.6	88.5	10,289	Coal	43,067	11,783	1,014,921	5,364,119	5.44	124.55
13	Smith 2	195	103,611	73.8	95.5	77.3	10,419	Coal	45,807	11,783	1,079,490	5,705,381	5.51	124.55
14	Smith 3	531	265,921	69.6	74.9	92.9	7,002	Gas	1,807,778	1,030	1,862,011	10,889,040	4.09	6.02
15	Smith A (CT)	40	0	0.0	99.6	0.0	#N/A	Oil	0	0	0	0	#N/A	#N/A
16	Other Generation		9,342					Gas				465,745	4.99	#N/A
17	Daniel 1 (1)	255	129,975	70.8	95.3	74.3	10,335	Coal	64,796	10,366	1,343,351	4,612,629	3.55	71.19
18	Daniel 2 (1)	255	137,608	74.9	95.4	78.6	10,025	Coal	66,538	10,366	1,379,473	4,736,660	3.44	71.19
19	Gas,BL							Gas	0	0	0	0	#N/A	#N/A
20	Ltr. Oil							Oil	323	139,400	1,890	23,403	#N/A	72.50
21		2,671.0	1,115,286	58.0	71.7	80.9	9,571				10,584,820	47,081,520	4.22	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2009

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bb	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 4	78	39,338	67.8	82.9	81.8	11,078	Coal	18,475	11,794	435,783	2,206,362	5.61	119.42
2	4							Gas - G						
3	Crist 5	78	13,734	23.7	33.8	70.1	10,932	Coal	6,365	11,794	150,137	760,143	5.53	119.43
4	5							Gas - G						
5	Crist 6	302	175,786	78.2	91.7	85.3	11,063	Coal	82,446	11,794	1,944,736	9,846,169	5.60	119.43
6	6							Gas - G						
7	Crist 7	472	174,435	49.7	52.5	94.6	10,726	Coal	79,321	11,794	1,871,026	9,472,973	5.43	119.43
8	7							Gas - G						
9	Scherer 3 (2)	211	143,891	91.7	97.2	94.3	10,286	Coal	86,712	8,534	1,480,087	3,223,258	2.24	37.17
10	Scholz 1	46	0	0.0	94.9	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
11	Scholz 2	46	0	0.0	95.1	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
12	Smith 1	162	105,385	87.4	95.6	91.5	10,283	Coal	45,983	11,784	1,083,706	5,816,518	5.52	126.49
13	Smith 2	195	114,209	78.7	95.5	82.5	10,409	Coal	50,445	11,784	1,188,852	6,380,861	5.59	126.49
14	Smith 3	531	237,348	60.1	65.9	91.2	6,970	Gas	1,606,158	1,030	1,654,342	10,769,766	4.54	6.71
15	Smith A (CT)	40	0	0.0	99.6	0.0	#N/A	Oil	0	0	0	0	#N/A	#N/A
16	Other Generation		10,725					Gas				534,695	4.99	#N/A
17	Daniel 1 (1)	255	121,998	64.3	95.3	67.5	10,400	Coal	60,812	10,432	1,268,831	4,341,442	3.56	71.39
18	Daniel 2 (1)	255	146,175	77.0	95.4	80.8	9,986	Coal	69,963	10,432	1,459,746	4,994,680	3.42	71.39
19	Gas,BL							Gas	0	0	0	0	#N/A	#N/A
20	Ltr. Oil							Oil	383	139,400	2,241	27,791	#N/A	72.61
21		2,671.0	1,283,023	64.6	79.6	81.2	9,856				12,539,487	58,374,658	4.55	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

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SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF : JANUARY 2009 - DECEMBER 2009

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
Line	Plant/Unit	Net Cap. (MW)	Net Gen. (MWH)	Cap. Factor (%)	Equiv. Avail. Factor (%)	Net Output Factor (%)	Avg. Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units) Tons/MCF/Bbl	Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	Fuel Burned MMBTU	As Burned Fuel Cost ($)	Fuel Cost/ KWH (¢/KWH)	Fuel Cost/ Unit ($/Unit)
1	Crist 4	78.0	340,622	49.9	96.4	51.7	10,783	Coal	157,035	11,695	3,673,064	16,606,517	4.88	105.75
2	4		0					Gas - G	0	#DIV/0!	0	0		
3	Crist 5	78.0	435,221	63.7	89.5	71.2	10,693	Coal	199,221	11,680	4,653,937	20,755,156	4.77	104.18
4	5		1,482					Gas - G	16,128	514	16,585	64,610		
5	Crist 6	302.0	1,395,753	52.8	80.8	65.3	10,899	Coal	648,148	11,735	15,211,986	69,159,951	4.96	106.70
6	6		4,197					Gas - G	47,465	514	48,791	191,297		
7	Crist 7	472.0	2,023,290	48.9	62.6	78.2	10,825	Coal	936,787	11,690	21,902,543	97,282,322	4.81	103.85
8	7		437					Gas - G	4,864	0	5,000	19,473		
9	Scherer 3 (2)	211.0	1,634,731	88.4	97.3	90.9	10,141	Coal	#N/A	#N/A	16,576,991	35,846,972	2.19	#N/A
10	Scholz 1	46.0	11,548	2.9	96.1	3.0	14,000	Coal	6,613	12,224	161,676	879,944	7.62	133.06
11	Scholz 2	46.0	9,603	2.4	91.1	2.6	14,392	Coal	5,657	12,215	138,202	737,449	7.68	130.36
12	Smith 1	162.0	816,564	57.5	89.5	64.3	10,397	Coal	360,991	11,759	8,489,755	39,754,358	4.87	110.13
13	Smith 2	195.0	1,169,478	68.5	94.7	72.3	10,399	Coal	519,823	11,698	12,161,337	56,034,077	4.79	107.79
14	Smith 3	500.7	3,310,291	75.5	81.5	92.6	7,061	Gas - G	22,730,697	514	23,374,814	121,268,975	3.66	5.34
15	Smith A (CT)	35.7	(10)	(0.0)	99.3	(0.0)	(210,800)	Oil - G	364	2,896	2,108	30,019	(300.19)	82.47
16	Other Generation		80,023						0			3,989,516	4.99	#N/A
17	Daniel 1 (1)	254.4	1,296,640	58.2	97.2	59.9	10,513	Coal	669,281	10,183	13,630,942	47,947,033	3.70	71.64
18	Daniel 2 (1)	254.7	1,315,845	59.0	89.9	65.6	10,161	Coal	646,109	10,347	13,370,359	46,433,665	3.53	71.87
19	Gas,BL							Gas	145,923	514	149,920	626,836	#N/A	4.30
20	Ltr. Oil							Oil	9,424	2,913	54,910	715,517	#N/A	75.92
21		2,635.4	13,845,714	60.0	84.4	71.0	9,707				133,622,920	558,343,687	4.03	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

Inventory Adjustments		$	units
COAL	Crist	$1,037,379	11,479
	Scherer	99,023	-
	Scholz	(101,674)	(789)
	Smith	(1,575,439)	(16,558)
	Daniel	(997,428)	(13,988)
OIL	Crist	0	-
	Scherer	(202)	(2)
	Scholz	(379)	(1)
	Smith	0	-
	Daniel Railcar	(31,398)	
	Total Adjustments	$ (1,570,118)	(19,858)
Total Fuel Burned Cost		**$ 556,773,569**	

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SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	1,084	2,799	810	1,207	1,202	2,001	4,669	816	1,009	934	981	931	18,443
3	UNIT COST ($/BBL)	62.34	57.72	61.10	59.86	67.20	77.44	71.29	72.01	71.94	71.98	71.71	71.96	68.07
4	AMOUNT ($)	67,581	161,569	49,491	72,251	80,777	154,957	332,841	58,762	72,589	67,226	70,351	66,995	1,255,390
5	*BURNED :*													
6	UNITS (BBL)	594	2,336	1,025	1,452	1,814	763	337	304	401	374	323	383	10,106
7	UNIT COST ($/BBL)	94.37	78.82	77.22	76.59	71.66	75.64	70.47	71.48	72.05	72.24	72.46	72.56	76.28
8	AMOUNT ($)	56,055	184,121	79,155	111,207	130,000	57,717	23,748	21,730	28,891	27,019	23,403	27,791	770,837
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	6,182	6,645	6,431	6,186	5,573	6,811	11,143	11,655	12,263	12,823	13,481	14,029	
11	UNIT COST ($/BBL)	95.05	85.03	83.25	80.25	80.25	79.94	76.60	76.41	76.19	75.99	75.77	75.60	
12	AMOUNT ($)	587,602	565,050	535,386	496,430	447,207	544,447	853,540	890,572	934,270	974,477	1,021,425	1,060,629	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
14	*PURCHASES :*													
15	UNITS (TONS)	338,718	205,784	260,351	246,907	398,794	446,656	357,000	435,500	451,000	271,000	288,000	400,722	4,100,432
16	UNIT COST ($/TON)	83.31	95.06	95.70	97.21	94.37	99.64	97.16	91.95	104.66	99.81	106.16	105.47	97.71
17	AMOUNT ($)	28,218,614	19,562,851	24,916,491	24,000,683	37,634,029	44,502,635	34,684,955	40,044,822	47,203,459	27,048,072	30,575,004	42,264,238	400,655,853
18	*BURNED :*													
19	UNITS (TONS)	287,446	168,646	217,227	296,533	360,219	322,031	484,188	486,851	459,080	308,049	325,729	413,810	4,129,809
20	UNIT COST ($/TON)	84.50	85.88	92.49	87.67	95.81	93.26	95.85	94.93	99.69	96.45	100.17	105.89	95.39
21	AMOUNT ($)	24,288,291	14,483,012	20,091,250	25,997,653	34,514,313	30,032,796	46,408,399	46,215,676	45,763,487	29,709,832	32,629,454	43,819,148	393,953,311
22	*ENDING INVENTORY :*													
23	UNITS (TONS)	737,455	774,593	817,717	768,091	806,666	931,291	804,103	752,752	744,672	707,623	669,894	656,806	
24	UNIT COST ($/TON)	85.60	88.05	89.31	92.48	91.92	95.16	95.63	93.96	96.91	98.22	100.69	100.33	
25	AMOUNT ($)	63,124,063	68,203,901	73,029,142	71,032,172	74,151,888	88,621,726	76,898,282	70,727,428	72,167,400	69,505,640	67,451,190	65,896,280	
26	DAYS SUPPLY:	35	37	39	37	39	45	39	37	36	35	33	32	

SCHEDULE E-5
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SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

		JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	JULY ESTIMATED	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL
	COAL AT PLANT SCHERER													
27	*PURCHASES :*													
28	UNITS (MMBTU)	1,134,821	1,162,579	1,311,563	1,275,459	1,215,863	1,093,705	1,250,516	1,241,714	1,257,090	1,284,878	1,565,165	1,358,024	15,151,377
29	UNIT COST ($/MMBTU)	2.16	2.13	2.13	2.11	2.07	2.14	2.08	2.08	2.09	2.09	2.09	2.09	2.10
30	AMOUNT ($)	2,452,969	2,480,129	2,798,923	2,688,163	2,512,492	2,336,179	2,607,024	2,588,937	2,622,712	2,681,276	3,277,195	2,835,164	31,881,163
31	*BURNED :*													
32	UNITS (MMBTU)	1,359,543	1,203,399	1,496,460	1,309,834	1,249,056	1,372,523	1,449,203	1,464,851	1,373,864	1,451,839	1,412,241	1,480,087	16,622,900
33	UNIT COST ($/MMBTU)	2.17	2.16	2.16	2.14	2.12	2.13	2.17	2.18	2.18	2.18	2.18	2.18	2.16
34	AMOUNT ($)	2,952,453	2,603,302	3,227,375	2,806,843	2,647,167	2,923,046	3,146,893	3,186,936	2,991,639	3,163,206	3,073,878	3,223,258	35,945,996
35	*ENDING INVENTORY :*													
36	UNITS (MMBTU)	4,231,924	4,191,105	4,006,207	3,971,832	3,938,639	3,659,821	3,461,134	3,237,997	3,121,223	2,954,262	3,107,186	2,985,123	
37	UNIT COST ($/MMBTU)	2.17	2.16	2.16	2.14	2.13	2.13	2.10	2.06	2.01	1.97	1.93	1.88	
38	AMOUNT ($)	9,186,553	9,063,381	8,634,929	8,516,249	8,381,574	7,794,707	7,254,838	6,656,839	6,287,912	5,805,982	6,009,299	5,621,205	
39	DAYS SUPPLY:	82	81	77	77	76	71	67	62	60	57	60	57	
	GAS (1)													
40	*BURNED :*													
41	UNITS (MMBTU)	1,846,421	2,429,240	1,829,806	2,631,729	2,232,091	2,376,924	1,751,630	1,760,934	1,094,027	2,125,955	1,862,011	1,654,342	23,595,110
42	UNIT COST ($/MMBTU)	6.24	5.33	4.77	4.52	4.80	4.96	4.55	4.82	4.96	5.18	5.85	6.51	5.18
43	AMOUNT ($)	11,525,700	12,944,055	8,727,479	11,907,376	10,720,168	11,779,684	7,969,917	8,489,463	5,431,844	11,016,699	10,889,040	10,769,766	122,171,191
	OTHER - C.T. OIL													
44	*PURCHASES :*													
45	UNITS (BBL)	537	0	0	0	0	24,693	1,863	0	0	0	0	0	27,093
46	UNIT COST ($/BBL)	63.67	0.00	0.00	0.00	0.00	61.79	72.72	0.00	0.00	0.00	0.00	0.00	62.58
47	AMOUNT ($)	34,193	0	0	0	0	1,525,812	135,480	0	0	0	0	0	1,695,485
48	*BURNED :*													
49	UNITS (BBL)	50	141	0	173	0	0	0	0	0	0	0	0	364
50	UNIT COST ($/BBL)	82.82	82.59	0.00	82.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.47
51	AMOUNT ($)	4,141	11,645	0	14,233	0	0	0	0	0	0	0	0	30,019
52	*ENDING INVENTORY :*													
53	UNITS (BBL)	5,594	5,453	5,453	5,280	5,280	29,973	31,836	31,836	31,836	31,836	31,836	31,836	
54	UNIT COST ($/BBL)	82.46	82.46	82.46	82.47	82.47	65.43	65.86	65.86	65.86	65.86	65.86	65.86	
55	AMOUNT ($)	461,303	449,658	449,658	435,425	435,425	1,961,237	2,096,717	2,096,717	2,096,717	2,096,717	2,096,717	2,096,717	
56	DAYS SUPPLY:	3	3	3	3	3	17	1	1	1	1	1	1	

(1) Data excludes Gulf's CT in Santa Rosa County because MCF and MMBTU's are not available due to contract specifications.

