# Restatement of 1988 UPS Agreement
# between
# Southern Companies
# and
# Florida Power Corporation

# Southern Operating Companies
# Rate Schedule FERC No. 66

**Filed in compliance with**
**Federal Energy Regulatory Commission**
**Order No. 614**
**pursuant to letter order in Docket No. ER01-602,**
**dated January 24,2001**

**BALCH & BINGHAM LLP**

ATTORNEYS AND COUNSELORS
POST OFFICE BOX 306
BIRMINGHAM, ALABAMA 35201-0306
(205) 251-8100

Lyle D. Larson
RECT DIAL TELEPHONE:
(205) 226-3441
Email: llarson@balch.com

WRITER'S OFFICE:
1710 SIXTH AVENUE NORTH
BIRMINGHAM, ALABAMA 35203-2015
FACSIMILE (205) 226-8798

February 26,2001

**BY OVERNIGHT DELIVERY**
Mr. David P. Boergers, Secretary
Federal Energy Regulatory Commission
Office of the Secretary
888 First Street, N.E.
Washington, D.C. 20426

Re: Order No. 614 Compliant Tariff Sheets for Rate Schedules FERC Nos. 66, 67 and 68 in Docket No. ER01-602

Dear Mr. Boergers:

Enclosed for filing please find an original and six (6) copies of Order No. 614 compliant rate schedule sheets for Southern Operation Companies Rate Schedules FERC Nos. 66, 67 and 68 as required by the Commission Order of January 24,2001 in Docket No. ER01-602. These Order No. 614 compliant sheets are restatements of three 1988 Unit Power Sales ("UPS") Agreements between Southem Companies and Florida Power Corporation (No. 66), Florida Power & Light (No. 67), and Jacksonville Electric Authority (No. 68) consistent with Order No. 614, FERC Stats & Regs. ¶ 31,096 (2000), as amended over the years. Also enclosed are two (2) confirmation copies of each of the three (3) restated UPS Agreements. Please date stamp these and return them to us in the enclosed self-addressed Federal Express envelope provided herein.

If you have any questions about this filing, please contact either of the attorneys below

Sincerely yours,

Lyle D. Larson
Attorney for Southern Operating Companies

LDL/lt
Enclosures

**OF COUNSEL:**
Lyle D. Larson
Gregory P. Butrus
BALCH & BINGHAM LLP
Post Office Box 306
Birmingham, AL 35201
(205) 251-8100

BALCH & BINGHAM LLP
ATTORNEYS AND COUNSELORS
POST OFFICE BOX 306
BIRMINGHAM. ALABAMA 35201-0306
(205) 251-8100

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Gregory P. Butrus
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Post Office Box 306
Birmingham, AL 35201
(205) 251-8100

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southern Company Services, Inc. Docket No. ER01-602-000

NOTICE OF FILING

Take notice that on February 26, 2001, Southern Company Services, Inc., as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Savannah Electric and Power Company (collectively, Southern Companies), tendered for filing rate schedule sheets compliant with Commission Order No. 614 for Southern Operating Companies Rate Schedules FERC Nos. 66, 67, and 68 pursuant to the letter order in Docket No. ER01-602, dated January 24, 2001. The three Order No. 614 compliant rate schedules tendered for filing concern 1988 Unit Power Sales agreements between Southern Companies and Florida Power Corporation, Florida Power & Light, and Jacksonville Electric Authority.

Any person desiring to be heard or to protest such filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 C.F.R. §§ 385.211 and 385.214). **All** such petitions and protests should be filed on or before ______________, 2001. Protests will be considered by the Commission to determine the appropriate action to be taken, but will not serve to make protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

David P. Boergers,
Secretary

**UNIT POWER SALES AGREEMENT
BETWEEN
FLORIDA POWER CORPORATION
AND
ALABAMA POWER COMPANY,
GEORGIA POWER COMPANY,
GULF POWER COMPANY,
MISSISSIPPI POWER COMPANY,
SAVANNAH ELECTRIC AND POWER COMPANY
AND SOUTHERN COMPANY SERVICES, INC.**

THIS Unit Power Sales Agreement ("UPS Agreement"), made and entered into as of the 19th day of July, 1988, by and between FLORIDA POWER CORPORATION ("Corporation"), a Florida corporation, and ALABAMA POWER COMPANY ("APC"), an Alabama corporation, GEORGIA POWER COMPANY ("GaPC"), a Georgia corporation, GULF POWER COMPANY, ("GuPC"), a Maine corporation, MISSISSIPPI POWER COMPANY ("MPC"), a Mississippi corporation, and SAVANNAH ELECTRIC AND POWER COMPANY ("SEPCO"), a Georgia corporation (APC, GaPC, GuPC, MPC and SEPCO being sometimes collectively referred to as "Southern Companies") and SOUTHERN COMPANY SERVICES, INC. ("SCS"), an Alabama corporation.

W I T N E S S E T H:

WHEREAS, Southern Companies are all affiliates by virtue of the ownership of the common stock of such companies by The Southern Company, a registered public utility holding company under the Public Utility Holding Company Act of 1935; and

WHEREAS, APC, GaPC, GuPC and MPC, together with SCS and Corporation, are parties to an Interchange Contract dated December 15, 1968, as amended, ("Interchange Contract") which provides for certain points of interconnection between the parties, and, pursuant to the terms of which the parties have constructed and maintained points of interconnection which provide and improve system reliability of each of the systems and can accommodate transactions under this UPS Agreement as well as other agreements between the parties; and

WHEREAS, Corporation desires to purchase and APC, GaPC and GuPC desire to sell unit power capacity from designated coal-fired steam electric generating units of their J. H. Miller, Jr. Steam Electric Generating Plant ("Miller Plant") and Robert W. Scherer Steam Electric Generating Plant ("Scherer Plant") in designated amounts during the periods specified herein; and

WHEREAS, Southern Companies are joining in this UPS Agreement to provide, among other things, necessary transmission services, substitute capacity and energy in the event commercial operation of certain generating units of the Miller Plant is delayed or cancelled and supplemental energy when any designated unit of the Miller Plant or Scherer Plant is unavailable or derated; all as set forth herein.

NOW, THEREFORE, in consideration of the premises and the covenants and agreements of the parties hereinafter set forth, the parties hereto agree as follows:

ARTICLE I

TERM OF AGREEMENT

1.1 Term: This UPS Agreement shall become effective as of the date of the latest signature on the signature page hereof and shall continue in effect through May 31, 2010.

1.1.1 It is understood by the parties hereto that this UPS Agreement will be filed by Southern Companies with the Federal Energy Regulatory Commission ("FERC") or its successor in interest within sixty (60) days from the effective date hereof. Corporation agrees to cooperate and assist Southern Companies in securing conclusion of any initial review by FERC of this UPS Agreement without significant change, in an expeditious manner. It is further understood by the parties that timely FERC approval or acceptance of this UPS Agreement is important in order to facilitate capacity planning on the part of both Corporation and Southern Companies. Accordingly, if FERC has not approved or accepted for filing this UPS Agreement on or by June 1, 1989, the parties hereto agree that their representatives will meet to determine how to expedite the filing and review process.

ARTICLE II

UNIT POWER CAPACITY

2.1 Units from which Capacity Will be Made Available: Except as specifically provided for in this ARTICLE 11, the capacity entitlement will be made available from Units 1, 2, 3 and 4 of the Miller Plant located in Jefferson County, Alabama and Unit 3 of the Scherer Plant located in Monroe county, Georgia. Exhibit A, which is attached hereto and incorporated herein by reference, sets forth the projected date for commercial operation of each unit; and the amount of the Expected Capacity of each unit owned by APC, GaPC and GuPC which is made available for sale hereunder to Corporation.

2.2 Capacity to be Purchased and Sold: Subject only to adjustments as provided in this Article 11, APC, GaPC and GuPC hereby agree to sell and Corporation hereby agrees to purchase capacity entitlement from the units specified in 2.1

above, in the following aggregate amounts: (i) 200 megawatts ("MW") of unit power ("first 200 MW sale") during the period January 1, 1994 to May 31, 2010, which unit power will not be subject to cancellation or termination by any party to this UPS Agreement; and (ii) an additional 200 MW of unit power ("second 200 MW sale") during the period January 1, 1995 to May 31, 2010, which second 200 MW sale or any portion thereof, will be subject to termination by Corporation on or after January 1, 2000 (but in no event earlier) provided, that Corporation gives at least three (3) years advance written notice to APC, GaPC and GuPC that it desires to terminate the second 200 MW sale, or any portion thereof, on such date or thereafter. Exhibit A sets forth the amount of Expected Capacity to be purchased by Corporation and sold by APC, GaPC and GuPC from each designated unit of the Miller Plant and Scherer Plant during the above-specified periods assuming Corporation does not exercise its right to terminate the second 200 MW sale, or any portion thereof. In the event Corporation elects to terminate all or a portion of the second 200 MW sale on or after January 1, 2000, the remaining sale (not less than 200 MW) will be allocated equally among the units specified in Section 2.1 above. In the case of Unit 3 of the Scherer Plant, the remaining sale will be allocated on a basis of 2 MW out of GuPC's ownership portion of such unit to each 1 MW out of GaPC's ownership portion of such unit. For example, if the remaining sale is 200 MW, the sale to Corporation will be allocated as follows: 40 MW out of each of Units 1, 2, 3 and 4 of the Miller Plant: 27 MW out of GuPC's portion of Unit 3 of the Scherer Plant: and 13 MW out of GaPC's portion of Unit 3 of the Scherer Plant.

