Marguerite McLean

090001-EI

From: John W.McWhirter [jmcwhirter@mac-law.com]

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Cc: Allan Jungels; Bill McNulty; Billy Stiles; Burnett, John ; Cecilia Bradley; Charles Beck; Earl Poucher; G. G. Living; Jay Brew; 'Jeffrey Stone'; Jim Beasley; 'Joe McGlothlin'; 'John Butler '; 'John Office McWhirter '; 'Jon Moyle'; 'JR Kelly'; Karin S. Torain; Keino Young; Kory Dubin; Lisa Bennett; McNeill Shayla ; 'Mike Twomey'; Natalie Smith; Norman H. Horton; Patty Christensen, Esq.; Paula K Brown; Pete Lester; Charles Rehwinkel; Russell Badders, Esq.; Schef Wright; Susan D. Ritenour ; Timothy Perry, Esq.; Wade Litchfield; White Lt Col Karen

Subject: FIPUG post hearing brief docket 090001-EI

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1. John W. McWhirter, Jr., 400 N. Tampa St. Tampa, Fl 33602, jmcwhirter@mac-law.com is the person responsible for this electronic filing;
2. The filing is to be made in Docket 090001-EI, In re: Fuel Cost Recovery
3. The filing is made on behalf of the Florida Industrial Power Users Group;
4. The total number of pages is 13 and
5. The attached document is The Florida Industrial Power User Group's Post Hearing Statement of Issues, Positions and Brief

John W. McWhirter, Jr.

PO Box 3350

Tampa, Fl 33601-3350
813 2240866
813.505.8055 cell
813.221.1854 FAX

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.
______________________________/

Docket No. 090001-EI
Filed: November 12, 2009

FLORIDA INDUSTRIAL POWER USERS GROUP (FIPUG's) POST HEARING STATEMENT OF ISSUES AND POSTITIONS, CONCLUSIONS OF LAW AND BRIEF

STATEMENT OF THE CASE

In compliance with ORDER NO.PSC-09-0720-PHO-EI, Commission rule 28-06.215, and the November 2, 2009 ruling from the bench FIPUG files this pleading.

STATEMENT OF FACTS

To understand the issues in this brief it is necessary to have a basic knowledge of the corporate structure within which Gulf Power Company operates, the regulatory oversight that is in place and a general knowledge of its operations. For the first two items and part of the third the Commission is requested to take official notice of undisputed facts that are in the public domain and facts that are not subject to dispute because they are capable of accurate and ready determination by resort to sources whose accuracy cannot be questioned, such as, orders and filings by Gulf in official the official records of this Commission. This official notice is permitted by §90.202 (11) and (12) *Florida Statutes,* the evidence code.

Corporate Organizational Structure. According to its published history (http://www.gulfpower.com/about/history.asp) Gulf Power is a wholly owned Florida subsidiary of Southern Company, formerly known as Southeastern Power & Light Company, a Public Utility Holding Company. Southern and its subsidiaries own power plants in Alabama, Georgia, Mississippi and Florida.

Regulatory Oversight. Southern is registered with the US Securities and Exchange Commission for the sale of securities and other investor protections provided by the Securities and

Exchange Act of 1933. Its operations are also monitored and regulated by the Federal Energy Regulatory Commission with respect to mergers, wholesale tariffs, transmission access and other activities between Southern and third parties.

Gulf is regulated with respect to the charges it imposes upon retail customers by the Florida Public Service Commission (FPSC or Commission). This agency alone has jurisdiction to determine the charges that Gulf can impose upon retail customers. For the protection of consumers the FPSC has a rule that governs transactions between affiliated companies, FAC 25-6.1351 which is attached as an appendix to this brief. The FPSC was given authority to set retail rates in 1951 (§366.01 *Florida Statutes*) which says;

> The. commission shall have the authority to determine and fix fair, just, and reasonable rates that may be requested, demanded, charged, or collected by any public utility for its service.

From the inception of electric companies until the enactment of § 366.04(2) (d) & (e) *Florida Statutes*. in 1974. Florida electric utilities were able to compete with one another for retail customers. Since that date cogeneration is the only competitive supply resource available to Gulf's retail customers. For all intents and purposes Gulf is a monopoly providing service to captive customers. This circumstance gives rise to the need for FPSC regulatory oversight.