SCHEDULE E-6
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POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
LINE / MONTH	TYPE & SCHEDULE	TOTAL KWH SOLD	KWH WHEELED FROM OTHER SYSTEMS	KWH FROM OWN GENERATION	(A) ¢ / KWH FUEL COST	(B) ¢ / KWH TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $
JANUARY								
1	Other Power Sales	124,027,977	67,026,433	57,001,544	1.74	2.04	2,154,698	2,528,275
2	Unit Power Sales	116,948,773	0	116,948,773	2.40	2.59	2,803,867	3,024,569
3	Economy Sales	6,272,641	0	6,272,641	5.80	5.03	363,653	315,623
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	61,300	61,300
5	TOTAL ACTUAL SALES	247,249,391	67,026,433	180,222,958	2.18	2.40	5,383,518	5,929,767
FEBRUARY								
1	Other Power Sales	93,232,261	69,843,806	23,388,455	0.85	0.98	790,289	912,085
2	Unit Power Sales	115,717,145	0	115,717,145	2.24	2.42	2,590,781	2,799,587
3	Economy Sales	1,997,019	0	1,997,019	7.17	3.83	143,091	76,394
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	24,201	24,201
5	TOTAL ACTUAL SALES	210,946,425	69,843,806	141,102,619	1.68	1.81	3,548,362	3,812,267
MARCH								
1	Other Power Sales	102,459,879	68,209,233	34,250,646	1.12	1.24	1,146,612	1,275,484
2	Unit Power Sales	95,051,799	0	95,051,799	2.04	2.23	1,937,625	2,116,362
3	Economy Sales	4,882,476	0	4,882,476	3.85	4.07	188,030	198,919
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	44,233	44,233
5	TOTAL ACTUAL SALES	202,394,154	68,209,233	134,184,921	1.64	1.80	3,316,500	3,634,998
APRIL								
1	Other Power Sales	211,820,770	59,142,734	152,678,036	2.25	2.46	4,761,774	5,208,849
2	Unit Power Sales	121,830,713	0	121,830,713	2.07	2.26	2,523,570	2,748,532
3	Economy Sales	3,775,558	0	3,775,558	3.35	3.98	126,638	150,273
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	23,321	23,321
5	TOTAL ACTUAL SALES	337,427,041	59,142,734	278,284,307	2.20	2.41	7,435,303	8,130,975
MAY								
1	Other Power Sales	190,923,895	75,300,470	115,623,425	1.93	2.11	3,690,894	4,030,447
2	Unit Power Sales	72,707,305	0	72,707,305	2.81	3.00	2,045,883	2,179,645
3	Economy Sales	5,357,682	0	5,357,682	3.43	4.01	184,006	214,749
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	24,507	24,507
5	TOTAL ACTUAL SALES	268,988,882	75,300,470	193,688,412	2.21	2.40	5,945,290	6,449,348
JUNE								
1	Other Power Sales	150,203,889	107,472,402	42,731,487	0.50	0.54	751,530	806,662
2	Unit Power Sales	113,846,437	0	113,846,437	2.21	2.39	2,519,003	2,725,150
3	Economy Sales	4,626,115	0	4,626,115	6.20	5.45	286,964	252,031
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	13,495	13,495
5	TOTAL ACTUAL SALES	268,676,441	107,472,402	161,204,039	1.33	1.41	3,570,992	3,797,338

POWER SOLD
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

(1) LINE	MONTH (2) TYPE & SCHEDULE	(3) TOTAL KWH SOLD	(4) KWH WHEELED FROM OTHER SYSTEMS	(5) KWH FROM OWN GENERATION	(6)(A) ¢ / KWH FUEL COST	(6)(B) ¢ / KWH TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT	(8) TOTAL COST $
	JULY							
1	Other Power Sales	166,101,000	0	166,101,000	4.30	4.58	7,138,000	7,615,000
2	Unit Power Sales	141,681,000	0	141,681,000	2.24	2.42	3,168,000	3,423,000
3	Economy Sales	4,636,000	0	4,636,000	4.25	4.49	197,000	208,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	70,000	70,000
5	TOTAL ESTIMATED SALES	312,418,000	0	312,418,000	3.38	3.62	10,573,000	11,316,000
	AUGUST							
1	Other Power Sales	164,901,000	0	164,901,000	4.26	4.58	7,028,000	7,548,000
2	Unit Power Sales	143,428,000	0	143,428,000	2.24	2.42	3,209,000	3,465,000
3	Economy Sales	6,150,000	0	6,150,000	4.29	4.55	264,000	280,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	93,000	93,000
5	TOTAL ESTIMATED SALES	314,479,000	0	314,479,000	3.37	3.62	10,594,000	11,386,000
	SEPTEMBER							
1	Other Power Sales	180,622,000	0	180,622,000	4.14	4.45	7,481,000	8,046,000
2	Unit Power Sales	132,715,000	0	132,715,000	2.23	2.41	2,966,000	3,202,000
3	Economy Sales	4,566,000	0	4,566,000	4.10	4.40	187,000	201,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	69,000	69,000
5	TOTAL ESTIMATED SALES	317,903,000	0	317,903,000	3.37	3.62	10,703,000	11,518,000
	OCTOBER							
1	Other Power Sales	141,727,000	0	141,727,000	3.77	4.04	5,344,000	5,721,000
2	Unit Power Sales	140,057,000	0	140,057,000	2.24	2.41	3,132,000	3,382,000
3	Economy Sales	7,210,000	0	7,210,000	3.84	4.12	277,000	297,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	109,000	109,000
5	TOTAL ESTIMATED SALES	288,994,000	0	288,994,000	3.07	3.29	8,862,000	9,509,000
	NOVEMBER							
1	Other Power Sales	186,896,000	0	186,896,000	3.76	4.05	7,021,000	7,568,000
2	Unit Power Sales	151,739,000	0	151,739,000	2.35	2.54	3,569,000	3,848,000
3	Economy Sales	8,474,000	0	8,474,000	3.84	4.09	325,000	347,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	128,000	128,000
5	TOTAL ESTIMATED SALES	347,109,000	0	347,109,000	3.18	3.43	11,043,000	11,891,000
	DECEMBER							
1	Other Power Sales	196,680,000	0	196,680,000	3.83	4.10	7,529,000	8,067,000
2	Unit Power Sales	169,751,000	0	169,751,000	2.44	2.63	4,149,000	4,462,000
3	Economy Sales	9,233,000	0	9,233,000	3.95	4.16	365,000	384,000
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	139,000	139,000
5	TOTAL ESTIMATED SALES	375,664,000	0	375,664,000	3.24	3.47	12,182,000	13,052,000
	TOTAL							
1	Other Power Sales	1,909,595,671	446,995,078	1,462,600,593	2.87	3.11	54,836,797	59,326,802
2	Unit Power Sales	1,515,473,172	0	1,515,473,172	2.28	2.47	34,613,729	37,375,845
3	Economy Sales	67,180,491	0	67,180,491	4.33	4.35	2,907,382	2,924,989
4	Gain on Economy Sales	0	0	0	#N/A	#N/A	799,057	799,057
5	TOTAL ESTIMATED SALES	3,492,249,334	446,995,078	3,045,254,256	2.67	2.88	93,156,965	100,426,693

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH.	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
		TYPE	TOTAL	FOR	KWH	KWH	(A)	(B)	TOTAL $
	PURCHASED	AND	KWH	OTHER	FOR	FOR	FUEL	TOTAL	FOR
MONTH	FROM:	SCHEDULE	PURCHASED	UTILITIES	INTERRUPTIBLE	FIRM	COST	COST	FUEL ADJ.
JANUARY	Solutia	COG-1	3,628,000	0	0	0	4.31	4.31	156,340
	Other	COG-1	4,273,000	0	0	0	7.36	7.36	314,610
	Total		7,901,000	0	0	0	5.96	5.96	470,950
FEBRUARY	Solutia	COG-1	4,199,000	0	0	0	4.67	4.67	196,031
	Other	COG-1	4,489,000	0	0	0	7.32	7.32	328,544
	Total		8,688,000	0	0	0	6.04	6.04	524,575
MARCH	Solutia	COG-1	6,993,000	0	0	0	3.61	3.61	252,600
	Other	COG-1	4,894,000	0	0	0	7.19	7.19	351,989
	Total		11,887,000	0	0	0	5.09	5.09	604,589
APRIL	Solutia	COG-1	1,118,000	0	0	0	3.11	3.11	34,764
	Other	COG-1	3,494,000	0	0	0	7.34	7.34	256,552
	Total		4,612,000	0	0	0	6.32	6.32	291,316
MAY	Solutia	COG-1	265,000	0	0	0	4.35	4.35	11,538
	Other	COG-1	137,000	0	0	0	3.27	3.27	4,479
	Total		402,000	0	0	0	3.98	3.98	16,017
JUNE	Solutia	COG-1	2,503,000	0	0	0	3.87	3.87	96,773
	Other	COG-1	3,726,000	0	0	0	7.12	7.12	265,323
	Total		6,229,000	0	0	0	5.81	5.81	362,096
JULY	Solutia	COG-1	0	0	0	0	0.00	0.00	0
	Other	COG-1	0	0	0	0	0.00	0.00	0
	Total		0	0	0	0	0.00	0.00	0
AUGUST	Solutia	COG-1	0	0	0	0	0.00	0.00	0
	Other	COG-1	0	0	0	0	0.00	0.00	0
	Total		0	0	0	0	0.00	0.00	0
SEPTEMBER	Solutia	COG-1	0	0	0	0	0.00	0.00	0
	Other	COG-1	0	0	0	0	0.00	0.00	0
	Total		0	0	0	0	0.00	0.00	0
OCTOBER	Solutia	COG-1	0	0	0	0	0.00	0.00	0
	Other	COG-1	0	0	0	0	0.00	0.00	0
	Total		0	0	0	0	0.00	0.00	0
NOVEMBER	Solutia	COG-1	0	0	0	0	0.00	0.00	0
	Other	COG-1	0	0	0	0	0.00	0.00	0
	Total		0	0	0	0	0.00	0.00	0
DECEMBER	Solutia	COG-1	0	0	0	0	0.00	0.00	0
	Other	COG-1	0	0	0	0	0.00	0.00	0
	Total		0	0	0	0	0.00	0.00	0
TOTAL			39,719,000	0	0	0	5.71	5.71	2,269,543

SCHEDULE E-9
Page 1 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

(1)		(2)	(3)	(4)	(5)
LINE	MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JANUARY				
1		Southern Co. Interchange	85,186,813	4.59	3,913,367
2		Other Purchases	74,479,070	0.71	528,465
3		ACTUAL TOTAL PURCHASES	159,665,883	2.78	4,441,832
	FEBRUARY				
1		Southern Co. Interchange	119,094,356	5.54	6,596,378
2		Other Purchases	93,910,617	1.09	1,027,106
3		ACTUAL TOTAL PURCHASES	213,004,973	3.58	7,623,484
	MARCH				
1		Southern Co. Interchange	79,840,524	3.79	3,027,811
2		Other Purchases	88,769,102	0.89	789,387
3		ACTUAL TOTAL PURCHASES	168,609,626	2.26	3,817,198
	APRIL				
1		Southern Co. Interchange	26,434,418	4.02	1,062,793
2		Other Purchases	66,254,995	0.64	424,692
3		ACTUAL TOTAL PURCHASES	92,689,413	1.60	1,487,485
	MAY				
1		Southern Co. Interchange	41,858,583	4.01	1,677,564
2		Other Purchases	79,076,395	0.59	467,814
3		ACTUAL TOTAL PURCHASES	120,934,978	1.77	2,145,378
	JUNE				
1		Southern Co. Interchange	146,336,412	4.09	5,978,683
2		Other Purchases	186,270,017	1.77	3,297,092
3		ACTUAL TOTAL PURCHASES	332,606,429	2.79	9,275,775

SCHEDULE E-9
Page 2 of 2

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ACTUAL FOR THE PERIOD JANUARY 2009 - JUNE 2009 / ESTIMATED FOR JULY 2009 - DECEMBER 2009

(1)	(2)	(3)	(4)	(5)
LINE / MONTH	TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
JULY				
1	Southern Co. Interchange	59,084,000	3.67	2,166,000
2	Other Purchases	95,574,000	3.93	3,752,000
3	TOTAL ESTIMATED PURCHASES	154,658,000	3.83	5,918,000
AUGUST				
1	Southern Co. Interchange	54,081,000	3.79	2,048,000
2	Other Purchases	83,303,000	4.02	3,352,000
3	TOTAL ESTIMATED PURCHASES	137,384,000	3.93	5,400,000
SEPTEMBER				
1	Southern Co. Interchange	48,182,000	3.85	1,854,000
2	Other Purchases	65,328,000	3.92	2,564,000
3	TOTAL ESTIMATED PURCHASES	113,510,000	3.89	4,418,000
OCTOBER				
1	Southern Co. Interchange	55,806,000	3.69	2,062,000
2	Other Purchases	45,000,000	3.83	1,723,000
3	TOTAL ESTIMATED PURCHASES	100,806,000	3.75	3,785,000
NOVEMBER				
1	Southern Co. Interchange	28,124,000	3.63	1,020,000
2	Other Purchases	20,748,000	4.20	871,000
3	TOTAL ESTIMATED PURCHASES	48,872,000	3.87	1,891,000
DECEMBER				
1	Southern Co. Interchange	33,397,000	3.93	1,311,000
2	Other Purchases	12,559,000	4.52	568,000
3	TOTAL ESTIMATED PURCHASES	45,956,000	4.09	1,879,000
TOTAL FOR PERIOD				
1	Southern Co. Interchange	777,425,106	4.21	32,717,596
2	Other Purchases	911,272,196	2.13	19,364,556
3	TOTAL ACT/EST PURCHASES	1,688,697,302	3.08	52,082,152