The parties hereto recognize that long-range plans and forecasts which provide the basis for such sales and purchases of capacity are affected by many factors. Therefore:

**2.2.1** In addition to the above rights and obligations, Corporation shall have the option to commence taking the full unit power sale (400 MW), or any part thereof, on a date as early as January 1, 1993, provided that advance written notice is given to Southern Companies at least twenty-four (24) months prior to such take ("early option"). Further, the parties hereto agree that the early option will not be applied to allow the total sales of unit power capacity in any month to be less than the total sale for any previous month during the period January 1, 1993 to January 1, 1995. It is the intent of the parties hereto that additional unit power sales under the early option to contemporaneous parties (as defined in Section 10.10) will be supplied in equal amounts from the four units of the Miller Plant and the one unit of the Scherer Plant: however, it is recognized that in some time periods there will not be sufficient unsold capacity in Unit 4 of the Miller Plant and/or Unit 3 of the Scherer Plant to meet the one-fifth (1/5) allocation from each unit of the early option to contemporaneous parties. During such time periods, the additional unit power sales will be supplied first from Unit 4 of the Miller Plant and/or Unit 3 of the Scherer Plant to the extent unsold (in no event more than one-fifth (1/5) of the early option) with the remainder supplied equally from Units 1, 2 and 3 of the Miller Plant. All sales from Unit 3 of the Scherer Plant will be allocated on the basis of 2 MW from GuPC's ownership in that unit to each 1 MW from GaPC's ownership in that unit to the extent capacity is unsold. Without regard to the timing of the notice to exercise this early option by Corporation and other contemporaneous parties, Corporation and other contemporaneous parties will be supplied additional unit power sales from the units specified in Section 2.1 in accordance with the foregoing principles and in proportion to the amount of unit power sales advanced by Corporation and each of the other contemporaneous parties. Due to the complicated nature of this early option, the parties hereto have agreed to examples of the operation of the early option under different assumptions and have attached such examples to this UPS Agreement as a part of Exhibit A. In the event of any disputes concerning the operation of the early option, the examples will govern.

2.2.2 Further, Corporation shall have the right to take Long Term Power as provided for in Exhibit B, which is attached hereto and incorporated herein by reference, in substitution for any unit power that corporation had a right to advance pursuant to the early option (set forth in Section 2.2.1). In no event, however, will Southern Companies, APC, GaPC, GUPC or Corporation be allowed to substitute Long Term Power for the first 200 MW sale or the second 200 MW sale or any unit power advanced under the early option.

**2.2.3** If, however, Southern Companies have an opportunity to sell unit power or Long Term Power during the period January 1, 1993 to January 1, 1995 to third party utilities, Southern Companies shall give notice to Corporation of such opportunity and Corporation will have sixty (60) days in which to exercise the early option as to that amount of capacity which Southern Companies has an opportunity to sell during the period. Any such unit power or Long Term Power offered to third parties will be offered to Corporation and other contemporaneous parties (on a pro rata basis) at equal or improved terms. In the event Corporation does not elect to exercise the early option (or purchase the newly-offered unit power capacity or Long Term Power) at the end of such sixty (60) day period, the early option shall expire as to such amount of capacity. However, such option shall not expire as to any amount of capacity under the early option which remains unsold. As to such remaining amount of capacity, each contemporaneous party shall retain the early option for its pro rata share of such amount of capacity based on a ratio of its full unit power sale to the sum of the full unit power sales of all contemporaneous parties. A contemporaneous party exercising an early option does not trigger the early option provision for the other contemporaneous parties. For purposes of this provision, capacity purchases in addition to those incorporated in the contracts with contemporaneous parties shall be treated as purchases by third parties.

Any opportunity of Southern Companies to sell capacity to third party utilities for the period January 1, 1993 to May 31, 1993 shall not cause Corporation's early option for the period June 1, 1993 to December 31, 1994 to expire as to such amount of capacity which Corporation, in its sole discretion, determines that it cannot take under the early option due to transmission limitations on its electric system.

*2.2.4* In the event that Southern Companies, prior to 1993, offer to sell unit power capacity from coal-fired generating resources during the period January 1, 1998 through May 31, 2010, to third party utilities located outside the geographical areas served by Southern Companies, Corporation and other contemporaneous parties shall each have the right of first refusal for the purchase of any part or all of its pro rata share of such capacity: provided, however, such right must be exercised within ninety (90) days after written notice from southern Companies informing Corporation of such capacity being made available for sale and the terms and conditions of each offer. Furthermore, in the event that Southern Companies, after 1992, offer to sell unit power capacity from coal-fired generating resources during the period June 1, 1995 through May 31, 2010 to third party utilities located outside the geographical areas served by Southern Companies Corporation and other contemporaneous parties shall each have the right of first refusal for the purchase of any part or all of its pro rata share of such capacity; provided, however, such right must be exercised within ninety (90) days after written notice from Southern Companies informing Corporation of such capacity being made available for sale and the terms and conditions of each offer. In the event Corporation exercises its rights under Section 2.2 to terminate any portion of the second 200 MW sale, all rights of first refusal set forth in this Section 2.2.4 shall immediately terminate and be void as of the date of the notice to Southern Companies from Corporation terminating all or any portion of the second 200 MW sale; however, Southern Companies shall inform Corporation of their intent to seek offers for additional sales of unit power capacity or Long Term Power. For purposes of this Section 2.2.4, pro rata share shall be computed as the ratio of Corporation's unit power purchases under this UPS Agreement to the total unit power purchases by all contemporaneous parties on June 1, 1995. Any contemporaneous party which exercises its rights to terminate under sections similar to Section 2.2 of this UPS Agreement shall be excluded from the calculation of pro rata share.

**2.2.5** In the event the rate for transmission charges (as such rate may be revised from time to time pursuant to Article III of the Unit Power Sale Manual incorporated by reference in Section 5.1 of this UPS Agreement) is rejected or modified by FERC, Southern Companies shall have the right, upon thirty (30) days written notice, to make a unilateral filing with FERC under Section 205 of the Federal Power Act, and Corporation shall have the right to file a complaint under Section 206 of the Federal Power Act, to amend Exhibit A to reallocate the capacity sales specified in Section 2.2 among all of the units specified in Section 2.1 so as to restore the economic positions of the parties hereto to that held prior to FERC's action. If corporation determines that it cannot, in good faith, support Southern Companies' filing for such reallocation, it may oppose the filing before FERC; but it shall limit any participation in any FERC proceeding concerning the reallocation of the unit power sales to questions of whether the reallocation correctly restores the economic position of the parties hereto.

**2.3** <u>Determination of Capacity Available from Each Unit</u>: The amount of capacity to be made available from each unit specified in Section 2.1 to constitute the total capacity to be sold by APC, GaPC and GuPC and purchased by Corporation hereunder, will vary from time to time during the term of this UPS Agreement. The nominal schedule of units, by time period, from which sales will be made is set forth in Exhibit A, such Exhibit A representing an agreed allocation to Corporation of capacity under this UPS Agreement from each of the units specified in Section 2.1 by time period based on Expected Capacity. It is recognized by the parties hereto and expressly provided for in Section 2.3.4 that the actual units from which sales will be made, and the total capacity to be sold and purchased? may vary from that set forth in Exhibit A and any such variance shall be based on the following principles:

**2.3.1** On or before September 15, 1992 and September 15 of each year thereafter during the term hereof, the Net Dependable Capacity will be established for each unit which has theretofore been declared available for commercial operation or which is expected to be declared available for commercial operation during the ensuing calendar year. Net Dependable Capacity for each unit shall be determined in accordance with the procedure specified in Article I of the Unit Power Sale Manual described in Section 5.1 hereof.

**2.3.2** If the Net Dependable Capacity established for a unit from which capacity is to be sold to Corporation during the ensuing year is equal to the Expected Capacity of such unit as set forth in Exhibit A, the amount of capacity scheduled to be furnished from such unit during the ensuing year shall be as specified in Exhibit A.