Operational Characteristics System Capacity. From 1926 to 1945 all of the power came to Gulf from Southern (Gulf Power.com, supra). After 1945 Gulf began to build power plants in Florida and elsewhere as its retail load grew. Gulf now owns 2511 megawatts of summer capacity[1]. 1423 MW located in Florida was built before 1974. It is composed of 1379 MW of coal burning and 32 MWs of light oil burning combustion turbines. Gulf plans to continue to operate most of this capacity until at least 2032. Gulf added 12 MWs of natural gas combustion turbine capacity in 1998 and a 556 MW

[1] (Gulf 10 Year site plan Schedule 1 Docket 090000-OT)

combined cycle natural gas plant in 2002 to its Florida generation. It now has 1991 MW of capacity located in Florida.

In addition to the Florida based capacity the Florida Commission authorized Gulf to add 513 MW of coal burning capacity located in Mississippi to the Florida retail rate base. (Orders 7978, 8424, and 10963 in Dockets 760858-EU and 81-0136-EU). This is not a free standing power plant, but an undivided interest in a power plant owned by Mississippi Power, an affiliated company under the aegis of Southern.

In 1989 Gulf attempted to expand its rate base further by adding another 219 MWs located outside of Florida. This capacity is a one third undivided interest Gulf Power owns in the Scherer coal burning power plant along with another Southern affiliate, Georgia Power. The Scherer plant is located near Macon, Georgia. The FPSC declined to allow Gulf to add the Scherer Plant to the rate base used to set rates for Florida customers. The rate base addition and all operating costs of the Scherer plant were excluded by the FPSC because the capacity of this plant was in the process of being sold to other utilities and would not be available for the benefit of Florida consumers until May 2010. (Order 23573 Docket 891345-EI) For purposes of this proceeding the operations of Scherer are irrelevant, but the addition of its lower fuel cost is somewhat misleading because it causes the system average fuel cost to appear to be less than it actually is.

Operational Characteristics - Electricity Interchange. In 2008 Gulf estimated that it could produce 17.5 million Mwh from its system generation.[2] When the Scherer sales are excluded [3] Gulf's ability to produce power from rate based generation drops to 16.2 million Mwh. In 2008 Gulf had to produce 12.2 million Mwh, before company use and line losses, to meet Florida retail customers 2008 needs for 11.5 million Mwh at the meter. It appears that Gulf could meet its obligations to retail customers from its own rate based generation with 4 million Mwh to spare (32%). The evidence shows that Gulf

[2] (Exhibit 134 line 1)
[3] (Exhibit 134 line 16)

supplemented this available electricity with 1.7 million Mwh from Southern and other utilities to bring the excess power over retail customer needs to 41%

It benefits retail customers if Gulf can displace system generation with electricity purchased less expensively than the cost of fuel to operate system generation. (the purchase criteria). It also benefits retail customers for Gulf to produce excess electricity if the extra energy can be sold for more than the cost of fuel (the sale criteria).

In 2008 Gulf bought 754 thousand Mwh from Southern along with 980 thousand Mwh from other sources to meet its electric supply commitments. Exhibit 134 pages 2 and 3 provide the information needed to see if electricity interchange transactions met purchase criteria for benefitting retail customers. Schedule A-9 for 2008 set out on page 2 of Exhibit 134 shows on lines 7 and 10 that purchases from Non-Associated Companies at $30.90 / Mwh and $0.80 per Mwh for "other transactions". These prices are less than system average fuel cost of $43.93/ Mwh. They clearly met the criteria for prudent purchases.

Transactions With Southern
ELECTRICTY PURCHASES

Year	Energy Payment	Capacity Payment	MWH Purchased	Avg. Fuel cost $ / Mwh from native generation	Fuel cost electricity purchased from Southern	Total $/ MWH paid Southern	$/Mwh Retail Subsidy requested
2008	$36,850,419	$28,532,144	754,573,	$43.93	48.84	86.65	$42.72
2009	$32,717,596	$10,601,500	777,425	$45.99	42.01	$55.72	$9.73
2010	$28,916,000	$9,426,009	742,629	$48.52	38.94	$51.73	$3.11

The payments to Southern Company of $48.84/ Mwh for the fuel component plus $37.81 / Mwh for capacity drives the price for purchases from Southern to $86.65 /Mwh this price woefully fails the prudent purchase test. Gulf paid Southern $32,234,171 more for electricity than it would have cost to produce the energy from its own resources. Without an explanation of the benefits customers received from these purchases they are patently imprudent.