SCHEDULE CCE-1A

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
TO BE INCLUDED IN THE PERIOD JANUARY 2010 - DECEMBER 2010

1	Estimated over/(under)-recovery, January 2009 - December 2009 (Schedule CCE-1B, Line 15)	($1,787,568)
2	Final True-Up, January 2008 - December 2008 (Exhibit No.____(RWD-1), filed March 9, 2009	680,158
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2010 - December 2010)	($1,107,410)
4	Jurisdictional KWH sales, January 2010 - December 2010	11,240,618,000
5	True-up Factor (Line 3 / Line 4) x 100 (¢/KWH)	0.0099

PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED TRUE-UP AMOUNT
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2009 - DECEMBER 2009

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	1,095,062	474,898	259,161	317,225	472,847	570,280	3,258,284	2,606,444	1,624,791	162,180	68,953	84,784	10,994,909
2	Other Capacity Payments / (Receipts) ($)	0	0	0	0	0	5,322,362	5,302,400	5,302,400	5,302,400	591,400	590,400	590,400	23,001,762
3	Transmission Revenue ($)	(10,415)	(6,221)	(9,155)	(4,967)	(6,128)	(24,621)	(6,000)	(9,000)	(6,000)	(10,000)	(12,000)	(13,000)	(117,507)
4	Total Capacity Payments/(Receipts) ($)	1,084,647	468,677	250,006	312,258	466,719	5,868,021	8,554,684	7,899,844	6,921,191	743,580	647,353	662,184	33,879,164
5	Jurisdictional %	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160
6	Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	1,045,834	451,906	241,060	301,084	450,018	5,658,040	8,248,563	7,617,156	6,673,523	716,972	624,188	638,488	32,666,832
7	Retail KWH Sales							1,155,743,000	1,152,972,000	988,922,000	849,588,000	750,196,000	867,182,000	
8	Purchased Power Capacity Cost Recovery Factor (¢/KWH)							0.285	0.285	0.285	0.285	0.285	0.285	
9	Capacity Cost Recovery Revenues (Line 7 x Line 8/100) ($)	2,396,712	2,152,753	2,118,140	2,153,281	2,602,977	3,407,823	3,293,868	3,285,970	2,818,428	2,421,326	2,138,059	2,471,469	31,260,806
10	Revenue Taxes (Line 9 x .00072) ($)	1,726	1,550	1,525	1,550	1,874	2,454	2,372	2,366	2,029	1,743	1,539	1,779	22,508
11	True-Up Provision ($)	(30,616)	(30,616)	(30,616)	(30,616)	(30,616)	(30,616)	(30,616)	(30,616)	(30,616)	(30,616)	(30,616)	(30,612)	(367,388)
12	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 9 - Line 10 + Line 11) ($)	2,364,370	2,120,587	2,085,999	2,121,115	2,570,487	3,374,753	3,260,880	3,252,988	2,785,783	2,388,967	2,105,904	2,439,078	30,870,910
13	Over/(Under) Recovery (Line 12 - Line 6) ($)	1,318,536	1,668,681	1,844,939	1,820,031	2,120,469	(2,283,287)	(4,987,683)	(4,364,168)	(3,887,740)	1,671,995	1,481,715	1,800,589	(1,795,922)
14	Interest Provision ($)	547	1,613	2,331	2,442	2,386	2,201	1,319	(37)	(1,232)	(1,547)	(1,078)	(591)	8,354
15	Total Estimated True-Up for the Period January 2009 - December 2009 (Line 13 + Line 14) ($)													(1,787,568)
NOTE:	Interest is Calculated for July through December at June 2009 monthly rate of		0.0292%											
16	Beginning Balance True-Up & Interest Provision ($)	312,771	1,662,470	3,363,380	5,241,266	7,094,355	9,247,826	6,997,356	2,041,608	(2,291,981)	(6,150,337)	(4,449,273)	(2,938,020)	312,771
17	True-Up Collected/(Refunded) ($)	30,616	30,616	30,616	30,616	30,616	30,616	30,616	30,616	30,616	30,616	30,616	30,612	367,388
18	Adjustment ($)	0	0	0	0	0	0	0	0	0	0	0	0	0
19	End of Period TOTAL Net True-Up (Lines 13 + 14 + 16 + 17 + 18) ($)	1,662,470	3,363,380	5,241,266	7,094,355	9,247,826	6,997,356	2,041,608	(2,291,981)	(6,150,337)	(4,449,273)	(2,938,020)	(1,107,410)	(1,107,410)

A B C D E F G H I J K L M N O P Q R S T U V W X Y Z AA BB CC

GULF POWER COMPANY
2009 CAPACITY CONTRACTS

Schedule CCE-4
Page 1 of 1

Contract/Counterparty	Term Start	Term End	Contract Type
Southern Intercompany Interchange	2/18/2000	5 Yr Notice	SES Opco
Confidential Contracts (Aggregate)	Varies	Varies	Other
JP Morgan Ventures Energy	9/2/2008	-	Other
Calpine Power Services	Varies	5/31/2009	Other
Effingham County Power, LLC	6/11/2007	5/31/2009	Other
Exelon Power Team	1/1/2000	5/31/2009	Other
FP&L Energy Power Marketing	6/1/2003	-	Other
KGEN, LLC	5/1/2005	2/28/2009	Other
MPC Generating, LLC	6/11/2007	5/31/2009	Other
Shell Energy N.A. (U.S.)	6/1/2008	4/30/2009	Other
West Georgia Generating Company	5/11/2000	5/31/2009	Other

Capacity Costs

2009	January		February		March		April		May		June [2]		Projected July		August		September		October		November		December		
Contract	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	MW	$	Total $
Southern Intercompany Interchange	450.3	1,099,026	493.1	478,864	261.6	265,567	672.9	322,492	487.1	479,435	130.9	576,905	271.5	3,256,284	210.1	2,606,444	253.0	1,824,791	423.3	162,160	154.4	68,953	207.9	64,784	11,029,747
Coral Power,LLC	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	[redacted]														9,993,640
Southern Power Company	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	[redacted]														13,029,721
Alabama Electric Cooperative	0.0	0	0.0	0	0.0	0	[redacted]						0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(9,438)
South Carolina Electric & Gas	0.0	0	0.0	0	[redacted]		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	(2,611)
South Carolina PSA	[redacted]																								(41,167)
JP Morgan Ventures Energy [1]	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	(600)
Calpine Power Services [1]	0.0	(102)	0.0	(102)	0.0	(103)	0.0	(102)	0.0	(102)	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(511)
Effingham County Power, LLC [1]	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(51)	0.0	(51)	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(252)
Exelon Power Team [1]	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(250)
FP&L Energy Power Marketing [1]	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	(600)
KGEN, LLC [1]	0.0	(153)	0.0	(153)	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	(306)
MPC Generating, LLC [1]	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(51)	0.0	(51)	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(252)
Shell Energy N.A. (U.S.), LP [1]	0.0	(50)	0.0	(50)	0.0	(50)	0.0	(50)	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(200)
West Georgia Generating Company [1]	0.0	(50)	0.0	(50)	0.0	(51)	0.0	(50)	0.0	(50)	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	(251)
Total		1,095,062		474,896		259,161		317,225		472,847		5,892,641		9,560,684		7,908,844		6,927,191		753,560		659,353		675,184	33,996,670

(1) Generator Balancing Service provides no capacity scheduling entitlements.
(2) PPAs for peaking capacity begin.

CONFIDENTIAL

GULF POWER COMPANY

Risk Management Plan
For
Fuel Procurement
Docket No. 090001-EI

Date of Filing: August 4, 2008

GULF POWER

A SOUTHERN COMPANY

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GULF POWER LONG-TERM COAL PROCUREMENT STRATEGY AND TACTICAL PLAN AUGUST 2009

Introduction

Gulf Power (Gulf) reliably serves more than 425,000 customers. In 2008, Gulf generated 14.8 billion kilowatt hours (KWH) with $629 million in fuel expense. Coal represented 84 percent of Gulf's generation sources.

Gulf owns and operates three coal-fired plants (Crist, Smith and Scholz) with a combined normal full load gross rating of 1,379 megawatts (MW). Gulf also co-owns 50 percent of Plant Daniel, which is operated by Mississippi Power (MPC) and has a projected annual coal consumption of 1.5 million tons; and 25 percent of Plant Scherer's Unit 3, which is operated by Georgia Power (GPC) and has a projected annual consumption of 800,000 tons. The combined normal full load capacity of Gulf's ownership of Daniel and Scherer is 756 MWs.

In total, Gulf operates coal-fired plants with an annual coal consumption of more than 4 million tons. The procurement of this coal is critical to the success of Gulf Power.

Competition in the electric utility industry, consolidation in the coal industry, and environmental laws and regulations are just a few of the challenges facing power generators today. As the electric utility industry evolves, a procurement strategy must address several issues in order to provide a reliable, cost-competitive, environmentally acceptable fuel supply.

The following is:

- A review of the current coal program including current commitments and uncommitted requirements
- A procurement strategy that identifies and addresses specific risks and risk mitigation strategies and discusses a strategic plan
- A tactical plan detailing specific actions required to achieve the strategy

Fuel Program Overview

Crist and Smith are barge served plants and have seven long-term coal contracts in place effective January 1, 2010:

- Interocean Coal Sales, LDC's (old contract) La Loma mine in Colombia for 300,000 tons in 2010. This contract was originally due to expire in 2009 but the parties agreed to defer 300,000 tons under this contract from 2009 into 2010. This contract will now expire on March 31, 2010.
- Interocean Coal Sales, LDC's (new contract) La Loma mine in Colombia for approximately 1.3 million tons in 2010. The parties also

- agreed to defer 300,000 tons under this contract from 2009 into 2010.This contract expires December 31, 2010.
- The American Coal Company's Galatia mine in the Illinois Basin coal supply region. Due to a force majeure event at this mine that began in August 2007 and ended in February 2009, Gulf has elected to extend the term of this agreement to December 31, 2011 in order to receive all volume originally scheduled under this contract. Gulf is scheduled to receive approximately 1 million tons from Galatia in 2010 and 300,000 tons in 2011.
- Oxbow Mining, LLC's Elk Creek mine in Colorado for 565,000 tons in 2010 and 485,000 tons in 2011. Oxbow has had severe quality issues at this mine in 2009. The parties have agreed to defer 2009 tons into 2010 and extend the term in order to receive all coal originally scheduled under this contract. This contact will now expire on December 31, 2011.
- Consolidation Coal Company's Emery Mine in Utah for 480,000 tons in 2010. This contract expires December 31, 2010.
- Patriot Coal Sales, LLC's Fanco, Toms Fork and Beth mines in the Central Appalachian region for 466,000 tons in 2010. This contract expires December 31, 2010.
- The American Coal Company's West Ridge mine in Utah for 200,000 tons in 2010 and 188,000 tons in 2011. This coal was purchased to supplement the volume lost due to the force majeure event at American's Galatia mine mentioned above. This contract expires December 31, 2011.

Crist and Smith have no uncommitted need in 2010 and a need of almost 3 million tons in 2011. Because Crist and Smith share a common transportation mode as well as common coal contracts, these plants will be grouped together in formulating a procurement strategy.

In the following charts, the projected requirements for year 2010 through 2015 are from the August Gulf true-up file. The chart below illustrates the projected burn and commitments of coal for Crist and Smith through 2015.

[redacted]

Plant Scholz is scheduled to be retired in December 2011. Scholz is rail served and has no coal commitments in place for 2010 or 2011. Any uncommitted need will be satisfied with existing coal inventory on the ground at the plant.

The following chart illustrates the projected burn and commitments of coal for Scholz through 2011.

[redacted]

Gulf owns 50 percent of Units 1 and 2 at Daniel which is rail served and will have three long-term coal contracts in place by January 1, 2010. In addition to the three long-term contracts that will supply coal to Daniel only, Daniel will receive a portion of the import tons under another MPC contract with Interocean that expires December 31, 2011. The tonnage that is anticipated to ship to Daniel under this contract is 675,000 tons in 2010 and 375,000 tons in 2011. Daniel is classified as a New Source Performance Standard (NSPS) plant requiring the use of 1.2 lbs SO_2/MMBTU or less.

- The first contract is with Peabody's Twenty Mile mine in Colorado for 1 million tons per year for 2010 through 2012. This contract expires on December 31, 2012.

- The second contract is with Oxbow's Elk Creek mine in Colorado. The Oxbow contract is for 550,000 tons in 2011. This contract expires December 31, 2011.
- The third contract is for Powder River Basin (PRB) coal with Rio Tinto's Antelope mine in Wyoming. This contract is for 1 million tons per year in 2010 and 2011. This contract expires December 31, 2011.

Based on current burn projections and projected inventory carryover, Daniel is fully committed for 2010. There are no committed tons at Daniel for 2013 and beyond.

The following chart illustrates Gulf's 50 percent ownership in projected burn and commitments of coal for Daniel through 2015.

[redacted]

Gulf owns 25 percent of Unit 3 at Scherer. Scherer is classified as a New Source Performance Standard (NSPS) plant requiring the use of 1.2 lbs

SO_2/MMBTU or less. Scherer is 81 percent committed in 2010, with 10 long-term contracts in place supplying approximately 14.5 million tons for the total plant. Gulf's share of the burn years 2011 through 2013 are committed for 638,000 tons, 375,000 tons and 125,000 tons respectively.

The following chart illustrates Gulf's 25 percent ownership in Scherer Unit 3's projected burn and commitments of coal through 2015.

[redacted]

Procurement Strategy

The long-term coal procurement goal for Gulf is to provide a reliable, cost-competitive, environmentally acceptable coal supply. The successful coal program provides flexibility in volume and pricing, becomes more diverse by pursuing other supply regions, creates competition for supply, focuses on reliability of supply, and adheres to changing environmental laws and guidelines.

Over the past two years, the coal industry has become more susceptible to the influences of the global commodities market. Given the global market dynamics that occurred during this time frame, the coal market has reacted by becoming more volatile from both a pricing and volume availability standpoint. This has, in turn, impacted the dynamics between natural gas and coal, leading to increased uncertainty in coal burn.

The following section addresses the risks associated with each of these areas and identifies strategies to mitigate them. Also included in this section is a discussion of a strategic plan that incorporates several of these mitigation techniques.

Risks and Risk Mitigation Strategies

Volume Risk and Strategy

The uncertainty in the amount of coal generation and therefore coal supply that will be needed in the future is still one of the most critical risks that need to be addressed in developing a strategy for long-term coal procurement. [redacted]

[redacted] This increase in natural gas capacity within the Southern Company system in conjunction with the volatility of natural gas pricing will cause the amount of future coal generation to continue to become more uncertain. In addition, weather and economic growth will continue to impact future coal burn requirements.