**2.3.3** **If** the Net Dependable Capacity established for the ensuing year for a unit from which capacity is to be sold to Corporation is more than or less than the Expected Capacity of such unit as specified in Exhibit A, the capacity to be sold and purchased during each period identified in Exhibit A for the ensuing year shall be Corporation's pro rata share of the Net Dependable Capacity determined by multiplying the amount of capacity sale **shown** for such unit in Exhibit A for each period by the ratio of the Net Dependable Capacity of the unit to the Expected Capacity of such unit as set forth in Exhibit A.

**2.3.4** In the event Net Dependable Capacity for any unit is less than the Expected Capacity, Southern Companies shall include in their notice of determination of Net Dependable Capacity under Section **2.3.1** information as to capacity which is available, consistent with Prudent Utility Practices (as defined in Section 10.5 hereof), from any remaining Net Dependable capacity in units specified in Exhibit **A** then owned by APC, GaPC, and GuPC or other coal-fired steam electric generating resources owned or operated by any of the Southern Companies, including the estimated additional capacity costs expected from any such other resources. Within fifteen (15) days of such notice, Corporation shall notify Southern Companies, in writing, whether it wishes to purchase a pro rata share (or any portion thereof) of such additional capacity. It is understood that Corporation's pro rata share shall be computed on the basis of all sales of unit power capacity from the unit under existing contemporaneous and future unit power sales from that unit. If any other purchaser of unit power capacity from the unit refuses to purchase such additional capacity, the refused amount of such capacity will be offered to Corporation on a pro rata basis with other purchasers of unit power capacity from the unit. To the extent capacity is made available pursuant to the above procedure from a unit other than those designated in Section **2.1**, such unit shall be considered to be a unit specified in Exhibit **A** for the period capacity from such unit is made available.

2.3.5 To the extent, notwithstanding the above efforts, capacity in the total amount specified in Section **2.2** hereof cannot be made available to Corporation during any year (or portion thereof) **because** the Net Dependable Capacity determination for one **or** more units specified in Exhibit **A** is less than the Expected Capacity of such unit or units, the sole obligation of Southern Companies shall be to offer to sell additional capacity to Corporation in the amount determined in accordance with Sections **2.3.1** through **2.3.4**.

**2.4** <u>Delav in Commercial Operation of Units</u>: Notwithstanding the schedule of sales set forth in Section **2.2** above, the obligation of APC to make capacity from the units specified in Exhibit A available to corporation may further be subject to delays in the projected dates for commercial operation of Units 3 and 4 of the Miller Plant. Construction of such units and any delays therein shall be governed by the following principles:

**2.4.1** APC agrees to use best efforts consistent with Prudent Utility Practices *to* design and construct, or to have designed and constructed, Units 3 and 4 of the Miller Plant so that such units shall have been declared available for commercial operation as of the date set forth in Exhibit A. Southern Companies shall not be liable to Corporation for any loss or damage for delays or failures to have such units declared available for commercial operation as of such dates due to causes not reasonably within their control including, but not limited *to*, acts of civil or military authority (e.g., courts or administrative agencies), acts of God, war, riot or insurrection, inability to obtain any required permits or licenses, blockades, embargoes, sabotage, epidemics, fires, floods, strikes, lockouts or other labor disputes or difficulties, unusually severe weather conditions, breakdowns of machinery or equipment, inability to obtain necessary materials or equipment, and economic constraints such as inability to secure adequate capital on reasonable terms for continued construction. In the event of any delay resulting from such causes, the time for performance shall be extended for a period of time reasonably necessary to overcome the effect of such causes. APC shall keep corporation informed of the construction schedules and any changes which alter the anticipated dates for commercial operation of the units, together with the reasons for such changes. The dates established in Exhibit A as the projected dates for commercial operation of Units 3 and 4 of the Miller Plant are based on the present plans of APC, and information available to it. It is recognized that the ability to predict such dates with exactness does not exist. In the event any of the dates for commercial operation are not met and the delay does not exceed one year from the projected date for commercial operation as set forth in Exhibit A, then it shall be conclusively presumed that the delay in the commercial operation of the unit resulted from events beyond the control of APC. In the event such delay extends beyond one (1) year, such presumption shall be revoked retroactive to the projected date for commercial operation set forth in Exhibit A.

**2.4.2** Southern Companies agree, that in the event Unit 3 or 4 of the Miller Plant is not available for commercial operation by the date on which unit power sales are scheduled to commence under this UPS Agreement as a result of the type of delay or failure described in Section 2.4.1, Southern Companies shall use their best efforts, consistent with

Prudent Utility Practices, to make the amount of capacity from such unit which was scheduled to be made available to corporation as specified in Exhibit A, available from other coal-fired steam electric generating resources owned or operated by any of the Southern Companies, including those resources specified in Section 2.1. To the extent such capacity is made available from a unit other than those designated in Section 2.1, such unit shall be considered to be a unit specified in Exhibit A for the period capacity from such unit is made available.

2.4.3 In the event Unit 3 or 4 of the Miller Plant is delayed due to reasons not excused under Section 2.4.1 but is available for commercial operation by the date on which unit power sales are scheduled to commence under this UPS Agreement, Southern Companies shall make adjustments in the capacity rates in accordance with the procedures specified in Article II of the Unit Power Sale Manual.

2.4.4 In the event Unit 3 or 4 of the Miller Plant is not available for commercial operation by the date on which unit power sales are scheduled to commence under this UPS Agreement, due to reasons not excused under Section 2.4.1, then in such event, as the sole obligation arising out of such delay, Southern Companies, shall (i) make available to Corporation unit power capacity from other coal-fired steam electric generating resources equal to the amount of capacity to have been furnished from the delayed unit as specified in Exhibit A with the understanding that capacity and energy rates of the units substituted for the delayed unit shall not. in total exceed the combined capacity and energy rates for the delayed unit calculated on the basis of the delayed unit being completed on the date stated in Exhibit A (a seventy-five percent (75%) capacity factor and a seventy-five percent (75%) load point on the average heat rate curve will be utilized in calculating the cost from the Miller Plant unit and the substitute unit); and (ii) make adjustments in the capacity rates in accordance with the procedure specified in Article II of the Unit Power Sale Manual, when and if the delayed unit becomes available for commercial operation. To the extent such capacity is made available from units other than those designated in Section 2.1, such. units shall be considered to be units specified in Exhibit A for the period capacity from such units is made available and the Expected Capacity of such units shall be defined as the nameplate rating less station service.

2.5 <u>Character of Sale</u>: The sale of unit power pursuant to this UPS Agreement shall not constitute a sale, lease, transfer or conveyance of an ownership interest in such units to Corporation, nor a dedication of ownership interest in such units to Corporation or any other party. Energy associated with capacity from units made available hereunder shall, however, be devoted to Corporation and the delivery of such energy to Corporation shall not be subject to preemption by Southern Companies for any other use. Except for capacity which is substituted during a year for capacity which was expected to be available, in accordance with Sections 2.4.2 or 2.4.3 or 2.4.4, the portion of such units to which Corporation and others have a contractual capacity entitlement, shall not be included in the determination of capacity pricing for the purposes of power sales made by Southern Companies to Corporation pursuant to any other power sales under contracts between Southern Companies and Corporation.

## ARTICLE III

## ENERGY AVAILABILITY

3.1 Energy: During each year specified in Section 2.2 (or portion thereof), Corporation will be entitled to schedule for delivery to the interconnection points identified in Section 4.1, energy in amounts up to a maximum of the capacity amount to which Corporation is entitled in the particular time period, as determined in accordance with Article 11, subject to the principles and determinations set forth in Sections 3.2 through 3.10. All scheduling times specified herein are based on established practices and procedures between the parties hereto and are subject to change upon mutual agreement of the parties hereto. All times specified herein shall be prevailing Central Time unless otherwise agreed.

3.2 Schedulins Enerav: By 11:00 a.m. on the day prior to commencement of energy deliveries under this UPS Agreement, and each day thereafter, Southern Companies will provide Corporation with an estimated hourly schedule of available energy for the following day. For Saturday, Sunday and Monday of each week such estimates, however, will be provided on the preceding Friday. Each estimate provided to Corporation will include, on a unit by unit basis, projected availability, together with the estimated applicable Base Energy Rates, Alternate Energy Rates, Supplemental Energy Rates, and Discretionary Energy Rates. By 1:30 p.m., on each day that Corporation receives an estimate of available energy, Corporation will provide Southern Companies with an estimated hourly schedule of capacity usage, and Southern Companies will provide Corporation, by 3:00 p.m., an estimate of energy rates associated with Corporation's estimated capacity usage. Corporation may not alter its hourly schedule of capacity usage, for each unit, on less than four (4) hours prior notice, unless otherwise mutually agreed upon by the Operating Representatives (as defined in Section 8.1) of Corporation and Southern Companies. The Operating Representatives will make a bona fide attempt to accommodate flexible energy scheduling (shorter than four (4) hours) and neither party hereto will unreasonably restrict or demand energy scheduling without sound operating reasons. In addition, Corporation will schedule total hourly capacity usage in amounts which are whole megawatts.