The next criteria for judging customer benefits from interchange transactions deals with Gulf's sales of its excess power. These sales for 2008 are summarized on page 1 lines and 14 through 17 of Exhibit 134 and detailed on page 3. Sales to non associated utilities resulted in payments of $63.26 per Mwh for energy plus $1.2 million in capacity payments from these companies (lines 14 & 15). These sales qualify as beneficial because they resulted in fuel cost reductions to retail customers of $3.8 million more than the cost to produce the electricity sold.

Unit power sales on line 16 of the exhibit are sales from the Scherer plant are irrelevant because the revenue receipts on line 16 of Schedule A-1 do no more than off set the fuel cost included on line 1 of the schedule.

Sales to the Southern Company are shown on line 17. Without further evidence these sales are not beneficial to retail customers because the $36.05 per Mwh in revenue received for the sales is $7.88 less per Mwh than the fuel cost to produce the electricity. These sales resulted in a resulted in payments to Southern of $19.7 million more than it would cost to generate the power internally. Retail customers would have been better off if the fuel hadn't been burned. These sales to Southern appear to be imprudent unless Gulf can demonstrate a retail customer benefit.

The 2009 fuel costs to date indicate that burned fuel cost less this year, but fuel price hedging will result in keeping fuel price relatively steady for retail customers. The 2009 average fuel cost for retail customers without plant Scherer costs is expected to be $45.99. For 2010 as originally filed, excluding Plant Scherer (but including the new PPA energy savings before capacity charges) fuel costs are expected to rise to $48.52. When the average fuel cost to retail customers is compared to transactions with Southern the prices that should be evaluated under the affiliate transactions rule are developed in the table below.

Transactions With Southern

ELECTRICTY SALES

Year	Energy Payment	Capacity Payment	MWH Sold	Average fuel cost to generate power	Revenue/ MWH from Southern	Revenue shortfall per Mwh for Southern	Apparent total Southern revenue shortfall
2008	$90,358,419	0	2,506,542[4]	$43.93	$36.05	$7.88	$19,751,551
2009	$54,836,797	0	1,909,596	$45.99	$28.72	$17.27	$32,978,723
2010	$55,790,000	0	1,365,947	$48.52	$40.84	$7.68	$10,490,473

From the evidence in the record Gulf appears to pay more to buy electricity from Southern than it costs to generate the electricity from its own resources. It charges Southern less for the energy it sells to Southern because Southern receives no cost allocation for Gulf's financial hedging losses and further for some unexplained reason Gulf sells much more power to Southern with no capacity cost allocation.

SUMMARY OF ARGUMENT

In its discussion of the issues FIPUG will contend that it is not just and reasonable for retail customers to pay Southern far more to buy electricity than it would cost to provide the electricity

[4] Schedule A-6 line 6, page 3 of Exhibit 134 shows that Southern paid $106,988, 751or $57.20 for the electricity it purchased from Gulf, but the payments are reduced by $12,173.793 on line 64 for "Flow –Thru Energy" and the kwh are adjusted on lines 66 & 69. The summary of the calculations shown on line 17 Schedule A-1 page one of exhibit 134.

from its own generation sources. It will argue that retail customers would be better off if Gulf didn't sell electricity to Southern for less than the fuel cost to produce it. Paying Southern capacity costs of $48.6 million over a 3 year period to reserve capacity without explanation of why it is needed to comply with the Commission's reserve capacity rule is imprudent. It is unfair to charge retail customers hedging costs to maintain fuel price stability and then when fuel costs fall below forecasts to sell the low cost fuel generated electricity to Southern without any allocation of this cost of doing business as required by Rule 25-6.1351 F.A.C. FIPUG questions why Gulf pays Southern $48.6 million in capacity costs for the 2.3 million Mwh of electricity it has purchased or will purchase from Southern, but charges little or nothing for the 5.8 million Mwh it has sold or will sell to Southern.