[redacted]

[redacted]

[redacted]

[redacted]

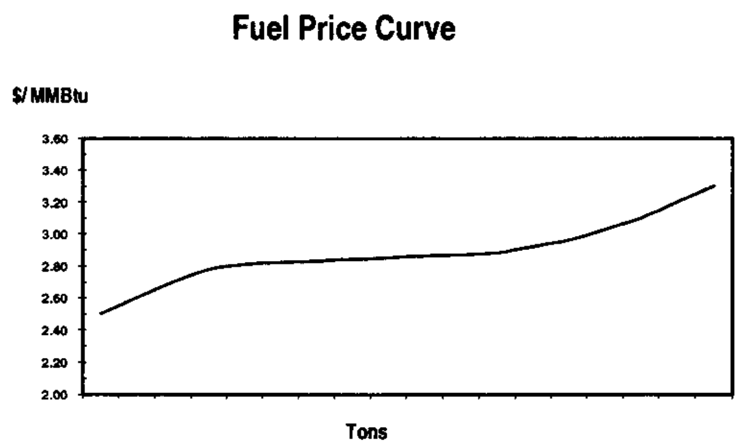
Pricing Risk and Strategy

Competing for energy market share with other utilities and power marketers requires competitive energy pricing. Because more than 50 percent of the cost for coal-fired generation is fuel, competitively priced coal supplies should be maintained.

The objective is to have a portfolio of long-term contracts and spot coal supplies that provide pricing at or below market at any given point in time. Where negotiations allow, mechanisms to achieve this objective include:

[redacted]

Due to the size of our system, the volume of purchases made at a particular time can impact the market. Ranking bid proposals in order of least cost and cumulative volume produces a price curve similar to the following:



[redacted]

Diversity of Supply Risk and Strategy

There is a risk in relying on one or two large producers from a single region to meet supply needs. Also, having the ability to burn coal from various regions will decrease the availability risk associated with lack of supply in a particular region. Diversifying will also keep the competition strong among the suppliers.

Close involvement with plant personnel will be required to actively pursue alternate sources, including testing and plant modifications if required.

[redacted]

Reliability Risk and Strategy

When a supply and demand imbalance occurs in the coal industry, reliability of supply poses a risk. Securing business with producers that have performed well during times of unreliable supply can mitigate that risk. Also, in addition to an economic evaluation, technical and financial evaluations of suppliers are now a required part of the coal procurement process.

[redacted]

[redacted]

Environmental Risk and Strategy

When procuring coal for a term greater than 12 months, a major risk factor is the potential impact of future changes in environmental laws and regulations that may render the burning of coal as non-economic to our system.

[redacted]

[redacted]

[redacted]

Strategic Plan

As mentioned above, when procuring coal for Gulf, the Crist and Smith plants will be grouped together because of their common supply source and transportation mode. Diversity of supply and flexibility will be important aspects of their fuel supply strategy.

On the other hand, Scholz can burn similar quality coals, but its transportation mode differs because it is rail served. The co-owned plants, Daniel and Scherer, will be treated individually.

Crist – In 2010, Crist coal transportation needs will be served by Marquette Barge Company. Crist burns approximately 3 million tons of coal a year and must comply with a state SO_2 emission limit of 2.4 lbs SO_2/MMBTU. For the past several years, Crist has burned low sulfur Illinois Basin coal from the Galatia mine. Crist can also burn Colombian import coals, as well as coals from Colorado, Utah and the Central Appalachian regions. Crist is considered an intermediate to baseload coal plant with a projected capacity factor of 78 percent.

Smith - Smith coal transportation needs will also be served by Marquette Barge Company. It burns approximately 1 million tons of coal a year and must comply with the state SO_2 emission limit of 2.1 lbs SO_2/MMBTU. Smith can burn a variety of coals, including Illinois Basin and import coals such as Colombian, Australian and Venezuelan. Domestic sources such as Colorado, Utah and Central Appalachian coals also have been burned in the past. Smith is considered an intermediate to baseload coal plant with a projected capacity factor of 79 percent.

<u>Scholz</u> –Scholz coal transportation need will be served by the CSX Railroad. It currently burns less than 60,000 tons of coal a year and must comply with a state SO_2 emission limit of 6.17 lbs SO_2/MMBTU. Scholz has burned Central Appalachian coals in the past. It currently has no commitments for 2010 and beyond. It is considered a peaking coal plant with a projected capacity factor of less than 50 percent.

<u>Daniel</u> –Daniel coal transportation needs will be served by the Mississippi Export Railroad (MSE) which is approximately 40 miles in length and runs between Moss Point and Evanston, Miss. The MSE is served by two large Class 1 railroads: the Canadian National Railroad connecting at Evanston and the CSX Railroad connecting at Moss Point. Classified as a NSPS plant, Daniel must use "compliance" coal with a maximum of 1.2 lbs SO_2/MMBtu (0.6 lbs Sulfur/MMBtu). Daniel can burn import coal in addition to coal from Colorado and the Central Appalachian regions. Powder River Basin coal is also burned in Daniel's units and blended with bituminous coal at an average of 60 percent bituminous /40 percent PRB ratio. Daniel is considered a baseload coal plant with a projected capacity factor of 80 percent.

Scherer –Scherer coal transportation needs will be served by a dual line haul involving the Burlington Northern Sante Fe (BNSF) and Norfolk Southern (NS) railroads. Scherer uses sub-bituminous PRB coal from Wyoming and is considered a baseload plant burning approximately 15 million tons of PRB coal per year. Classified as an NSPS plant, Scherer must burn "compliance" coal with a maximum of 1.2 lbs SO2/MMBtu (0.6 lbs sulfur/MMBtu). [redacted] Scherer Unit 3 is considered a base-load coal unit with a projected capacity factor greater than 88 percent.

[redacted]

The coal supply portfolio at Crist and Smith consists of the Interocean (old) contract with a volume commitment of 300,000 tons in 2010; the Interocean (new) contract with a volume commitment of 1.3 million tons in

2010; the American Galatia contract for 1 million tons in 2010 and 300,000 tons in 2011: the Oxbow contract with a volume commitment of 565,000 tons in 2010 and 485,000 tons in 2011; the Patriot contract with a volume commitment of 466,000 in 2010: the Consolidation contract with a volume commitment of 480,000 tons in 2010; and The American Coal Company's Utah coal with a volume commitment of 200,000 tons in 2010 and 188,000 tons in 2011.

Gulf has continued its testing program at Crist and Smith in order to diversify their supply of coals. The strategic objective will be to find alternative coal sources that will enhance Gulf's supply portfolio and meet Gulf's environmental restrictions.

Because Scholz is a peaking plant, its fuel supply will be based on limited-term, firm commitments and/or spot purchases depending on burn projections. Contract commitment terms will be two years or less. If commitments are made for more than 50 percent of projected burn requirements, the contract will match the maximum annual tonnage purchased to the plant burn requirements.

[redacted]

[redacted]

Traditionally, Daniel has used sources such as PRB and Colorado low-sulfur coals. Since 2000, market conditions -- including production problems, lack of availability of supply in some domestic regions and environmental awareness -- have emphasized the need to diversify with import coals. These other coal sources, transportation arrangements and plant quality limitations will be actively evaluated because of reliability and availability issues in the domestic market and in the existing Colombian market.

[redacted]

Scherer uses sub-bituminous PRB coal from Wyoming. Scherer is considered a baseload plant and burns approximately 14.5 million tons of PRB coal per year. [redacted]

[redacted]

Scherer can burn a wide range of PRB coals from the 8800 btu/lb mines located on the "joint line" south of Gillette, Wyoming, to the 8300 btu/lb mines located north of Gillette. This fact provides for a more diverse supply as well as more flexibility in transportation alternatives. With successful test burns of imported Indonesian coals in 2006, Scherer now has a proven substitute for PRB quality coals.

Environmental regulatory issues currently facing Gulf include compliance in accordance with the Acid Rain SO_2 provisions imposed by Title IV of the Clean Air Act Amendments. In the past, Title IV compliance was achieved by implementing an allowance strategy to bank, use and then buy allowances. Gulf's SO_2 allowance bank is currently healthy. Purchasing strategies for future needs are being developed that are sensitive to current year compliance as well as the risk of a significant change in the compliance regime in a few years.

In March 2005, the CAIR was signed. Phase I of this ruling subjected Gulf to an annual NOx cap and a state-wide seasonal NOx cap which began in 2009. CAIR also causes more stringent SO_2 compliance beginning in 2010, with two allowances required per ton of SO_2 emitted. In 2015, Phase II introduces even more stringent SO_2 and NOx compliance.

On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the Circuit Court of Appeals for the District of Columbia issued a decision vacating CAIR in its entirety and remanding it to EPA for further action consistent with its opinion. On December 23, 2008, the DC Circuit Court of Appeals remanded the rule to the EPA, allowing it to remain in effect until the EPA replaces it with an improved rule. The court did not establish a timeline for EPA action towards a revised rule, but did note that this remand was not an indefinite stay of the July 2008 decision.

The EPA released an update to the Regional Transport Rules (PM2.5) in September 2006. The new standards are more stringent than the current standards and will likely result in the designation in 2009 of a large number of new PM non-attainment areas across the United States. State recommendations for non-attainment areas for the revised standard were due in November 2007. The EPA will approve or disapprove the recommendations by November 2009.

In March 2008, EPA significantly strengthened its National Ambient Air Quality Standards (NAAQS) for ground-level ozone, setting the primary and secondary 8-hour ozone standard to 0.075 ppm. Large numbers of new ozone non-attainment areas will likely result from this action. The EPA will make final decisions on attainment, non-attainment, and unclassifiable areas by March 2010 based on state input.

Regional Transport Rules for both ozone and particulates will continue to be updated every five years, as required by NAAQS.

Southern Company and its subsidiaries are required to comply with the Clean Air Act Amendments of 1990 and with CAIR. This can be accomplished by purchasing emission allowances, the installation of various emission controls and by fuel switching. [redacted]

The near-term scrubber construction activities for Gulf are primarily focused on Crist. Crist's scrubber will come on line in December 2009 (4-7). [redacted] It is a single scrubber vessel serving all four units. The limestone grind size will be 90 percent passing a 325 mesh which will be supplied under contract from a third party regional grind facility which is being constructed in Mobile, AL by Mississippi Lime, Inc.

In the long-term, other Gulf scrubbers – perhaps on Smith 1-2 -- are in various stages of discussion and are subject to change.

Daniel's scrubber is now likely to come on line no sooner than late fall 2013 (1-2); although this is still under review. The scrubber has completed conceptual design but may be subject to change. [redacted] The design calls for a single scrubber vessel for both units.

Scherer Unit 3's scrubber is under construction and expected to be on-line in early January 2011. [redacted] The plant will have a scrubber vessel for each of the four units. The Scherer facility will be rail served and receive limestone in rock form for wet grinding on site. The limestone grind size will be 90 percent passing a 325 mesh (Advatech). [redacted]

[redacted]

Concurrent with ever tightening air regulations is concern over land disposal of byproducts from the burning of coal. Ash is the primary byproduct, but during the next few years, as scrubbers become operational, gypsum will be produced and is expected to be more than half the volume of ash. These byproducts, or coal combustion products (CCPs), present an O&M burden as well as extensive capital costs for construction of new landfills. As a measure to mitigate these costs and potentially produce some revenue, a CCP utilization program is in place. The objective of this program is to beneficially use CCPs in an environmentally safe method capturing cost savings for the rate.

Gulf produces about 250,000 tons of fly ash and 40,000 tons of bottom ash annually. Depending on the coal's ash content and economic dispatch of coal units, the future production level could vary. An RFP for ash marketing services at Crist was conducted in early 2008. As a result of that RFP an ash marketing agreement was negotiated but the execution was postponed due to the economic downturn that started in the second half of 2008. It is expected that this contract will move forward once the economy recovers. Once executed, the ash marketer will process the fly ash to improve its quality such that it can be used in ready mix concrete. This ash contract will result in the majority of ash produced at Crist being utilized being utilized and will provide a revenue source back to Gulf.

Crist's scrubber is projected to produce about 125,000 tons of gypsum annually. The gypsum will be processed to a marketable form and facilities put in place to transport by truck and barge to current markets. Currently, three markets are being pursued as outlets for Crist's gypsum: wallboard manufacturing, cement, and agricultural.

The long-term limestone procurement goal for Gulf is to provide an economic and reliable source of limestone in an immature market while contractually and physically mitigating risk. Below are potential risks associated with limestone procurement and the strategies that Gulf uses to mitigate those risks.

Gulf takes several steps to develop and maintain a reliable supply of limestone:

[redacted]

[redacted]

Gulf will also institute measures to address the unknown and immature limestone market. [redacted]

Another aspect of the purchasing strategy is to determine the form of limestone to procure. In order to maximize the removal of SO2, the limestone must be pulverized to a fine particulate form. Pulverizing limestone provides more surface area in which the flue gas can react. Limestone can be procured in a crushed form (i.e., 3/4 inches diameter) or in a pulverized form (i.e., 90 percent passing 325 mesh or 80 percent passing 200 mesh) from the market.

Additional factors such as fuel switching, increased load and low quality limestone can affect limestone demand. [redacted]

[redacted]

Each form offers a different risk and return profile. [redacted]

By outsourcing the pulverizing operation to the market, Gulf can avoid large capital costs associated with unloading equipment and grinders. [redacted]

Gulf's limestone procurement efforts have been primarily focused on the Crist and Daniel plants due to the near term in-service dates of the Flue Gas Desulfurization (FGD) or scrubber systems.

Crist and Daniel

Gulf has contracted with Mississippi Lime Company (MLC) to provide high calcium, pulverized limestone. Due to the close proximity to Alabama Power's (APC) Plant Barry, the system operating companies elected to take advantage of the economies of scale associated with combining volumes from all three plants. MLC will deliver crushed limestone to a central grinding location on Blakely Island (located near Mobile, AL) and pulverized limestone will be delivered to the plants via pneumatic discharge trucks from MLC's grinding facility.