3.3 Unavailability or Ratina Change of Units: Except as proviaed in Section 3.8, Corporation shall not be entitled to energy associated with any unit which has been made available under Article 11, or portion of any such unit, at any time when and to the extent such unit, or portion thereof, is unavailable for service because of scheduled maintenance, forced outage or any other non-discretionary cause, or is partially derated from the Net Dependable Capacity of such unit determined in accordance with Section 2.3.1. In the event such a unit is derated but still capable of meeting the energy schedule of all utilities purchasing unit power from such unit, the energy will be scheduled from the unit provided that the derating is less than seven (7) days duration and ten (10) percent or less of the Net Dependable Capacity of the unit. If a derating is greater than ten (10) percent or a derating extends beyond seven (7) days or the unit is incapable of meeting the energy schedule, Corporation shall have the right to schedule energy associated with such unit, or to receive energy previously scheduled, up to a maximum of the capacity amount determined by the following formula for whatever period the derating may continue:

$$MUPC = \frac{UPC}{NDC} \times AOC$$

Where:

MUPC = Maximum Unit Power Capacity entitlement of Corporation from such unit after a rating change.

UPC = Unit Power Capacity entitlement of Corporation from such unit determined in accordance with Article II.

NDC = Net Dependable Capacity of such unit as determined in Section 2.3.1.

AOC = Actual operating Capability after a rating change as determined by the company responsible for operating such unit.

In the event the Actual Operating Capability of a unit is greater than the Net Dependable Capacity, Corporation will be entitled to schedule the energy associated with the increased Actual Operating Capability in accordance with the above formula provided that the increased output is greater than ten percent (10%) or the output increase extends beyond seven (7) days. Corporation will not be entitled to the additional energy associated with the increase in Actual Operating capability above the Net Dependable Capacity if the output increase is less than seven (7) days duration and ten percent (10%) or less of the Net Dependable Capacity.

3.4 Allocation of Energy Schedules to Generation Units: Schedules for hourly capacity usage provided by Corporation subject to Sections 3.1 and 3.2 above will be deemed to be requests for energy to be delivered from the generating units from which Corporation has a capacity entitlement, as determined under Article II and as modified by Section 3.3 for units unavailable or derated. Corporation may, upon four (4) hours notice, in accordance with Section 3.2, schedule energy from each generating unit for each hour in any amount, subject to Section 3.6, up to Corporation's maximum capacity entitlement from that generating unit. The energy so scheduled by Corporation and delivered by Southern Companies from the scheduled unit, is hereinafter called "Unit Energy." Unit Energy shall be supplied to all parties purchasing unit power from a generating unit on a pro rata basis based on the energy scheduled from that unit. Unit Energy supplied to Corporation shall be the lesser of (i) an amount equal to the total net generation of that unit multiplied by the ratio of the energy scheduled by Corporation to the total energy scheduled by all parties purchasing unit power from that unit, or (ii) the energy scheduled by Corporation. If the Unit Energy so supplied to Corporation is less than the energy scheduled from that unit in accordance with this Section 3.4, the balance of the energy scheduled shall be supplied as Alternate Energy pursuant to Section 3.7.

3.5 Minimum Energy Scheduling: Subject to the provisions of Sections 3.3 and 3.4, Corporation agrees to schedule energy made available from the units designated in Article II in excess of a fifty percent (50%) "Output Factor" on an annual basis for each calendar year through the year 2000. Output Factor is defined as the amount of Unit Energy (including Alternate Energy supplied in lieu of Unit Energy) and Replacement Energy scheduled by Corporation divided by the amount of energy made available by Southern Companies from the generating units designated in Article II, including Alternate Energy made available to Corporation. Corporation may reduce the fifty percent (50%) Output Factor for the calendar year 2001 and subsequent years if it gives written notice to Southern Companies at least one year in advance stating the amount of the requested reduction. If Corporation so elects to reduce the Output Factor, Southern Companies obligation to use reasonable efforts to make energy available on the basis of a ninety percent (90%) target capacity factor on an annual basis (as referenced in Sections 3.8, 3.8.4, 3.9, 4.2) will be reduced by one percent (1%) for each percentage point of reduction requested by Corporation (e.g., forty-five percent (45%) output Factor will result in a eighty-five percent (85%) target capacity factor). Once Southern Companies have met the target capacity factor for a calendar year, they shall be under no obligation to supply Supplemental Energy, Discretionary Energy or any Replacement Energy supplied in lieu of Supplemental Energy during the remainder of that calendar year.

3.6 Minimum Operation Capacity Obligation: During all periods when a unit made available to Corporation under Article II is operating at "Minimum Operating Conditions," corporation shall accept delivery of the energy associated with the Minimum Operation Capacity Obligation ("MOCO") of corporation for such unit. For the purpose of this UPS Agreement, Minimum Operating Conditions shall mean the periods of (a) ramping to a unit's minimum load point required for stable operation of the unit as determined from time to time by the entity responsible for operation of the unit; (b) operation at the minimum load point required for stable operation; or (c) operation at a point above the minimum load point.

Corporation shall be required to take energy from a unit when such unit is at the Minimum Operating Conditions pursuant to this Section 3.6(a) and (b) for any of the following reasons:

(i) Unit operation based on economic unit commitment practices:

(ii) Unit operation to manage fuel stockpiles;

(iii) Unit operation for freeze protection;

(iv) Unit operation for precipitator warm-up; and

(v) Unit operation for non-discretionary tests (e.g., environmental and performance tests).

Corporation shall be required to take energy from a unit when such unit is at the Minimum operating Conditions described in this Section 3.6(c) for any of the reasons set forth in (iii), (iv) and (v) above. Southern Companies agree that they will make best efforts to provide at least twenty-four (24) hour notification to Corporation of any planned non-discretionary unit tests or changes in unit operations to manage fuel stockpiles. When applicable, Corporation's Minimum Operation Capacity Obligation for each unit shall be determined by the following formula:

$$MOCO = \frac{UPC}{NDC} \times MC$$

Where:

MOCO = Minimum Operation Capacity Obligation of Corporation from such unit.

UPC = Unit Power Capacity entitlement of Corporation from such unit determined in accordance with Article II.

NDC = Net Dependable Capacity of such unit as determined in Section 2.3.1.

MC = Loading required for Minimum Operating Conditions as defined in this Section 3.6.

Southern Companies further agree that they will promptly notify Corporation if at any time the Minimum Operating Conditions of a given unit have changed and the reasons for such change.

**3.7** Option to Furnish Scheduled Energy from Alternate Resources: Energy requested by Corporation, and deemed to be scheduled from specific units, as determined in Section 3.4, may be provided by Southern Companies from other resources owned or operated by Southern Companies. Such energy, delivered from resources other than those from which such energy was scheduled pursuant to Section 3.4, during periods in which such specific units are available for operation, is called "Alternate Energy." Any Alternate Energy delivered by Southern Companies in lieu of energy from a specific unit shall be delivered to all parties purchasing unit power from such unit on a pro rata basis to each party based on energy scheduled from that unit.

Alternate Energy may be supplied by Southern Companies from an assigned unit or from the units in economic dispatch on the system of Southern Companies at the time, at the sole option of southern Companies. However, it is agreed that Alternate Energy will normally be supplied from units in economic dispatch except when system operating conditions indicate otherwise. Southern Companies will notify Corporation of the amount of Alternate Energy to be made available, the selected energy sources, and the estimated energy rates at the times set forth in Section 3.2.

**3.8** Supplemental Enerav Scheduling: APC, GaPC and GuPC agree to use reasonable efforts to make energy available to Corporation from each unit to which Corporation has a capacity entitlement pursuant to Article 11 on the basis of a ninety percent (90%) target capacity factor on an annual basis or such target capacity factor which may be in effect for the calendar year **2001** and subsequent calendar years as a result of the provisions of Section **3.5**. It is recognized that such efforts to achieve such target may be frustrated by forced outage of the units, needs for repair or maintenance of the units, governmental restrictions or other non-discretionary reasons. The sole obligation of APC, GaPC, GuPC and Southern Companies for the failure to achieve such target capacity factor for each unit shall, where due *to* the aforesaid reasons, be as follows:

**3.8.1** During periods in which a unit to which Corporation has a capacity entitlement under Article II is unavailable for service, Southern Companies shall use their best efforts, consistent with Prudent Utility Practices, to make available supplemental energy from other coal-fired or comparably-priced generating resources available to Southern Companies equal to one hundred percent (100%) of Corporation's entitlement in such unit under Article 11.