ISSUES IN DISPUTE

ISSUE 8: What are the appropriate fuel adjustment true-up amounts for the period January

FIPUG: *Gulf claims an under recovery of $48,757,977. It has failed to justify $19,751,551 subsidy to Southern; $3,702 payments more than the fuel cost of self generation or $28,532,144 to reserve capacity from Southern. The appropriate adjustment for 2008 after removing subsidies to Southern should be an over recovery of $3,227,745*

ISSUE 9: What are the appropriate fuel adjustment true-up amounts for the period January 2009 through December 2009?

FIPUG: *Gulf estimates that in 2009 it will have an over recovery of $36,414,908. FIPUG claims that Southern subsidies should be removed. This will increase the over recovery to $76,958,951.*

ISSUE 10: What are the appropriate total fuel adjustment true-up amounts to be collected/refunded from January 2010 to December 2010?*

FIPUG: *Gulf should refund $92,529,765.*

ISSUE 12: What are the appropriate projected net fuel and purchased power cost recovery and Generating Performance Incentive amounts to be included in the recovery factor for the period January 2010 through December 2010?

FIPUG: *Gulf $ $575,037,124 *

ISSUE 13: What are the appropriate levelized fuel cost recovery factors for the period January 2010 through December 2010?

FIPUG: *For Gulf, the 2010 fuel cost factor should be 4.2966 cents per kwh.*

ISSUE 15: What are the appropriate fuel cost recovery factors for each rate class/delivery voltage level class adjusted for line losses?

FIPUG: *See table below:

Group	Rate Schedules*	Line Loss Multipliers	Fuel Cost Factors ¢/KWH		
			Standard	Time of Use	
				On-Peak	Off-Peak
A	RS, RSVP,GS, GSD, GSDT, GSTOU, OSIII, SBS(1)	1.00526	4.3129	4.7153	4.0096
B	LP, LPT, SBS(2)	0.98890	4.2489	4.6449	3.9501
C	PX, PXT, RTP, SBS(3)	0.98063	4.2134	4.6071	3.9177
D	OSI/II	1.00529	No Position	N/A	N/A

DISCUSSION OF ISSUES

2008 was chosen as the best year to examine the Gulf fuel filing because it is the only year for which actual numbers are supplied. An examination of the numbers for that year makes the final adjustments and that don't appear in the forecasted projections for 2009. It is the best year to review to see if the affiliated transaction purchases from Southern and sales to Southern benefit retail customers.

FIPUG acknowledges that the best criteria for determining whether Gulf had adequate company owned capacity to meet a reasonable reserve margin for its customers should be based on summer peak demand not a review of the excess sales, but that information is not in this record nor was any other effort made by Gulf to justify the need to buy reserve capacity while contemporaneously making sales to Southern with no capacity component. Mr. Ball says the Commission staff audited the transactions, but the audit was not filed. He says that marginal costs from the least costly plant 24 hours a day resulted in the lower prices to Southern, but that is like an allegation in a pleading. It is a conclusion that must be proved in an administrative public hearing not in a Star Chamber discussion with a staff member or filed away in case a Commission staff member might want to see it. Millions of dollars are at stake. Gulf has a duty to demonstrate to customers in an open hearing that its transactions with the big guys in Atlanta are beneficial to customers. The only evidence in the record shows that the transactions are detrimental to Gulf's customers in a major way.

Some may think that with the watchdogs at the SEC and FERC on the job monitoring Southern retail consumers are safe from potential overreaching, but those watch dogs are barking up another tree.

The FPSC has laid the ground work for consumer protection in the affiliated transaction rule. It has the principal authority to protect Florida rate payers. Section 3c of the FPSC affiliated transaction rule allows Southern to impose additional costs on Gulf to recover its fully allocated costs, but it only permits this if the power is needed by Gulf. The heart of the rule is contained in the first paragraph which says:

> (1) Purpose. ***The purpose of this rule is to establish cost allocation requirements to ensure proper accounting for affiliate transactions and utility nonregulated activities so that these transactions and activities are not subsidized by utility ratepayers***.