As of December 2009, all four units will have FGD capability at Crist; which is expected to consume approximately 50,000 to 80,000 tons per year based on current load projections and current sulfur assumptions. [redacted]

Daniel is tentatively planned to begin FGD operations in the April 2013 timeframe and expected to require 30,000 to 60,000 tons of limestone per year.

In the future, assuming the plant is scrubbed, limestone procurement activities will be focused on Smith. [redacted] Gulf will also look at possible crushed sources to determine the most cost effective supply.

Tactical Plan

There are several issues facing the long-term Gulf coal procurement program. They are:

- Gulf has no committed coal for 2012 and beyond at Crist and Smith.

- Scrubber installation at Daniel Units 1 and 2 in 2013.
- Scrubber installation at Scherer Unit 3 in 2011.
- Limestone procurement.

<u>Crist and Smith</u>

The chart below shows a breakdown of the current Crist and Smith suppliers and volume commitments, including options, through 2015.

[redacted]

[redacted]

[redacted]

[redacted]. This has

been accomplished by testing other import coals such as Russian, La Jagua Colombian, Calenturitas Colombian, and other domestic coals such as lower sulfur Illinois Basin coals. Gulf has undertaken testing coals from other supply regions such as the Central Appalachian region and the Western bituminous regions of Colorado and Utah. These coals will be delivered by rail to the Alabama State Docks (ASD) in Mobile, Alabama.

As an example, during the market run-up in the first half of 2008, Gulf further diversified its supply by purchasing a portion of its need from the Western bituminous coal supply region, including Colorado and Utah, as well as coal from the Central Appalachian region.

The ASD has completed the project to upgrade the rail unloading facility at the Bulk Terminal. This will allow the unloading of rail coal at this facility. Shipments can also be delivered to various ports along the Mississippi River and transloaded into barges for ultimate delivery to Crist and Smith.

There is no uncommitted need at Crist and Smith in 2010. [redacted]

This, of course, will depend on the future state of the coal market. [redacted]

The installation of a scrubber at Crist 4 - 7 will be complete by December 31, 2009. Crist has burned coal from multiple regions, including various imports, Central Appalachian, Western bituminous and Illinois Basin coals. If required, a test burn program will be initiated in 2011 from the long-term RFP to determine the impact of these coals on the scrubbed units at Crist.

[redacted]

Both Illinois Basin and Central Appalachian coals can either be barged directly to Crist and Smith or railed to the ASD and transloaded into barges. With the exception of the improvements to ASD's Bulk Terminal, no transportation infrastructure improvements will be necessary for the movement of these coals to Gulf's plants. At this time, it is unknown whether the plant will need some time to acquire additional equipment for burning large volumes of the Illinois Basin coals.

Scholz

The chart below shows a breakdown of the current Scholz suppliers and volume commitment, including options, through 2011.

As mentioned previously, Scholz is served by the CSX Railroad. Scholz's burn fluctuates between 24,000 tons in 2010 and 60,000 tons in 2011. Scholz is scheduled to be retired in December 2011. Scholz is rail served and has no coal commitments in place for 2010 or 2011. Any uncommitted need will be satisfied with existing coal inventory on the ground at the plant.

Daniel

The chart below shows a breakdown of the current Daniel suppliers and volume commitments, including options, through 2015.

[redacted]

[redacted]

[redacted]

[redacted]

The remaining needs will be secured through the RFP process. The goal for future years, if economics warrant, would be to maintain this diversity. Should supply problems occur, this diverse portfolio of suppliers would help ensure that the other suppliers could continue seamless deliveries to the plant. Another important element of this diversification philosophy is that Daniel can share most coal supplies with MPC's Watson plant should operational, supply, or transportation problems occur at either plant. Gulf will also continue its policy of testing various import as well as domestic coals.

In addition to receiving import coal through the ASD, Daniel also has the ability to take imported rail coal through the Illinois Central Rail Marine Terminal (ICRMT) in Convent, La. This is a proven facility that Daniel has used in the past. Because it is an inland-river facility capable of unloading Panamax-sized vessels, it provides additional security during hurricane season.

The installation of a scrubber at Daniel 1 - 2 is tentatively scheduled for late 2013. Daniel is an NSPS plant and has historically burned compliance coal (1.2 lbs SO_2/MMBtu maximum). As mentioned above, Daniel has burned coal from multiple regions including various imports, Central Appalachian and Colorado coals. A test burn program will be initiated in 2013, depending on the actual installation date, to determine the impact that these coals will have on the scrubbed units at Daniel. [redacted]

Both Illinois Basin and Central Appalachian coals can be railed directly to Daniel, although some infrastructure improvements would be necessary. At this time, it is uncertain if the plant will need some time to acquire additional plant equipment necessary for burning Illinois Basin coals. The procurement group will need to be cognizant of the environmental controls placed on the units and ensure that the coals purchased will meet the environmental requirements.

Scherer

The chart below shows a breakdown of Gulf's 25 percent ownership of Scherer's Unit 3 suppliers and volume commitments, including volume options, through 2015.

[redacted]

[redacted]

[redacted]

The installation of scrubbers is planned for Scherer beginning with Unit 3 in 2011. Procurement strategies in the future will need to be cognizant of the environmental controls placed on the units to ensure that the coals purchased will meet the environmental requirements.

It is clear that PRB coal currently represents the lowest delivered cost and a vast supply resource for Scherer. However, it is also recognized:

- Coal market economics are dynamic and may change dramatically from time to time
- The availability of particular coal sources may become constrained and in those instances, alternate coal source options must be considered.

To maintain the competitiveness and reliability of Scherer's generating assets, it is strongly recommended that fuel supply flexibility be maintained as much as is economically feasible.

In summary, the following procurement plan will be put into place:

[redacted]

[redacted]

[redacted]

[redacted]

The procurement group will need to be cognizant of the environmental controls placed on all of its units to ensure that the coals purchased will meet the environmental requirements.

GULF POWER
TRANSPORTATION STRATEGY
AUGUST 2009

Introduction

Gulf Power Company (Gulf) operates three coal-fueled plants with a combined normal full load gross rating of 1,379 megawatts and with annual coal consumption projected at more than 4 million tons. Gulf uses railcars and barges to transport coal to its plants. In 2008, coal represented more than 84 percent of Gulf's generation sources. Gulf also co-owns 50 percent of Plant Daniel, which is operated by Mississippi Power Company (MPC) and has a projected annual coal consumption of 1.5 million tons. Transportation of this coal is critical to the company's ability to serve its customers.

The highest priority for a coal transportation strategy is to maintain a reliable, cost-competitive transportation system. Increasing competition in the electric utility industry, demand/supply imbalance in the coal transportation industry, the changing location of coal supply sources, compliance with environmental regulations, and the performance capabilities of transportation providers are just a few of the challenges that must be addressed when developing a transportation strategy.

The following is:

- A review of the current coal transportation program, including current agreements, available mode of transportation, and budget.
- A transportation strategy that identifies and addresses specific risks and risk mitigation strategies.
- A tactical plan detailing specific actions required in order to achieve the strategy.
- An overview of the transportation strategy for the movement of limestone and gypsum, including contracts in place or under negotiation.

TRANSPORTATION PROGRAM OVERVIEW

Plants Crist and Smith

Crist and Smith have the ability to receive both import and domestic coal by barge. Western coals can be transported by the Burlington Northern Santa Fe Railroad (BNSF) or the Union Pacific Railroad (UP) to terminals on the Mississippi River or via the Canadian National Railway (CN) to the Alabama State Docks facility in Mobile, Ala., and then barged to the plants. Illinois Basin or Central Appalachian coal can be transported by barge or by a combination of rail and barge to these plants as well.

Eastern coal can be transloaded at the Alabama State Docks Facility in Mobile, Ala., via interchanges with the Canadian National Railway (CN), CSX

Transportation Inc. (CSXT), Alabama Gulf Coast Railroad (AGCRR), and Norfolk Southern (NS) railroads. Import coal can be delivered by ocean vessel to the Alabama State Docks facility for barge movement to the plants. Currently, Crist and Smith receive import coal, Illinois Basin coal, and coal from Colorado and Utah.

Crist and Smith are served by a single barge carrier. Ingram Barge Agreement (GU72001-B) provides for transportation to both plants from various Central Appalachian and Illinois Basin River terminals on the Mississippi and Ohio rivers and from Gulf Coast terminals to Crist and Smith. The agreement expires Dec. 31, 2009. During the term of this agreement, 100 percent of waterborne tonnage transported to Crist and Smith must be offered to Ingram.

Plant Scholz

Scholz is rail served by the CSXT railroad. The plant has the ability to receive both domestic and import coal. Import coal could be brought into the Alabama State Docks facility and then transloaded into railcars for movement to the plant.

Scholz has an agreement with the CSXT Railroad (CSXT-C-83791) that expires Dec. 31, 2011, which is the plant's expected retirement date. This agreement specifies that 95 percent of all deliveries must move on the CSXT railroad. If Scholz is retired earlier than expected, there will not be any penalties because of the minimum volume language.

Plant Daniel

Daniel is served by the Mississippi Export Railroad (MSE) that interchanges with the CSXT and the CN. Daniel accesses Powder River Basin (PRB) and Colorado coal sources via multiple line hauls to the MSE from the BNSF, UP, and CN railroads.

Daniel can also take advantage of import coals, when economical, through the Alabama State Docks facility located at the Port of Mobile. Import coal is transloaded from an ocean vessel at the Alabama State Docks facility to railcars for shipment to the plant by the CN and interchange with the MSE. Daniel can also receive Central Appalachian coal via the CSXT and interchange with the MSE. Another potential source of Central Appalachian coal is via the NS railroad through an interchange agreement with the CN railroad. Currently, Daniel receives Colorado, PRB, and import coal.

[redacted]

[redacted]

[redacted]

CN/MSE Tariff Agreement CN-665098AB provides for rail transportation of import coal from the Alabama State Docks facility to Daniel. The tariff rate expires Dec. 31, 2009. The tariff has no minimum volume requirements.

Budget

[redacted]

[redacted]

The chart below shows the forecasted coal volume and transportation costs for Gulf's coal-fueled plants.

[redacted]

Coal Transportation Procurement Strategy

A transportation strategy must address reliability, competitive prices, flexibility in volume commitments, and the ability to adjust coal movements to changing coal supply sources. The following information will address the risks associated with each of these areas and identifies strategies to mitigate them.

RISKS AND RISK MITIGATION STRATEGIES

Reliability Risk and Strategy

Reliable delivery of coal ensures that fuel will be available to generate electricity. Term agreements will be negotiated and signed with the transportation carriers that ensure the barge and rail companies will have available infrastructure and resources in place to transport the required coal supply. The terms of the transportation agreements will coincide with the terms of single source coal supply agreements as closely as possible.

[redacted]

Communication between Gulf's coal operating personnel, each plant, Southern Company Generation Fuel Services, and the various carriers is vital in maintaining reliable and efficient operations. Effective and timely communication of transportation plans, orders, problems, and maintenance is critical.

Pricing Risk and Strategy

Competition is created with diversity of coal supply sources and alternative transportation modes at each of the plants. Competition is achieved by periodically bidding transportation alternatives and educating carriers on the effects of marginal dispatch changes on unit load requirements.

[redacted]

Volume Risk and Strategy

The uncertainty in the amount of coal generation and transportation that will be needed in the future is still one of the most critical risks that must be addressed in developing a strategy for long-term transportation procurement. Weather, natural gas pricing, and economic growth will continue to impact future coal burn requirements, as will the addition of gas-fired capacity to the Southern Company system. Over the past two years, the coal industry has become more susceptible to the influences of the global commodities market. Given the global market dynamics that occurred during this time frame, the coal market has reacted by becoming more volatile from both a pricing and volume availability standpoint. This has, in turn, impacted the dynamics between natural gas and coal, leading to increased uncertainty in coal burn.

[redacted]

[redacted]

Supply Risk and Strategy

It is desirable to have multiple transportation modes and carriers in case there is a rail and/or barge accident that might disrupt the supply chain. Diversity of transportation modes and carriers is also vital because the location of coal supply sources changes as environmental laws and regulations evolve and as coal is depleted in established regions.

It is vital to the success of a coal and transportation program to ensure infrastructure is in place to move the coal from changing locations as this occurs. This may include enhancements to existing facilities or the development of new facilities.

The Alabama State Docks' McDuffie Coal Terminal has the capacity to receive approximately 16 million tons of import coal per year. In addition, the Alabama State Docks recently completed the Bulk Unloader Railcar Project at the Alabama State Docks' Bulk Materials Handling Plant (Bulk Plant). The upgrade of railcar handling facilities provide the Bulk Plant with the ability to receive an additional 3 million tons of coal per year by rail.

TACTICAL PLAN

Plants Crist and Smith

Ingram Agreement (GU72001-B) provides for barge transportation to Crist and Smith. This agreement will expire Dec. 31, 2009.

The tactical plan is to replace this expiring agreement prior to the expiration date. As agent for Gulf and MPC, Southern Company Generation Fuel Services issued a Request for Proposals on Sept. 16, 2008, to solicit bids for new barge transportation service to Crist and Smith and to MPC's Plant Watson. Based on evaluation of the bids, two vendors were selected to provide barge transportation service to Crist, Smith and Watson. Marquette Transportation was selected to provide towboat services and provide a share of the barges. Heartland Barge was selected to provide the balance of barges that will be used to transport coal to Crist, Smith and Watson.

[redacted] The contracts will be finalized prior to the expiration of the contract with Ingram Corporation.

Plant Scholz

Scholz has an agreement with the CSXT Railroad (CSXT-C-83791) that expires Dec. 31, 2011, which is the plant's expected retirement date.

The tactical plan for this agreement will be to closely monitor the retirement date for this plant and work with CSXT to improve operational efficiencies in order to minimize transportation-related costs to Scholz.

Plant Daniel

[redacted]

The tactical plan for this UP agreement is to continue to support coal movements and to identify opportunities to improve operational efficiencies with the rail carriers and the plant.

[redacted]

The tactical plan for this BNSF agreement is to continue to support coal movements and to identify opportunities to improve operational efficiencies with the rail carriers and the plant.

CN/MSE Tariff Agreement CN-665098AB provides for rail transportation of import coal from the Alabama State Docks facility to Daniel. The tariff rate expires Dec. 31, 2009.

The tactical plan is to renegotiate this agreement for Daniel prior to the expiration date.