**3.8.2** During periods in which a unit to which Corporation has a capacity entitlement under Article II is partially derated, Southern Companies shall use their best efforts, consistent with Prudent Utility Practices, to make available supplemental energy from other coal-fired or comparably priced generating resources available to Southern Companies equal to one hundred percent (100%) of Corporation's entitlement in such unit under Article II less Corporation's entitlement to schedule energy from such derated unit pursuant to Section **3.3**. Energy made available to Corporation pursuant to this Section **3.8.2** and Section **3.8.1** is called **"Supplemental Energy."**

**3.8.3** In the event the Supplemental Energy provided for in Sections **3.8.1** and **3.8.2** cannot be provided from coal-fired or comparably-priced generating resources, Southern Companies agree to use their best efforts, consistent with Prudent Utility Practices, to make energy available from higher-priced generating resources of Southern Companies in amounts equal to the Supplemental Energy provided for in such sections. Such energy made available by Southern Companies and scheduled for delivery, at Corporation's election, shall be deemed Supplemental Energy.

**3.8.4** Southern Companies will not be obligated to provide Corporation any additional Supplemental Energy for the remainder of any year from and after the date on which Southern Companies have made available to Corporation for scheduling under this **UPS** Agreement (except for energy made available under Sections **3.8.3** and **3.9** but not taken by Corporation and for energy made available but not deliverable because of Southern Companies' inability to deliver due to transmission contingencies of less than two **(2)** weeks duration pursuant to Section **4.2)** energy in the aggregate equal to the target capacity factor percentage of Corporation's total capacity entitlement for such year, as determined in accordance with Article II, multiplied by the number of hours in such year. To the extent any energy requested by Corporation during the remainder of any such year is not available from units to which Corporation has a capacity entitlement, such energy and associated capacity shall be furnished, if at all, under other rate schedules between the parties hereto.

**3.8.5** Supplemental Energy shall mean energy available on the systems of Southern Companies, not needed at that time on their own systems to meet their own system's requirements (including power used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery under this **UPS** Agreement. The only power sale commitments taking precedence over the availability of Supplemental Energy are: (i) any seasonal energy or capacity exchange agreements now existing or entered into in the future: (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future: (iii) any other unit power sales with other utilities or third parties now existing (including, but not limited to, provisions for Unit Energy, Alternate Energy and Supplemental Energy): (iv) any future unit power sales with other utilities (including provisions for Unit Energy and Alternate Energy); and **(v)** any short-term power being supplied under the provisions of a now existing contract with Alabama Electric Cooperative, Inc. After Supplemental Energy has been made available in accordance with the existing unit power contracts with **FPL** and JEA, it is understood that Supplemental Energy made available for delivery by Southern Companies pursuant to this **UPS** Agreement will be made available to Corporation and other contemporaneous parties (as defined in Section 10.10 hereof) on a pro rata basis based upon each contemporaneous party's capacity entitlement under their respective contemporaneous unit power sales contracts in the unit unavailable for service.

Supplemental Energy, if available, will be supplied from the units in economic dispatch on the systems of Southern Companies at the time. Southern companies will notify Corporation of the amount of Supplemental Energy to be made available and the estimated energy rates at the times set forth in Section 3.2.

**3.9** Discretionary Energy Scheduling: In addition to the energy made available pursuant to Sections 3.8.1, 3.8.2 and 3.8.3, if requested by Corporation, Southern Companies will make available, after meeting all other obligations of Southern Companies and any energy sales of opportunity, energy from other coal-fired generating resources owned or operated by the Southern Companies, up to ten percent (10%) in excess of Corporation's total capacity entitlements. Energy made available to Corporation pursuant to this section is called "Discretionary Energy." If at Corporation's election such Discretionary Energy is scheduled for delivery, it will be considered as energy delivered in an effort to achieve the target capacity factor provided for in Section 3.8.

3.9.1 Discretionary Energy shall mean energy available on the systems of Southern Companies, not needed at that time to meet their own system's requirements and needs, any power sale commitments now existing or entered into in the future, and any other energy sales of opportunity under agreements with Corporation and other utilities (or third parties) now existing or entered into in the future. Discretionary Energy under this UPS Agreement shall have precedence over Discretionary Energy provisions in future unit power sales agreements.

**3.9.2** After Discretionary Energy has been made available in accordance with existing unit power sales contracts with FPL and JEA, Discretionary Energy made available for delivery by Southern Companies will be made available to Corporation and other contemporaneous parties on a pro rata basis based upon each such party's capacity entitlements under its respective contemporaneous unit power sales contract for the term of this UPS Agreement. Discretionary Energy, if available, will be supplied from the units in economic dispatch on the systems of Southern Companies at the time. Southern Companies will notify Corporation of the amount of Discretionary Energy to be made available and the estimated energy rates at the times set forth in Section 3.2.

**3.10** Replacement Energy Scheduling: In addition to Supplemental Energy, Alternate Energy and Unit Energy, Southern Companies shall also make available replacement energy, hereinafter called "Replacement Energy." Replacement Energy will be made available by Southern Companies to Corporation from the lowest energy cost generating resources that can be made available after priorities under Section 3.10.1 are satisfied, to permit Corporation to substitute such energy for Alternate Energy, Supplemental Energy and Unit Energy (but not including energy associated with Minimum Operation Capacity Obligation as defined in Section 3.6). Southern Companies will furnish information with respect to generating capacity available on their electric systems which might be made available to supply Replacement Energy at the times as set forth in Section 3.2. This information will include (i) the incremental cost, as set forth in Section 6.9 of the Replacement Energy that can be made available; and (ii) the quantity and period of time such energy is expected to be available. Southern Companies, in the sole discretion of SCS, shall determine if capacity is available on their systems for Replacement Energy.

3.10.1 Replacement Energy shall be supplied to contemporaneous parties from generating units in economic dispatch on the systems of Southern Companies after serving Southern Companies' own system requirements and the following transactions which shall have priority: (i) any seasonal or capacity exchange agreements now existing or entered into in the future: (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future; (iii) any unit power sales agreements for the sale of capacity and energy from a specific unit or units (including any Unit Energy or Alternate Energy furnished under provisions similar to that specified in this UPS Agreement) now existing or entered into in the future: (iv) any Long Term Power sales with other utilities or third parties which were executed prior to the date of this UPS Agreement; (v) any sales of Supplemental Energy under the provisions of unit power sales agreements (now existing or entered into in the future) similar to the provisions of this UPS Agreement: (vi) any Replacement Energy sales under existing unit power sales contracts with FPL and JEA; and (vii) any short term capacity sales under the existing interchange agreement between APC and Alabama Electric Cooperative, Inc.

3.10.2 Each Replacement Energy transaction shall be agreed upon by the parties hereto prior to commencement of delivery of such energy. It is anticipated that, after Southern Companies have supplied the information pursuant to Section 3.10, the parties will establish a preliminary schedule for energy deliveries hereunder for the next day. Approximately thirty (30) minutes before the transaction is scheduled to commence, Southern Companies shall quote the price in dollars per megawatt hour ($/MWH) for Replacement Energy for the next hour and will provide similar quotes for each subsequent hour during the period of the transaction. As soon as practicable after the time of each price quote for the next hour, Corporation shall determine whether or not to take Replacement Energy during that next hour. If after the time of the price quote for the next hour and prior to the time of the price quote for the subsequent hour Southern Companies determine, in their sole judgment, that all or a portion of the then scheduled Replacement Energy can no longer be delivered, Southern Companies shall give as much notice as possible of the need for Corporation to change its schedule of Replacement Energy to energy that may be available under other provisions of this UPS Agreement at the next scheduling time for the subsequent hour. The delivery of Replacement Energy during the next hour may be continued at the option of Corporation subject to the pricing provisions of Section 6.9.

**3.10.3** Replacement Energy is not intended and shall not be interpreted to change or modify the obligations, rights and duties of the parties under other provisions of Article III of this UPS Agreement except that Replacement Energy schedule hereunder will be deemed to satisfy the provisions of Section **3.5**.

**3.11** <u>Energy Entitlement Associated with Increased Peak Capacity</u>: Southern Companies intend, under emergency conditions, to operate certain of their generating units, including some of the units identified in Exhibit A to this Agreement, to obtain Increased Peak Capacity ("IPC"). In addition to the energy supplied to Corporation by Southern Companies pursuant to Sections 3.4, **3.7**, **3.8**, and **3.9** of this Agreement, Corporation will be entitled to energy associated with the IPC ("IPC Energy") of Corporation's capacity entitlement under the terms of this Agreement based on the following conditions:

3.11.1 Southern Companies in their sole discretion will determine for the next calendar year, based upon unit testing of IPC capability, the amount of IPC associated with the capacity identified in Exhibit **A** to the Agreement and the annual maximum hours of operation for the IPC. Corporation's annual energy entitlement of IPC Energy is calculated by summing its pro rata shares of IPC capability of the units identified in Exhibit A (based upon the proportional amount of unit power capacity purchased out of the unit by Corporation) multiplied by the annual maximum hours of operation for IPC. On or before November 1 of each year during the term hereof, Southern Companies will inform Corporation of its annual IPC Energy entitlement for the following Contract Year.