Respectfully submitted
s/ ***John W McWhirter, Jr.***

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing pleading was furnished to the following, by electronic mail, on this 12th day of November, 2009:

Lisa C. Bennett Senior Attorney FLORIDA PUBLIC SERVICE COMMISSION Gerald L. Gunter Building 2540 Shumard Oak Boulevard Tallahassee, Fl 323	Paula K. Brown Tampa Electric Company P. O. Box 111 Tampa, Florida 33601-0111
Paul Lewis, Jr. Progress Energy Florida, Inc. 106 East College Avenue, Suite 800 Tallahassee, FL 32301-7740	Lee L. Willis/James D Beasley. Ausley Law Firm Box 391 Tallahassee, FL 32301
Office of Public Counsel J.R. Kelly/C. Rehwinkel/P. Christensen c/o The Florida Legislature 111 W. Madison Street, Room 812 Tallahassee, FL 32399-1400	R. Wade Litchfield & John T. Butler Florida Power & Light Company 700 Universe Boulevard Juno Beach FL 33408-0420
Jay W. Brew Brickfield, Burchette, Ritts & Stone, P.C. 1025 Thomas Jefferson St., NW Eighth Floor, West Tower Washington, DC 20007-5201	Beggs & Lane Law Firm J. Stone/R. Badders/ S. Griffin Post Office Box 12950 Pensacola, FL 32591
Susan D. Ritenour Gulf Power Company One Energy Place Pensacola, FL 32520-0780	John T. Burnett / R. Alexander Glenn Progress Energy Service Company, LLCPost Office Box 14042 St. Petersburg, FL 33733-14042
Robert Scheffel Wright/John T. LaVia 225 South Adams Street, Suite 200 Tallahassee, FL 32301	Capt Shayla L McNeill, USAF, Capt Al Jungals Staff Attorneys AFLOA/JACL-ULT 139 Barnes Drive Tyndall AFB, FL 32403-5317
Florida Retail Federation John Rogers 100 East Jefferson Street Tallahassee, FL 32301	/s/ *John W. McWhirter, Jr.* John W. McWhirter, Jr PO Box 3350 Tampa, Fl 33601 813.505.8055

APPENDIX 1

25-6.1351 Cost Allocation and Affiliate Transactions.

(1) Purpose. ***The purpose of this rule is to establish cost allocation requirements to ensure proper accounting for affiliate transactions and utility nonregulated activities so that these transactions and activities are not subsidized by utility ratepayers.*** This rule is not applicable to affiliate transactions for purchase of fuel and related transportation services that are subject to Commission review and approval in cost recovery proceedings. (emphasis supplied)

(2) Definitions.

(a) Affiliate – Any entity that directly or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with a utility. As used herein, "control" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a company, whether such power is exercised through one or more intermediary companies, or alone, or in conjunction with, or pursuant to an agreement, and whether such power is established through a majority or minority ownership or voting of securities, common directors, officers or stockholders, voting trusts, holding trusts, associated companies, contracts or any other direct or indirect means.

(b) Affiliate Transaction – Any transaction in which both a utility and an affiliate are each participants, except transactions related solely to the filing of consolidated tax returns.

(c) Cost Allocation Manual (CAM) – The manual that sets out a utility's cost allocation policies and related procedures.

(d) Direct Costs – Costs that can be specifically identified with a particular service or product.

(e) ***Fully Allocated Costs – The sum of direct costs plus a fair and reasonable share of indirect costs. (emp. supp.)***

(f) Indirect Costs – Costs, including all overheads, that cannot be identified with a particular service or product.

(g) Nonregulated – Refers to services or products that are not subject to price regulation by the Commission or not included for ratemaking purposes and not reported in surveillance.

(h) Prevailing Price Valuation – Refers to the price an affiliate charges a regulated utility for products and services, which equates to that charged by the affiliate to third parties. To qualify for this treatment, sales of a particular asset or service to third parties must encompass more than 50 percent of the total quantity of the product or service sold by the entity. The 50 percent threshold is applied on an asset-by-asset and service-by-service basis, rather than on a product line or service line basis.