<u>Mineral (Limestone and Gypsum)</u>

Installations of flue-gas desulfurization systems (i.e., scrubbers) will create the need for transportation services for the mineral products such as limestone. In addition, operation of these systems produces gypsum as a byproduct that must be disposed of or marketed for beneficial uses.

Risk mitigation techniques in the coal transportation strategies are also applicable for mineral transportation. Application of these strategies shall be tempered by construction timetables, timing of mineral purchases, sourcing of limestone, limestone volumes, disposal or sales of gypsum, and the applicable transportation mode.

Preliminary cost estimates of transportation options are provided upon request to combustion by-products specialists. For planning purposes, this information is provided as early as 5 years before the scrubber begins operating. Procurement of transportation does not occur prior to procurement of minerals agreement. The term of the transportation agreement shall be no longer than the term of the minerals agreement.

The long-term transportation goal will be to provide a reliable, cost-competitive transportation system for the movement of minerals and scrubber by-products, as needed. The limestone procurement strategy at this time is focused on Crist.

A scrubber is currently under construction at Crist and is scheduled to be placed in-service in December 2009. The source of Crist's limestone will be a regional grinding facility near Mobile, Ala., that is currently under construction. The grinding facility will be owned and operated by Mississippi Lime Co. Mississippi Lime will deliver pulverized limestone by truck FOB to Crist.

[redacted]

Gulf Power's Natural Gas Procurement Strategy August 2009

Gas Program Overview

Natural Gas is used for primary fuel at the Smith 3 combined cycle unit, boiler lighter fuel at Crist Units 4-7, and for peaking generation secured under purchased power agreements beginning in 2009. Prior to 2002, natural gas represented a relatively small portion of Gulf's overall fuel budget. With the addition of the Smith 3 combined-cycle unit in 2002, natural gas became a more significant portion of Gulf's overall fuel budget.

Gulf Power's natural gas procurement strategy is to purchase a cost effective yet highly reliable fuel supply to support the operation of its generating facilities. Securing competitive fuel prices for its customers and minimizing both price and supply risk are the governing considerations in developing Gulf's fuel procurement strategy.

Projected Natural Gas Purchases

Southern Company Services (SCS) as agent for Gulf purchases natural gas to be delivered to Plant Crist for lighter purposes on the coal fired units and to Plant Smith as primary fuel for Unit 3 which is a combined cycle generating unit. SCS will also purchase natural gas to serve as primary fuel for the Coral (Baconton) and Southern Power (Dahlberg) purchased power agreements. Gulf has contracted for storage capacity at Bay Gas Storage near Mobile, AL and at Southern Pines Energy Center near Hattiesburg, MS and will purchase natural gas to maintain targeted quantities of gas in storage during the year. The following chart shows the total projected gas burn for 2010 through 2013 in MMBTU that these purchases will support:

PROJECTED NATURAL GAS BURN (MMBTU)

Month	2010	2011	2012	2013
January	25678	[redacted]	[redacted]	[redacted]
February	511248	[redacted]	[redacted]	[redacted]
March	1151522	[redacted]	[redacted]	[redacted]
April	1634771	[redacted]	[redacted]	[redacted]
May	1627560	[redacted]	[redacted]	[redacted]
June	1366728	[redacted]	[redacted]	[redacted]
July	1520126	[redacted]	[redacted]	[redacted]
August	1290826	[redacted]	[redacted]	[redacted]
September	1118224	[redacted]	[redacted]	[redacted]
October	1169487	[redacted]	[redacted]	[redacted]
November	672369	[redacted]	[redacted]	[redacted]
December	330826	[redacted]	[redacted]	[redacted]
TOTAL	**12419365**	[redacted]	[redacted]	[redacted]

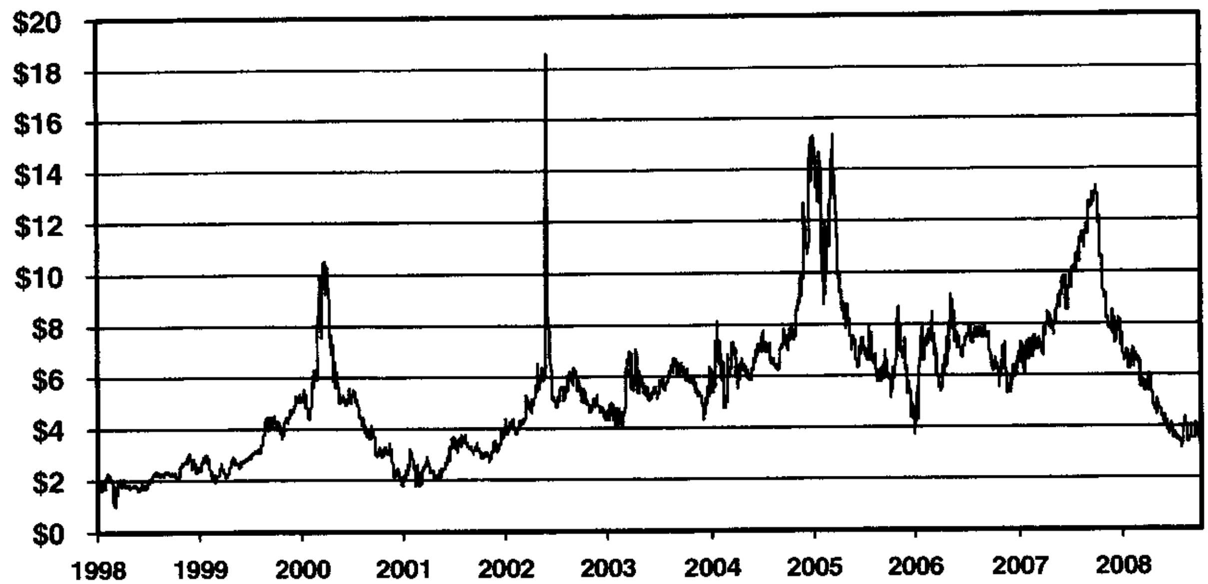
Procurement Strategy

Gulf's strategy for gas procurement is to purchase the commodity using long term and spot agreements at market prices. Fuel purchased at market over a long period is a low cost option for customers [redacted]

For Gulf, spot-market contracts have a term of less than one year and long-term contracts have a term of 1 year or longer. All natural gas, regardless of whether it is bought under long-term contracts or spot-market contracts, is purchased at market based prices. While fuel purchased at market over long periods is a low cost option for customers, it does expose the customers to short-term price volatility. Since these price fluctuations can be severe, Gulf Power, at the direction of the Florida Public Service Commission, will attempt to protect its customers against short-term price volatility by utilizing hedging tools. It is understood that the cost of hedging will sometimes lead to fuel costs that are higher than market prices but that this is a reasonable trade-off for reducing the customers' exposure to fuel cost increases that would result if fuel prices actually settle at higher prices than when the hedges were placed.

The following graph of actual natural gas prices is an indication of price volatility in the gas commodity market:

Historical Natural Gas Prices - NYMEX



Pricing Strategy

Gulf Power will continue to purchase gas, both under long-term and spot contracts at market based prices. However, pursuant to Commission order, Gulf Power will financially hedge gas prices for some portion, generally [redacted] of Gulf Power's projected annual gas burn for the current year, in order to protect against short-term price swings and to provide some level of price certainty. This [redacted] hedge range allows Gulf Power to provide a degree of price certainty and protection against short-term price swings while still allowing the customers to participate in markets where natural gas prices are low. Gulf Power will secure natural gas hedges over a time period not to exceed [redacted], per the following schedule:

Period	**Min. Hedge %**	**Upper Target Hedge %**
Prompt Year (2010)	[redacted]	[redacted]
Year 2 (2011)	[redacted]	[redacted]
Year 3 (2012)	[redacted]	[redacted]
Year 4 (2013)	[redacted]	[redacted]
Year 5 (2014)	[redacted]	[redacted]

Note: The annual hedge percentage is based on the budgeted annual gas burn

Although SCS will target the levels shown in the table above, if extreme market conditions exist, SCS may accelerate or decelerate the plan accordingly. Gulf's hedging targets are expressed on an annual basis due to the potential for large variances in month to month gas consumption. The monthly variance in gas burn is due to Gulf's ownership of only one gas fired generating unit that is dispatched on an economic basis with the other generating units in the Southern electric system and the impact of unit outages on Gulf's total gas burn.

SCS, working in partnership with Gulf Power, develops short-term hedge strategies based on current and projected market conditions. [redacted] SCS will employ both technical and fundamental analysis to determine appropriate times to hedge;

however, the objective is not to speculate on market price or attempt to outguess or "beat the market". Gulf will utilize fixed priced swaps as its primary financial gas price hedging instrument but may also utilize options to a lesser degree when appropriate.

While the hedging program will protect the customer from short-term price spikes, hedges can also lead to higher costs when natural gas prices fall subsequent to entering hedges. Gulf Power will limit the amount of fixed-price hedges to a maximum of 100 percent of the projected fuel burn for the upcoming year. In addition, Gulf Power will limit option priced hedges to 110 percent of its projected burn. [redacted]

System Hedges

Because Gulf Power is a part of the Southern Electric System (SES), it indirectly participates in gas hedging for fuel price indexed power related transactions done on behalf of the SES. These hedges are referred to as "system hedges." In these instances, Southern Company Services utilizes financial hedging instruments to mitigate fuel price risk related to individual power transactions. Gulf is allocated its portion of these gas hedges when they occur based on its peak period load ratio. All system hedges are matched to individual power transactions and are considered separate from Gulf's directed hedging program for gas burn at generating units where it directly purchases natural gas supply.

Gulf Power's Oil Procurement Strategy

Oil Program Overview

Oil is used at Gulf predominantly for boiler lighting. Oil is used as a boiler lighter fuel at Crist 4-7, Daniel 1&2, Scherer 3, Scholz 1&2 and Smith 1&2. Oil is also the primary fuel at the Smith A CT unit and as back-up fuel at the Coral (Baconton) and Southern Power (Dahlberg) CT units currently under purchase power agreements with Gulf. Overall, oil use is projected to be a small portion of Gulf's overall fuel budget.

Procurement Strategy

Gulf's strategy for oil procurement is to purchase the commodity at market prices. Fuel purchased at market over a long period is a low cost option for customers.

Gulf purchases fuel oil on an annual basis through a formal bidding process. As part of this bidding process, Gulf negotiates predetermined contracts to set the index based market price for the commodity and delivery adders for fuel oil delivery to each plant. As inventories are depleted during the year, Gulf will purchase additional fuel oil quantities based on the negotiated contract for the plant.

Pricing Strategy

Since fuel oil is such a small portion of the overall fuel budget, Gulf does not currently plan to financially hedge oil prices.

Gulf Power Company Risk Management Policy

I. Introduction

Natural gas has become a large part of the Gulf Power Company (Company) fuel program. This increased need, combined with the market price volatility associated with natural gas and purchased energy, has created a need to begin hedging the risks related to the Company's overall fuel program.

II. Objectives

The primary objective of this Risk Management Policy (RMP) is to establish guidelines for use of hedging transactions associated with the Company's fuel program. Hedging transactions will allow the Company to:

- Reduce price volatility
- Provide more predictable stability to customers, and
- Provide additional flexibility and options in the procurement of fuel.

III. Guidelines

The risk management guidelines of The Southern Company require any business unit engaging in risk management activities to establish a Risk Oversight

Committee (ROC). The officer listed below in Section IV will serve as the Company's ROC for this program.

The Southern Company Derivatives Policy states:

> "It is the policy of The Southern Company that derivatives are to be used only in a controlled manner, which includes identification, measurement, management, control and monitoring of risks. This includes, but is not limited to, well-defined segregation of duties, limits on capital at risk, and established credit policies. When the use of derivatives is contemplated, this policy requires that a formal risk management plan be developed that adheres to The Southern Company Risk Oversight Committee Business Unit Guidelines. This policy also requires that, prior to initiation of a risk management program that makes use of derivatives, the risk management program must be approved by both the Chief Financial Officer of the respective Southern Company subsidiary and the Chief Financial Officer of The Southern Company."

The Southern Company Generation Risk Management Policy (SCGen RMP), attached in Section 6 of this document, will be the governing policy in the administration of the Company's fuel procurement program. The SCGen RMP provides all criteria specified in the above extract from the Southern Company Derivatives Policy.

The Gulf Power Company Board of Directors has authorized the use of hedging transactions relating to contracts and other agreements for fuel supplies. The board resolution is shown below:

"**RESOLVED,** That The Southern Company System Policy on Use of Derivatives (the "Policy") as presented to the meeting is hereby approved; and

RESOLVED FURTHER, That the Officers are hereby authorized to effect derivative transactions that comply with the policy, including swaps, caps, collars, floors, swap options, futures, forward and options, relating to energy and associated commodities, weather, interest rates, currencies, and contracts and other arrangements for fuel supplies; and

RESOLVED FURTHER, That in connection with the foregoing, the officers are hereby authorized to take any and all actions and to execute, deliver and perform on behalf of the Company any and all agreements and other instruments as they consider necessary, appropriate or advisable, each such agreement or other instrument to be in such form as the officers executing the same shall approve, the execution thereof to constitute conclusive evidence of such approval."

IV. Process

Certain officers of the Company were given authority to enter into hedging transactions that they consider necessary in order to reduce risk associated with procuring fuel and energy. The authorized officer, is the Vice President and Chief Financial Officer for Gulf Power Company or his designee.

Once authorization has been received, Southern Company Services Fuel Services, agent for Gulf Power Company, will conduct all hedging transactions in accordance with the Southern Company Generation Risk Management Policy.

It is the responsibility of SCGen Risk Control (the mid-office) to inform the Fuel Manager for Gulf Power Company or the Comptroller for Gulf Power Company about the use of hedging transactions associated with Gulf generation resources and to provide open position values (mark to market) to the above noted individuals and Gulf's Chief Financial Officer.

Southern Company
Energy Trading Risk Management Policy

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L. Definitions L–1

I. Introduction

In August 1997 the Southern Company Risk Oversight Committee approved a set of risk management guidelines. Also, at various times during 2000 through 2002, the boards of directors for Southern Company, the Operating Companies, and Southern Power Company adopted the Southern Company Policy on the Use of Derivatives ("Derivatives Policy"). During 2006, the risk oversight and governance framework for Southern Company continued to evolve to further refine the oversight structure and to reflect organizational changes since the original Southern Company Risk Oversight Committee (SROC) approved risk management guidelines in August 1997. As part of this evolution, the Southern Company Risk Oversight Committee was reconstituted, and a Generation Risk Oversight Committee was formed. These groups, along with the newly formed Risk Advisory and Controls Committee, replaced the Energy Risk Management Board and assumed its responsibilities.