3.11.2 Southern Companies expect to obtain IPC for certain of their generating units by operating the units at a higher output than the Net Dependable Capacity of the units for up to a maximum of **263** hours during a calendar year. It is anticipated that IPC for the units specified in Exhibit A will be obtained by operating the units with valves wide open at design throttle pressure with all feedwater heaters in service. Southern Companies do not intent to operate the units identified in Exhibit A on overpressure to obtain IPC.

**3.11.3** In the event Southern Companies determine that the IPC associated with a unit is zero for the next calendar year, they shall have no obligation to supply Corporation and IPC Energy in any amount during such year.

3.11.4 Southern Companies and Corporation agree that IPC will not be included as part of the Net Dependable Capacity for each unit or any other component of the formula rate for the determination of the monthly production capacity charge rate (in $/KW-month) set forth in Article II of the Unit Power Sale Manual and will not be included in the calculation of the monthly capacity charges as provided in Section **6.2** of this Agreement.

**3.11.5** During periods when Corporation desires to schedule IPC Energy, Corporation will supply Southern Companies with a requested schedule for each hour of the period. Corporation will be entitled to schedule IPC Energy in an amount up to twenty-five **(25)** megawatts per hour limited by its annual entitlement to IPC Energy (in megawatt hours), as determined in accordance with Section 3.11.1. Southern Companies will, upon receipt of a requested schedule, determine the amount of IPC Energy available for scheduling by Corporation. After determining the availability of IPC Energy, Southern Companies will promptly notify Corporation if the requested schedule can be accommodated. The IPC Energy will be scheduled to the extent that Replacement Energy is available under the priorities and conditions as specified under Section **3.10** hereof. Southern Companies will inform Corporation of the amount of IPC Energy to be made available and th estimated energy rates at the time of Corporation's requested schedule.

**3.11.6** IPC Energy may be supplied from generating units in economic dispatch on the systems of Southern Companies.

**3.11.7** Southern Companies will not be obligated to supply Corporation any additional IPC Energy for the remainder of any year from and after the date on which Southern Companies have provided IPC Energy equal to Corporation's annual energy entitlement to IPC, as determined in accordance with Section 3.11.1. Further, any portion of Corporation's annual energy entitlement to IPC that has not been scheduled and is remaining at the end of each Contract Year will not be carried over and made available for scheduling in the following year.

ARTICLE IV

ESTABLISHMENT OF DELIVERY POINTS
AND PROVISION FOR TRANSMISSION CONTINGENCIHS

**4.1** Points of Delivery: Southern Companies shall deliver the power and energy purchased by Corporation hereunder to the Points of Delivery specified in Article III of the Interchange Contract.

**4.2** Transmission Continsencies: In the event energy scheduled to be delivered hereunder cannot be delivered or received because of contingencies of any nature affecting transmission facilities of either party hereto, there shall be no reduction in capacity charges hereunder: provided, however, where such inability to deliver energy hereunder continues for more than two (2) weeks because of a failure of Southern Companies to remedy problems within their systems, then Southern Companies shall waive capacity charges for periods during which such deliveries continue to be affected in excess of two (2) weeks.

During the period of a transmission contingency of less than two (2) weeks in duration within Southern Companies' systems, energy which could not be delivered to Corporation shall not constitute energy made available toward the target capacity factor provided for in Section 3.8. Energy which cannot be delivered due to such transmission contingencies will not be considered as energy made available to Corporation for determination of the Output Factor provided for in Section 3.5. During the period of a transmission contingency of more than two (2) weeks in duration, the parties hereto acknowledge and agree that certain adjustments in operating and accounting procedures will be necessary and that such adjustments will be made in an equitable manner consistent with principles set forth in this UPS Agreement. Such adjustments will be referred to the Operating Representatives for resolution.

To the extent the occurrence of a contingency is controllable, Southern Companies shall use their best efforts consistent with Prudent Utility Practices to prevent the occurrence of contingencies which would result in restricted scheduled deliveries of power and energy hereunder and if not prevented shall promptly exert best efforts consistent with Prudent Utility Practices to restore the affected facilities to provide for deliveries as scheduled.

4.3 Limitation of Transmission Facilities: Southern Companies and Corporation recognize and acknowledge that transmission facilities pursuant to this UPS Agreement and other interconnections now existing or which may be constructed in the future between Southern Companies and other electric utilities in Florida are governed by principles and guidelines set forth in the Reliability Coordination Agreement effective July 1, 1980 between Southern Companies and Florida Electric Power Coordinating Group ("RCA"). Southern Companies and Corporation agree that in order for the full benefit of this UPS Agreement to accrue to the parties hereto while preserving the reliability of their systems, such principles and guidelines must be observed throughout the duration of existing power purchase and sale agreements, this UPS Agreement, and any and all power purchases and sales contemplated in the future.

Southern Companies and Corporation hereby agree to observe "Transfer Limit" between Southern Companies and Florida (excluding GuPC). Transfer Limit has been defined by the Executive Council of the RCA as the first contingency transfer capability utilizing the criteria established by the Executive Council. In the event the RCA or its successor agreement expires or fails to define Transfer Limit, Transfer Limit will be defined for this UPS Agreement by the criteria set forth below:

4.3.1 Transfer Limit: The Southern-Florida (excluding GuPC) Transfer Limit is defined as the total amount of power that can be transferred from Southern Companies to Florida (excluding GuPC) for periods up to several days with an assurance of adequate system reliability, based on the most limiting of the following:

(a) With all transmission facilities in service, all facility loadings are within normal ratings and all voltages are within normal limits.

(b) The bulk power electrical system is capable of absorbing the dynamic power swings without separation between Southern Companies and Florida (excluding GuPC) and of remaining stable following the loss of any single transmission circuit, breaker, or transformer in Southern Companies systems including the Southern-Florida interconnection circuits, or following the loss of the largest generating unit in Florida or in Southern Companies' systems.

(c) After the dynamic power swings following a disturbance contemplated under (b), but before operator-directed system adjustments are made, all transmission facility loadings are within emergency ratings and all voltages are within emergency limits.

**4.3.2** The parties hereto agree that, with the exception of the period January 1, 1993 through May 31, 1993, the total capacity and energy to be delivered to Florida (except GuPC) under existing unit power sales contracts with FPL and JEA, this UPS Agreement (including capacity and energy which may be taken under early option provisions), contemporaneous unit power sales contracts with other contemporaneous parties (including capacity and energy which may be taken under early option provisions), and an existing contract providing for Long Term Power sales to the City of Tallahassee can be accommodated under the now-existing Transfer Limit and should such Transfer Limit be reduced, so as to limit Southern Companies' ability to deliver energy as a result of actions by Corporation or conditions on the electric system of Corporation, there will not be a reduction in capacity charges under this UPS Agreement except in instances caused by actions of Southern Companies or conditions on the electric systems of Southern Companies and such reduction in Transfer Limit continues for more than two (2) weeks. With respect, however, to the period January 1, 1993 through May 31, 1993, Corporation and Southern Companies recognize that the Transfer Limit may be exceeded as a result of the exercise by Corporation and other contemporaneous parties of early option provisions similar to the early option incorporated in Section 2.2.1 of this UPS Agreement. In such event, the capacity to be sold under the early options will be prorated among Corporation and other contemporaneous parties (based upon the total unit power capacity sales to Corporation and other contemporaneous parties on June 1, 1995) so as not to exceed the Transfer Limit; provided, however, that with respect to such early option capacity, Corporation shall only pay for that amount of capacity it is entitled to receive under the early option after any proration.

4.3.3 If either party hereto desires to schedule transfers between Southern companies and Florida (excluding GuPC) in excess of the level of transactions under existing unit power sales contracts with FPL and JEA, this UPS Agreement (including capacity and energy which nay be taken under early option provisions), contemporaneous unit power sales contracts with other contemporaneous parties (including capacity and energy which may be taken under early option provisions), and an existing contract providing for Long Term Power sales to the City of Tallahassee so as to exceed the then existing Transfer Limit, then such party, in conjunction with any other third parties in interest, shall install facilities on their system or take any actions which are necessary to permit the desired transfer in conformance with this Section 4.3.