(i) Regulated – Refers to services or products that are subject to price regulation by the Commission or included for ratemaking purposes and reported in surveillance.

(3) Non-Tariffed Affiliate Transactions.

(a) The purpose of subsection (3) is to establish requirements for non-tariffed affiliate transactions impacting regulated activities. This subsection does not apply to the allocation of costs for services between a utility and its parent company or between a utility and its regulated utility affiliates or to services received by a utility from an affiliate that exists solely to provide services to members of the utility's corporate family. ***All affiliate transactions, however, are subject to regulatory review and approval. (emp. supp.)***

(b) ***A utility must charge an affiliate the higher of fully allocated costs or market price for all non-tariffed services and products purchased by the affiliate from the utility. Except, a utility may charge an affiliate less than fully allocated costs or market price if the charge is above***

incremental cost. (emp. supp.)If a utility charges less than fully allocated costs or market price, the utility must maintain documentation to support and justify how doing so benefits regulated operations. If a utility charges less than market price, the utility must notify the Division of Economic Regulation in writing within 30 days of the utility initiating, or changing any of the terms or conditions, for the provision of a product or service. In the case of products or services currently being provided, a utility must notify the Division within 30 days of the rule's effective date.

(c) ***When a utility purchases services and products from an affiliate and applies the cost to regulated operations, the utility shall apportion to regulated operations the lesser of fully allocated costs or market price.(emp. Supp.)*** Except, a utility may apportion to regulated operations more than fully allocated costs if the charge is less than or equal to the market price. If a utility apportions to regulated operations more than fully allocated costs, the utility must maintain documentation to support and justify how doing so benefits regulated operations and would be based on prevailing price valuation.

(d) When an asset used in regulated operations is transferred from a utility to a nonregulated affiliate, the utility must charge the affiliate the greater of market price or net book value. Except, a utility may charge the affiliate either the market price or net book value if the utility maintains documentation to support and justify that such a transaction benefits regulated operations. When an asset to be used in regulated operations is transferred from a nonregulated affiliate to a utility, the utility must record the asset at the lower of market price or net book value. Except, a utility may record the asset at either market price or net book value if the utility maintains documentation to support and justify that such a transaction benefits regulated operations. An independent appraiser must verify the market value of a transferred asset with a net book value greater than $1,000,000. If a utility charges less than market price, the utility must notify the Division of Economic Regulation in writing within 30 days of the transfer.

(e) Each affiliate involved in affiliate transactions must maintain all underlying data concerning the affiliate transaction for at least three years after the affiliate transaction is complete. This paragraph does not relieve a regulated affiliate from maintaining records under otherwise applicable record retention requirements.

(4) Cost Allocation Principles.

(a) Utility accounting records must show whether each transaction involves a product or service that is regulated or nonregulated. A utility that identifies these transactions by the use of subaccounts meets the requirements of this paragraph.

(b) Direct costs shall be assigned to each non-tariffed service and product provided by the utility.

(c) Indirect costs shall be distributed to each non-tariffed service and product provided by the utility on a fully allocated cost basis. Except, a utility may distribute indirect costs on an incremental or market basis if the utility can demonstrate that its ratepayers will benefit. If a utility distributes indirect costs on less than a fully allocated basis, the utility must maintain documentation to support doing so.

(d) Each utility must maintain a listing of revenues and expenses for all non-tariffed products and services.

(5) Reporting Requirements. Each utility shall file information concerning its affiliates, affiliate transactions, and nonregulated activities on Form PSC/ECR/101 (3/04) which is incorporated by reference into Rule 25-6.135, F.A.C. Form PSC/ECR/101, entitled "Annual Report of Major Electric Utilities," may be obtained from the Commission's Division of Economic

Regulation.

(6) Cost Allocation Manual. Each utility involved in affiliate transactions or in nonregulated activities must maintain a Cost Allocation Manual (CAM). The CAM must be organized and indexed so that the information contained therein can be easily accessed.

Specific Authority 350.127(2), 366.05(1) FS. Law Implemented 350.115, 366.04(2)(a), (f), 366.041(1), 366.05(1), (2), (9), 366.06(1), 366.093(1) FS. History–New 12-27-94, Amended 12-11-00, 3-30-04