Effective November 19, 2007, certain functions for Southern Power were separated from the other Southern Operating Companies and certain communications between them was restricted. It was decided that, Southern Power would no longer attend or have representation on the Generation Risk Oversight Committee. This decision prompted the need for a Southern Power Risk Oversight Committee and separate Southern Power risk monitoring. The Generation Risk Oversight Committee will continue to monitor the consolidated energy trading risks, including Southern Power positions.

The Southern Company Derivatives Policy requires any business unit engaging in energy trading and marketing activities to develop a risk management policy. This policy must be consistent with the Southern Company Enterprise Risk Management Policy and Framework document; and must include, but not be limited to, well-defined segregation of duties, limits on capital at risk and established credit policies.

II. Purpose

[redacted]

[redacted]

[redacted]

III. Business Objectives

The Approved Business Objectives for the trading activities performed on the Trading Floors are defined in Appendix A.

III. Business Strategies

The business objectives are achieved by entering into transactions involving the approved commodities shown in Appendix B.

[redacted]

[redacted]

Various contract types or financial instruments will be used to achieve the Approved Business Objectives. The Approved Risk Management Instruments are listed in Appendix C.

IV. Authorizations

Appendix D contains the individuals, boards, and committees authorized to carry out various activities, reviews, and approvals.

V. Segregation of Duties

The following functions are separated to ensure that the risk management activities are properly carried out:

- Origination and Structuring
- Confirmation
- Monitoring and reporting
- Settlement
- Cash management
- Accounting

[redacted]

Appendix E represents the functional separation organizationally as specified in this RMP. The following is a summary of the responsibilities of the different functions:

<u>Origination and Structuring:</u> The functions of origination and structuring include the following responsibilities:

[redacted]

<u>Confirmation, Monitoring, and Reporting</u>: The functions of trade confirmation, risk monitoring, and risk reporting include the following responsibilities:

[redacted]

[redacted]

Settlement: The function of settlement includes the following responsibilities:

[redacted]

Cash Management: SCS Treasury is responsible for receiving and disbursing all funds from or to counterparties and for the delivery of margin / collateral requirements. SCS Treasury will also be responsible for investment of collateral provided by counterparties.

Accounting: SCS Accounting is responsible for posting transactions to the general ledger and reconciling the subledgers to the general ledger.

VII. Market Risk Identification

[redacted]

VIII. Market Risk Measurement and Valuation

[redacted]

IX. Market Risk Limits

Exposure Limits	The maximum exposure limits are shown in Appendix H. the maximum exposure limit for each business objective should not exceed the limits specified in Appendix H.

Notification	Certain notifications to management are required as defined in Appendix G.
Limit Excess Reporting	Irrespective of other provisions contained in this RMP, limit overages may occur. Each occurrence shall be promptly reported by the middle office to individuals identified in Appendix G.

X. Credit Risk

[redacted]

XI. New Products

[redacted]

[redacted]

XII. Funding Liquidity

[redacted]

XIII. Operating Procedures and Systems

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

XIV. Accounting and Tax

[redacted]

[redacted] Appendix J contains the accounting and tax approach that will be utilized for the Trading Floors' risk management activities.

XV. Legal

Legal counsel will be retained to assist in managing the legal and regulatory aspects of the energy risk management activities covered by this RMP. Legal counsel will be retained for advice on contracts and will submit regulatory filings to ensure that energy risk management activities comply with the regulatory requirements of various agencies. In addition, legal counsel assists in the development of initial master purchase and sales agreements including credit terms and confirmation format. Legal counsel also reviews contracts and nonstandard confirmation documents.

XVI. Monitoring and Reporting

Middle Office personnel will calculate and report the following items on a daily basis:

[redacted]

[redacted]

XVII. Personal Trading

[redacted]

XVIII. Business Recovery

[redacted]

XIX. Compliance

[redacted]

[redacted]

XX. Independent Review

[redacted]

[redacted]

XXI. Policy Amendments

[redacted]

XXII. Terminology

Definitions of terminology used in this RMP are contained in appendix L.

APPENDIX A

APPROVED BUSINESS OBJECTIVES

ENERGY TRADING AND MARKETING

Fleet Operations and Trading

The primary objectives of Fleet Operations and Trading are to:

[redacted]

Southern Power Company Trading & Asset Management

The primary objectives of the Southern Power Company Trading and Asset Management activities are the following:

[redacted]

FUEL SERVICES

Natural Gas Fulfillment Function

The primary objectives of the Natural Gas Fulfillment Function are to: [redacted]

Secondary activities of the natural gas fulfillment function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading.

Emission Allowance Management Function

The primary objectives of the Emissions Allowance management function are to: [redacted]

Secondary activities of the emission allowance management function are restricted to positions intended to hedge secondary power positions, and which have been requested by

Fleet Operations and Trading.

Coal Fulfillment Function

The primary objectives of the Coal fulfillment function are to: [redacted]

Secondary activities of the coal fulfillment function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading.

Renewable Energy Credits (REC) Fulfillment Function

The primary objectives of the REC fulfillment function are to: [redacted]

Secondary activities of the REC fulfillment function are restricted to positions intended to hedge secondary power positions, and which have been requested by Fleet Operations and Trading.

APPENDIX B

APPROVED COMMODITIES

The approved commodities for this RMP are:

- Electric power
- Natural gas
- Coal
- Emissions Allowances
- Oil products
- Renewable Energy Certificates (RECs)

APPENDIX C

APPROVED INSTRUMENTS

The approved instruments are:

[redacted]

APPENDIX D

AUTHORIZATIONS

Name	Authority
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

APPENDIX D

AUTHORIZATIONS (continued)

Energy Marketing

Name	Authority
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

APPENDIX D

AUTHORIZATIONS (continued)

SCS Fuel Services

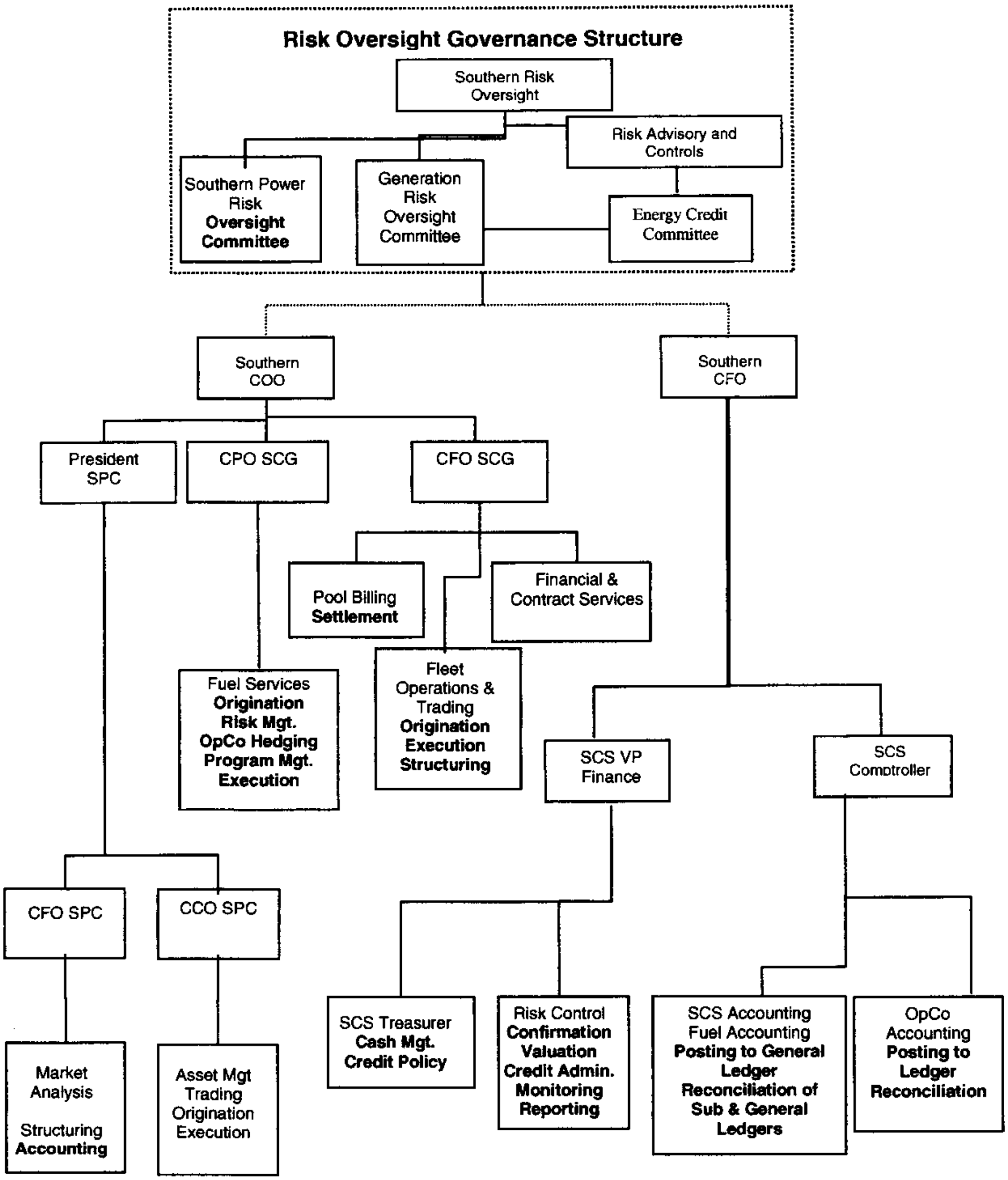
Name	Authority
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

APPENDIX E

SEGREGATION OF DUTIES

To ensure that risk management activities are properly carried out, certain functions will be separated. The following chart identifies these functions (depicted as **BOLD** bullet items) and their reporting process.


Risk Oversight Governance Structure
Southern Risk Oversight
Risk Advisory and Controls
Southern Power Risk Oversight Committee
Generation Risk Oversight Committee
Energy Credit Committee
Southern COO
Southern CFO
President SPC
CPO SCG
CFO SCG
Pool Billing Settlement
Financial & Contract Services
Fuel Services Origination Risk Mgt. OpCo Hedging Program Mgt. Execution
Fleet Operations & Trading Origination Execution Structuring
SCS VP Finance
SCS Comptroller
CFO SPC
CCO SPC
SCS Treasurer Cash Mgt. Credit Policy
Risk Control Confirmation Valuation Credit Admin. Monitoring Reporting
SCS Accounting Fuel Accounting Posting to General Ledger Reconciliation of Sub & General Ledgers
OpCo Accounting Posting to Ledger Reconciliation
Market Analysis Structuring Accounting
Asset Mgt Trading Origination Execution

1

APPENDIX F

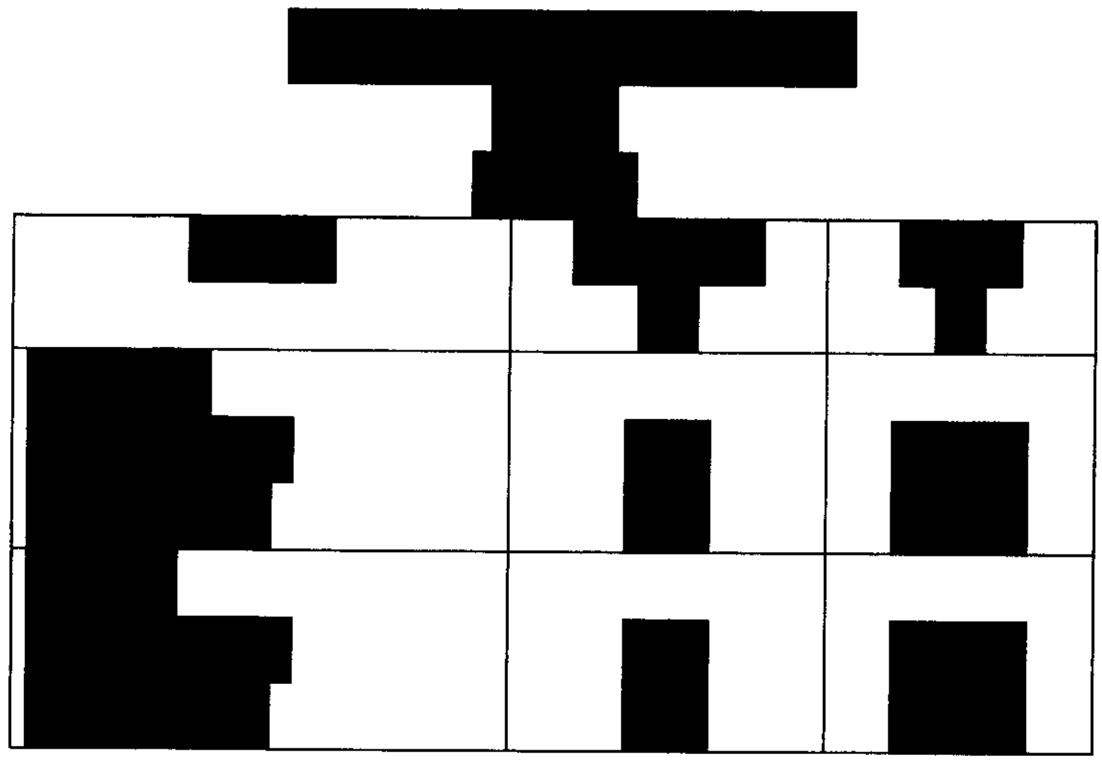
MARKET RISK MEASUREMENT

Approved Commodities	Value at Risk Method
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]



APPENDIX F

STRESS TESTING METHODOLOGY

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

Ad Hoc Stress Testing

[redacted]

APPENDIX G

NOTIFICATION LEVELS

Position Classification	Income Change	Notify
[redacted]	[redacted] [redacted] [redacted]	[redacted] [redacted] [redacted] [redacted]
[redacted]	[redacted] [redacted]	[redacted] [redacted] [redacted] [redacted] [redacted]

		[redacted]
[redacted]	[redacted] [redacted] [redacted]	[redacted]

APPENDIX G

NOTIFICATION LEVELS

Position Classification	Income Change	Notify
[redacted]	[redacted] [redacted] [redacted]	[redacted] [redacted] [redacted] [redacted] [redacted]
[redacted]	[redacted] [redacted]	[redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted]