4.3.4 Schedules of power by Southern Companies to Florida (except GuPC) in excess of the level of transactions under existing unit power sales contracts with FPL and JEA, this UPS Agreement (including capacity and energy which may be taken under early option provisions), contemporaneous unit power sales contracts with other contemporaneous parties (including capacity and energy which may be taken under early option provisions), and an existing contract providing for Long Term Power sales to the City of Tallahassee may create an undue burden on the transmission system of Corporation, even though such schedules are within the Transfer Limit established under this Section 4.3. To the extent Southern Companies propose to make any additional sales of power or delivery of energy for others in excess of such amounts to utilities in Florida for Periods of one year or more, Southern Companies shall notify Corporation of such proposal and Corporation agrees to notify Southern Companies, within sixty *(60)* days after receipt of notice of such proposal whether, in its judgment, based on a good faith evaluation by Corporation, a reasonable probability exists that such sale will result in the imposition of an undue burden on the transmission system of Corporation. In the event Corporation fails to identify any such burden within such time, the agreement for such sale by Southern Companies shall not be prohibited by this UPS Agreement. To the extent Corporation identifies any potential burden on its transmission system resulting from such sale, Corporation agrees to meet with Southern Companies and the party or parties to whom such sale is to be made to discuss in good faith what facilities or operating procedures are necessary to avoid such burden. In the event no agreement can be reached as to methods of avoiding such burdens, Southern Companies shall not enter into such sales.

In the event Southern Companies schedule transfers to Florida (except GuPC) in excess of the level of transactions identified above under schedules involving sales of power, or delivery of energy for others of less than one year duration, then, to the extent such scheduled transfers together with other sales do not exceed the Transfer Limit established under Section 4.3 above, such schedule of power shall not be prohibited by this UPS Agreement unless Corporation notifies Southern Companies that, in its reasonable judgment made in good faith, a burden on its transmission system has been created by such schedule. Southern Companies shall upon receipt of such notice reduce its schedule of such transfers to an acceptable level.

ARTICLE V

PROCEDURE FOR CAPACITY AND ENERGY RATES

5.1 Unit Power Sale Periodic Rate Computation Procedure: Corporation and Southern Companies recognize that the cost of providing the unit power and electric services contemplated herein may change during the term of this UPS Agreement. Thus, in order for Southern companies to be compensated fairly and adequately, it will be necessary to revise or update, on a periodic basis, the cost, expense, and investment figures utilized in the derivation of the capacity charges and certain components of the energy charges provided for in this UPS Agreement.

In order to facilitate revisions or updates of the charges calculated under the basic procedure and methodology outlined in this UPS Agreement, Southern Companies have adopted a Unit Power Sale Periodic Rate Computation Procedure Manual ("Unit Power Sale Manual") which is attached hereto as Exhibit C to this UPS Agreement and incorporated herein by reference. The Unit Power Sale Manual describes in detail the methodology and procedure to be utilized in the periodic calculation of charges provided for in this UPS Agreement.

The Unit Power Sale Manual, together with this UPS Agreement shall serve as a formulary rate allowing periodic revisions of the charges to reflect changes in costs of providing the services contemplated by this UPS Agreement. The capacity charges and certain components of the energy charges calculated in accordance with the Unit Power Sale Manual will be shown on the Unit Power Sale Informational Schedule further described in Section 5.2 herein.

5.2 Unit Power Sale Informational Schedule: The Unit Power Sale Informational Schedule for Southern Companies showing estimated charges for the unit power sales contemplated by this UPS Agreement is attached hereto as Exhibit D for example purposes only and will be replaced with an updated Unit Power Sale Informational Schedule showing the initial charges for the unit power sales on or before November 1 of the year preceding the first calendar year in which the unit power sales occur. The Unit Power Sale Informational Schedule will be revised for each calendar year during the continuation of unit power sales hereunder. Revisions of charges contained in the Unit Power Sale Informational Schedule shall follow the methodology and procedure set forth in this UPS Agreement and the Unit Power Sale Manual. A revised Unit Power Sale Informational Schedule shall be submitted by Southern Companies to Corporation on or before November 1 of each year for application on January 1 of the following year. This time period will allow Corporation and Southern Companies to verify that the charges contained in the revised Unit Power Sale Informational Schedule have been computed in accordance with this UPS Agreement and the methodology and procedure set forth in the Unit Power Sale Manual. Since the charges contained in the revised Unit Power Sale Informational Schedule will be computed in accordance with formulary rate method and procedures described in this UPS Agreement and the Unit Power Sale Manual, it is the intent of Southern Companies and Corporation that such revisions will not be changes in rates which would require a filing and suspension under the Federal Power Act and the applicable rules and regulations of FERC. A revised Unit Power Sale Informational Schedule will be filed with FERC, or its successor in interest, for informational purposes to show the application of the formulary rate method and procedure and the resulting charges provided for in this UPS Agreement and the Unit Power Sale Manual.

5.3 Unilateral Revision of Capacity and Energy Rates and/or Unit Power Sale Periodic Rate Computation Procedure Manual: In addition to the right to change the charges as described in Sections 5.1 and 5.2 above, Southern Companies shall have the right to amend the formulary capacity and energy rates established in this UPS Agreement, Unit Power Sale Manual, and Unit Power Sale Informational Schedule. This right shall be limited to the following changes in the formulary capacity and energy rates: (i) changes in provision for percentage return on equity capital: and (ii) changes in provisions establishing capacity losses and energy losses. Southern Companies shall have the right to unilaterally make application to FERC for a change in rates under Section 205 of the Federal Power Act and pursuant to FERC's rules and regulations promulgated thereunder with respect to the specific matters identified above. In all such events, Corporation shall be free to support or contest such amendment or raise any objection it may have to such amendment before FERC. As to the two above-identified subjects over which Southern Companies retain the right to unilateral filing under Section 205, Corporation shall have the right to seek changes under Section 206 under a just and reasonable and non-discriminatory standard, as opposed to a public interest standard. Southern Companies shall further have the right to file unilateral changes in the capacity and energy rates to the extent, at any time, any additional legitimate cost not now in existence, is incurred with respect to charges for capacity and energy (including government impositions), which such cost is not recouped under the capacity and energy rates set forth herein. Corporation will support any such change and cooperate and assist Southern Companies in securing approval by FERC of such additional charges to the extent the additional charge can reasonably be defended by Corporation. Corporation has the right to oppose any such cost (or part thereof) which it, in good faith, does not consider to be an additional or legitimate cost not now in existence.

5.4 Unilateral Chanues Resulting from Regulatory Action: In addition to the rights set forth in Section 2.2.5, Southern Companies shall further have the right to file one or more unilateral changes in the capacity and energy rates under this UPS Agreement if the rates provided for in this UPS Agreement are disapproved or modified by FERC, or its successor. Corporation agrees to support any such change and cooperate and assist Southern Companies in securing approval by FERC of such change to the extent the change by Southern Companies would not result in the imposition of higher estimated charges to Corporation than those which would have been produced under this UPS Agreement prior to the action taken by FERC; provided, however, that Corporation's support is contingent upon its determination that it can reasonably defend such change otherwise: If Corporation determines that it cannot, in good faith, support such change nothing herein will prevent it from opposing the change before FERC.

5.5 <u>Establishment of Initial Return on Common Equity and Provisions for Change in Return on Common Equity</u>: The initial return on common equity to be included in the formula rates to establish production and transmission capacity costs for unit power purchased and sold from the Miller Plant and Unit **3** of the Scherer Plant shall be determined as follows:

(i) if, prior to or after the commencement of sales under this Agreement, the current return on common equity component (13.75%) in the Agreement is left unchanged as a result of a final order of the court of appeals in Case No. 81-1595 or the ultimate resolution of the investigation in Docket No. EL91-29-000 (including any order on rehearing and judicial review), the initial return on common equity to be observed beginning January 1, 1994 will be **13.75%**, with no refund obligation;

(ii) if, prior to the commencement of sales under this Agreement, the current return on common equity component in the Agreement is changed by order of the FERC in Docket No. EL91-29-000, the initial return on common equity to be observed beginning January 1, 1994 will be the return established by the FERC in that order; and

(iii) if, at the time of commencement of sales under this Agreement the FERC has not issued its order in Docket No. EL91-29-000, the initial return on common equity component to be observed beginning January 1, 1994 will be **13.75%**, subject to refund (with interest) from the commencement of service, pending the establishment of a return by the FERC.

Any reduction in the return on common equity ordered by the FERC will be made subject to the ultimate resolution of the investigation (including any order on rehearing or judicial order). In any event, during the three (3) month period following the issuance of a decision of the Court of Appeals in Case No. 91-1595 invalidating the investigation or an order of the FERC in Docket No. EL91-29-000, representatives of Southern Companies and Corporation shall meet to discuss whether such return on equity remains appropriate for use. If the parties hereto agree upon a new return on common equity to be incorporated in this UPS Agreement, Southern Companies will make an appropriate filing with the FERC within fifteen (15) days of such agreement. In the event the parties hereto are unable to agree upon an appropriate return on common equity within the three (3) month period, Southern Companies will file, with fifteen (15) days subsequent to the expiration of the three (3) month period, a return on common equity to be incorporated into this UPS Agreement and Unit Power Sale Manual together with a request that the FERC establish an appropriate return on common equity to be observed by the parties hereto under the just and reasonable and non-discriminatory standard. With respect to any return on common equity reflected in a filing by Southern Companies following the three (3) month period, charges attributable to such return on common equity shall be subject to refund from the filing date of any pleading. The return **on** common equity established by the FERC in the event of failure to agree upon such return shall be subject to subsequent change by unilateral filing of Southern Companies under Section 205 of the Federal Power Act and regulations thereunder or by order of the FERC under Section 206 of the Federal Power Act upon complaint by Corporation. As to any such subsequent changes, in the event that the FERC sets the return on common equity €or hearing under Section 206, (i) the FERC's determination of the return on equity shall be rendered under the **just** and reasonable and non-discriminatory standard rather than under the public interest standard; and (ii) only in the event of a proceeding initiated by complaint of Corporation, charges attributable to the return on common equity shall be subject to refund from the filing dated of any pleading requesting such proceeding.