APPENDIX G

NOTIFICATION LEVELS

Position Classification	Value-at-Risk	Notify
[redacted]	[redacted]	[redacted] [redacted] [redacted] [redacted] [redacted] [redacted] [redacted]

<u>NOTE: Recipients of notification events will only receive detailed information pertinent to their business needs, and any correspondence will be in compliance with the Separation Protocol.</u>

APPENDIX G

NOTIFICATION LEVELS

Position Classification	Income Change	Notify
[redacted]	[redacted] [redacted]	[redacted]
[redacted]	[redacted] [redacted]	[redacted]

Position Classification	Value-at-Risk	Notify
[redacted]	[redacted]	[redacted]

APPENDIX H

MARKET RISK LIMITS

Net Open Position Limits

		[redacted]
[redacted]		[redacted]
[redacted]		[redacted]

[redacted]

[redacted]

APPENDIX I

INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Incumbent Listing

Name	Title
David Ratcliffe	Chairman, President, and Chief Executive Officer Southern Company
Paul Bowers	Chief Financial Officer, Southern Company Chairman, Southern Risk Oversight Committee Chairman, Risk Advisory and Controls Committee
Tom Fanning	Chief Operating Officer, Southern Company
Scott Teel	Chief Financial Officer, Southern Company Generation
Jerry Stewart	Chief Production Officer, Southern Company Generation
Wayne Moore	Chairman, Generation Risk Oversight Committee
Ron Hinson	Senior Vice President, Comptroller, and Chief Accounting Officer of SC
Ronnie Bates	President, Southern Power Company
Norrie McKenzie	Chief Commercial Officer, Southern Power Company
Mike Southern	Chief Financial Officer, Southern Power Company Chairman, Southern Power Risk Oversight Committee
Jeff Wallace	Vice President, Fuel Services
Charley Long	Vice President, Fleet Operations and Trading
Jon Haygood	Manager, Risk Control
Mike Bush	Manager, Energy Trading
Joe Styslinger	Manager, Southern Power Trading & Asset Management
Rob Hardman	Coal Services Director
Carl Haga	Gas Services Director
Roy Hiller	Gas Operations Manager

Southern Company Risk Oversight Committee

Name	Title
Paul Bowers (Chairman)	CFO & CRO, Southern Company
David Ratcliffe	Chairman, President, and CEO, Southern Company
Alan Martin	EVP, President & CEO, SCS
Tom Fanning	EVP & COO, SCS
Charles McCrary	EVP, Southern Company & President & CEO, APC
Mike Garrett	EVP, Southern Company & President & CEO, GPC
Ed Holland	EVP, General Counsel, and Corporate Secretary, Southern Company
Ronnie Labrato	EVP, Finance & Treasurer – non-voting member
Mark Lantrip	VP, Finance & Treasurer – non-voting member

APPENDIX I

INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Southern Company Risk Advisory & Controls Committee

Name	Title
Paul Bowers (Chairman)	CFO & CRO, Southern Company
Art Beattie	CFO, APC
Ronnie Labrato	CFO, GPC
Phil Raymond	CFO, Gulf Power Company
Francis Turnage	CFO, MPC
Scott Teel	CFO, SCG
Mike Southern	CFO, SPC
Mike Harreld	CFO, SoCo Transmission
Ron Hinson	Comptroller, CAO, & SVP, SCS
Mark Lantrip	VP Finance & Treasurer, SCS
Melissa Caen	VP & Associate General Council, SCS

Southern Company Generation Risk Oversight Committee

Name	Title
Wayne Moore (Chairman)	Regulatory Affairs & Energy Policy Director, SCS
Ed Day	EVP of E&CS, SCG
Jerry Stewart	Chief Production Officer, SCG
Dan McCrary	Legal Counsel, Balch & Bingham

Scott Teel	CFO, SCG
Todd Perkins	Enterprise Risk Management Director
Myrk Harkins	Internal Auditing Director

Southern Power Risk Oversight Committee

Name	Title
Mike Southern (Chairman	CFO, SPC
Wayne Moore	Regulatory Affairs & Energy Policy Director, SCS
Norrie McKenzie	Chief Commercial Officer, SPC
Todd Perkins	Enterprise Risk Management Director
Susan Comensky	Compliance & Corporate Affairs Director, SPC

APPENDIX I

INCUMBENT LISTING; AUTHORIZED INDIVIDUALS

Southern Company Generation Energy Credit Committee

Name	Title
Earl Long (Chairman)	Assistant Treasurer, SCS
Jeff Wallace	VP, Fuel Services
Charley Long	VP, Fleet Operations & Trading, SCG
Todd Perkins	Enterprise Risk Management Director

Fleet Operations & Trading Management Team

Name	Title
Scott Teel	Chief Financial Officer, SCG
Charley Long	VP, Fleet Operations & Trading, SCG
Brian Fuller	Manager, Energy Trading
Greg Darnell	Fleet Operations Manager

SCS Fuel Services Management Team

Name	Title
Jerry Stewart	Chief Production Officer, SCG
Jeff Wallace	VP, Fuel Services
Rob Hardman	Coal Services Director
Carl Haga	Gas Services Director

APPENDIX I

INCUMBENT LISTING; AUTHORIZED INDIVIDUALS (continued)

Authorized Individuals

		Approved Commodities								
		Electricity		Natural Gas			Coal	Oil	Allow-ances	RECs
Title	Name	Energy	Trans.	Gas	Trans-port	Storage				
Southern Company Generation										
Energy Term Trading Mgr.	Bill Norton	X	X	(2)			(2)	(2)	(2)	(2)
Term Trader	David Hansen	X	X	(2)			(2)	(2)	(2)	(2)
Term Trader	Tony Ankar	X	X	(2)			(2)	(2)	(2)	(2)
Term Trader	Stephen Stepkoski	X	X	(2)			(2)	(2)	(2)	(2)
Term Trader	Matt Ansley	X	X							
Trading Operations Mgr.	Corey Sellers	(1)	(1)							
Hourly Trading Mgr.	Steve Lowe	X	X							
Energy Coordinator	Bill Brown	X	X							
Energy Coordinator	Todd Curl	X	X							
Energy Coordinator	Frank Harris	X	X							
Energy Coordinator	Larry Savage	X	X							

Energy Coordinator	Karen Howland	X	X							
Energy Coordinator	Jimmy Walker	X	X							
Energy Coordinator	Shannon Gunnells	X	X							
Energy Coordinator	Michael Turberville	X	X							
Scheduler	Matt Bauman	(1)	X							
Scheduler	Stacey Pruitt	(1)	X							
Scheduler	Blair Ellington	(1)	X							
Trading Analyst	Jarrett Tate	(1)	(1)							
Trading Analyst	Martha Russell	(1)	(1)							
Trading Analyst	Susan Olive	(1)	(1)							

Notes:

(1) Authority to make changes to transactions including entering transactions related to loss adjustments and full/partial requirements customers.

(2) Authority to direct a transaction.

APPENDIX I

INCUMBENT LISTING; AUTHORIZED INDIVIDUALS (continued)

Authorized Individuals

		Approved Commodities								
		Electricity		Natural Gas			Coal	Oil	Allow-ances	RECs
Title	Name	Energy	Trans.	Gas	Trans-port	Storage				
SCS Fuel Services										
Gas Services, Director	Carl Haga			X	X	X				
Gas Operations Mgr.	Roy Hiller			X	X	X				
NG Buyer - Physical	Karen Gandy				X	X				
NG Buyer - Physical	Vicki Gaston			X	X	X				
NG Buyer - Physical	Debora Honeycutt			X	X	X				
NG Buyer - Financial	Paul Hughes			X						
NG Buyer - Financial	Tonya Gary			X	X	X				
NG Buyer - Financial	Beth Santoro			X						
NG Scheduler	Cherie McDaniel			X	X	X				
NG Scheduler	John Benefield			X	X	X				
NG Scheduler	Tisha Dale				X	X				
NG Scheduler	Russ Hall				X	X				
NG Scheduler	Billie Williams				X	X				

NG Buyer - Physical; NG Buyer - Financial	Carol Thomasson			X	X	X				
Coal & Transport Procure Manager	Debra Rouse						X			
Manager - Emissions	Ashley Robinett								X	X

		Approved Commodities								
		Electricity		Natural Gas			Coal	Oil	Allow-ances	RECs
Title	Name	Energy	Trans.	Gas	Trans-port	Storage				
Southern Power										
Manager - Trading & Asset Management	Joe Styslinger	X		(2)			(2)	(2)	(2)	(2)
Asset Manager	Tracy Ellis	X		(2)			(2)	(2)	(2)	(2)
Project Manager	Kenneth Wills	X		(2)			(2)	(2)	(2)	(2)
Term Trader	Scott Morales	X		(2)			(2)	(2)	(2)	(2)
Term Trader	John Spratley	X		(2)			(2)	(2)	(2)	(2)

Notes:

(1) Authority to make changes to transactions including entering transactions related to loss adjustments and full/partial requirements customers.

(2) Authority to direct a transaction.

APPENDIX J

ACCOUNTING AND TAX

FAS 133, Accounting for Derivative Instruments and Hedging Activities, and related guidance provides guidance for exchange-traded contracts and is the primary pronouncement addressing hedge accounting. Under FAS 133 all contracts meeting the definition of a derivative must be marked to market at the end of each accounting period with a gain or loss recorded in earnings, unless a qualifying hedge exists. FAS 133 defines two types of hedges that may be utilized: fair value hedges and cash flow hedges. In a fair value hedge, a derivative instrument is designated as hedging exposure to changes in the fair value of an asset, liability, or firm commitment. Changes in the fair value of the derivative and changes in the fair value of the hedged item attributable to the risk being hedged are recorded in earnings. If the hedge is 100-percent effective these changes in fair value will completely offset and there will be no effect on earnings. For cash flow hedges, changes in the fair value of the derivative are deferred as a component of equity on the balance sheet and then recognized in earnings in the same period as the effects of the hedged item.

A major condition required to account for a derivative as a hedge is that both at inception and on an ongoing basis the hedging relationship must be expected to be highly effective. [redacted]

APPENDIX K

EMPLOYEE ACKNOWLEDGMENT

I have been provided a copy of the Southern Company Energy Trading Risk Management Policy (RMP) and have had an opportunity to read and familiarize myself with its contents and understand the requirements that apply to my position.

I understand that the officers and Board of Directors of SCS place a very high priority on each employee adhering to the requirements, policies, and procedures described in the RMP and on the accurate tracking and reporting of levels and types of risks as described in the RMP.

I agree to comply with the policies, requirements, and procedures of the RMP as all or portions of the RMP apply to my position. I do not have any questions regarding or need to clarify any matters contained in the RMP.

____

Printed Name

____

Signature

Date: ____________________ _____, 200_

APPENDIX L

DEFINITIONS

Allowances	The right to emit chemical compounds such as sulfur dioxide usually traded in the over-the-counter markets via brokers with one allowance being equal to one ton of the pollutant (expressed in US short tons.) For Sulfur Dioxide (SO2) see the 1990 Clean Air Act Amendments, Title IV Section 402(3) "an authorization allocated to an affected unit by the Administator, to emit, during or after a specified calendar year one ton of sulfur dioxide. For NOx, the right to emit one ton of Nitrous Oxide during the 5 months ozone season May through September (beginning May 1st, 2003) as per the Final EPA Regional SIP Call Rules 40 CFR Parts 51, 72, 75 and 96. For trading in Green House Gases (predominately CO2) one ton of carbon dioxide emitted on an annual basis.
Approved Commodity	Those commodities listed in Appendix B which have been approved.
Authorities	All applicable limitations imposed on SCG RMP trading activities, and shall include, but not necessarily be limited to, authorized trading limits, daily loss exposure limits, maximum approved value at risk, income limits, and term limits

Authorized Individuals	Employees whose position may involve: (1) the authority (or appearance of authority) to directly bind SCS (or any subsidiary) to agreements with third parties; and/or (2) the authority (or appearance of authority), acting through its various brokers and other representatives, to bind SCS (or any subsidiary) to exchange-traded futures and option contracts.
Authorized Trading Limit	The levels set out in Appendix H. Such levels are expressed in dollars that establish boundaries for maximum value at risk due to changes in market prices.
Daily Portfolio Value	The net present value on a MTM basis of yet to be performed transactions from all approved portfolios.
Financial Instruments	Futures, forwards, options, swaps, and other derivative or financial risk management transactions entered into to hedge price risks.
Forwards	An agreement to buy or sell a quantity of a product, at an agreed price, on a given date, with a specific counterparty. Forwards are typically trading in the over-the-counter (OTC) markets.
Futures	An agreement to buy or sell a quantity of a product, at an agreed price, on a given date, traded on an exchange, and

	cleared by a clearinghouse.
Hedging Strategy	A trading strategy intended to reduce risk.
Liquid Market	A market characterized by wide bid/offer spreads, lack of transparency, and large movements in price after any sizable deal.
Mark to Market (MTM)	The value of a financial instrument, or risk book of such instruments, at current market rates, or prices of the underlying commodity.
Net Open Position	The sum of all open positions for the approved commodities on an equivalent basis.
Open Position	The difference between long positions and short positions in any given risk book.
Option	An instrument which provides the holder the right, but not the obligation, to sell to (or buy from) the option seller the underlying commodity at a specified price and time.
Originator	The lead individual responsible for negotiating the transaction with the counterparty.

Premises	Southern Company Generation business office located in Birmingham, Alabama
Products	Financial instruments and related transactions for approved commodities as dictated by usage.
Risk book	The official record in which details of all transactions are maintained for valuing, monitoring, managing, and reporting said risk
RMP	Risk Management Policy
SCS	Southern Company Services, Inc.
Swaps	An agreement to exchange net future cash flows.
Structured Transaction	Any negotiated transaction not readily traded in the market and the price of which is not easily validated.
Transactions	Futures, forwards, options, swaps, or other instruments conducted over-the-counter or via organized exchanges including long- and short-term agreements involving approved commodities or financial instruments.

Value at Risk (VaR)	The expected loss that will be incurred on the portfolio with a given level of confidence over a specified holding period, based on the distribution of price changes over a given historical observation period. (This is not an estimate of worst possible loss.)

Risk Management for Fuel and Wholesale Energy