## ARTICLE VI

## CHARGES FOR SERVICE

**6.1** Rates: Corporation shall pay each month for the capacity and energy furnished hereunder and transmission losses associated therewith on the following bases:

*6.2* Capacitv Rates: With respect to each unit from which capacity is made available to Corporation pursuant to Article II, the capacity charge shall be the sum of the dollar per kilowatt-month charge produced by the applicable formulary rate set forth in Article II of the Unit Power Sale Manual for each unit plus the dollar per kilowatt-month charge produced by the formulary rate set forth in Article III thereof for associated transmission capacity. The dollar per kilowatt-month charge for each unit produced by the formulary rate shall be multiplied by the number of kilowatts of capacity from such unit made available to Corporation pursuant to Article II hereof each month and the sum of the charges for all units during each month shall be paid by Corporation in accordance with Section **7.1** hereof (Billing and Payment). In the event the Net Dependable Capacity of any unit from which capacity sales are to be made to FPC is determined to be zero for any year, Corporation shall be responsible for the dollar per kilowatt month charge for such unit produced by the formulary rate assuming such Net Dependable Capacity equaled the Expected Capacity and multiplying such charge by the capacity to which Corporation would have been entitled in such circumstance. Corporation shall not be responsible for capacity charges for any such unit to the extent the Net Dependable Capacity for such unit is zero for any year due to causes within the reasonable control of the Company responsible for operating the unit, as governed by Prudent Utility Practices. Southern Companies shall true-up the capacity charge, on **a** periodic basis (not less frequently than annually), to reflect actual costs. Such true up will be performed in accordance with Article IX of the Unit Power Sale Manual.

**6.3** Base Enersv Rates: For Unit Energy supplied to Corporation during each month from the units specified in Exhibit A pursuant to Section **3.4**, Corporation shall pay an amount per MWh (hereinafter called Base Energy Rate) delivered from each unit equal to the sum of the following items (expressed in $/MWh):

(a) Fuel Cost €or each unit, which is defined in Article IV of the Unit Power Sale Manual, together with the procedure for determining this component of the energy charge.

(b) The variable operation and maintenance expenses for the unit. The procedure for determining the component of the energy charge is described in Article V of the Unit Power Sale Manual.

(c) The in-plant fuel handling expenses for the unit. The procedure for determining this component of the energy charge is described in Article V of the Unit Power Sale Manual.

(d) Compensation for transmission losses, based on the average transmission **loss** percentage ($\%L_e$). The procedure for determining "$\%L_e$" is set forth in Article VII of the Unit Power Sale Manual. Using (a), (b) and (c) above,

$$(d) = [(a) + (b) + (c)] \left[ \frac{(\%L_e \div 100)}{1-(\%L_e \div 100)} \right]$$

6.4 <u>Alternate Energy Rates</u>: For energy supplied to Corporation at any time from alternate sources owned or operated by Southern Companies, in accordance with Section **3.7**, Corporation shall pay an amount per **MWH** delivered which is the least of (i) the Base Energy Rate as determined in Section **6.3** for the unit for which Alternate Energy is provided; (ii) the Normalized Energy Rate as determined in Section **6.6** for the unit for which Alternate Energy is provided; or (iii) one-half (0.5) the sum of the Base Energy Rate for such unit and the cost **of** such Alternate Energy determined by the following principles:

For Alternate Energy whether supplied from an assigned unit **of** Southern Companies, or from the units in economic dispatch on the systems of Southern Companies, the cost of such energy ($/MWH) shall be the incremental expense of the assigned unit of the units in economic dispatch, such energy shall be considered as having been delivered at the incremental cost of Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery of such energy. The **only** power sale commitments taking precedence before delivery of such Alternate Energy are: (i) any seasonal energy or capacity exchange agreements now existing or entered into in the future; and (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future. The expense .fromassigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, emission allowance replacement costs, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

*6.5* Supplemental Enersv Rates: For energy supplied to Corporation at any time pursuant to Section 3.8, Corporation shall pay an amount per MWH delivered which is the greater of (i) the Base Energy Rate for the unit for which Supplemental Energy is provided, as determined in Section *6.3;* provided, however, such Base Energy Rate shall be limited to a value no greater than the Normalized Energy Rate as determined in Section 6.6 for such unit; or (ii) the incremental cost of the units in economic dispatch incurred by Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery of such Supplemental Energy as defined in Section 3.8.5. The expense from assigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, emission allowance replacement costs, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

*6.6* Normalized Energy Rates: The Normalized Energy Rate each month for each unit specified in Exhibit A shall be equal to the sum of the following item (expressed in $/MWh):

(a) Normalized Fuel cost for the unit, which is defined in Article IV of the Unit Power Sale Manual.

(b) The variable operation and maintenance expenses for the unit as described in Article V of the Unit Power Sale Manual.

(c) The in-plant fuel handling expenses for the unit as described in Article V of the Unit Power Sale Manual.

(d) Compensation for transmission losses, based on average transmission loss percentage ($\%L_e$) set forth in Article VII of the Unit Power Sale Manual. Using (a), (b), and (c) above,

$$(d) = [(a) + (b) + (c)] \left[ \frac{(\%L_e \div 100)}{1-(\%L_e \div 100)} \right]$$

6.7 Station Service Charses: For station service energy required each month for a unit specified in Exhibit A during the hours in which the net electrical output of such unit is equal to or less than zero, Corporation shall pay an amount per MWH, for a pro rata share of such station service energy based on the ratio of Corporation's capacity entitlement in such unit pursuant to Article II to the Net Dependable Capacity of such unit, equal to the Base Energy Rate of such unit as determined in Section *6.3;* provided, however, such Base Energy Rate shall be limited to a value no greater than the Normalized Energy Rate as determined in Section 6.6 for such unit.

6.8 Discretionary Energy Rates: For energy supplied to Corporation at any time pursuant to Section 3.9, Corporation shall pay an amount per MWH determined which is the greater of (a) Weighted Average Energy Rate for Corporation's pro rata share of all units as determined by the following formula:

$$WAER = \frac{UPC_1 \times ER_1}{UPC_1 + UPC_2 + \ldots UPC_N} +\ldots+ \frac{UPC_N \times ER_N}{UPC_1 + UPC_2 + \ldots + UPC_N}$$

Where:

WAER = Weighted Average Energy Rate for Corporation's pro rate share of all units.

N = Total number of units to which Corporation has capacity entitlement.

$UPC_N$ = Unit power Capacity entitlement of Corporation from such unit determined in accordance with Article 11.

$ER_N$ = Unit's respective Energy Rate which is lesser of (1) the Base Energy Rate of such unit as determined in accordance with Section 6.3; or (2) the Normalized Energy Rate o such unit as determined in accordance with Section 6.6.

or (b) the incremental cost of the units in economic dispatch incurred by Southern Companies after serving their own systems' requirements and needs, and any other energy sales taking precedence before delivery of such Discretionary Energy as defined in Section 3.9.1. The expense from assigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, emission allowance replacement costs, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

6.9 Replacement Energy Rates: For Replacement Energy supplied to Corporation pursuant to Section 3.10, Corporation shall pay an amount per MWH equal to the hourly quoted rate agreed upon by the parties hereto prior to commencement of delivery of such energy for the next hour. The incremental cost quoted by Southern Companies for each hour (determined in accordance with the priorities established in Section 3.10.1) shall be based on the estimated incremental cost of fuel; estimated incremental maintenance cost; estimated incremental emission allowance replacement cost; estimated incremental change in system transmission losses attributable to the transaction; and other costs, directly attributable to the transaction. If Corporation elects to continue receipt of Replacement Energy during the next hour after being notified that Southern Companies, in their sole judgment, can no longer make available Replacement Energy at the quoted price, the price of such energy shall be the greater of the quoted price for such Replacement Energy or the Weighted Average Energy Rate for Corporation's pro rata share of all units (WAER) as determined in Section 6.8.

6.10 IPC Energy Rate: The rate ($/MWh) for IPC Energy supplied to Corporation pursuant to Section 3.11 will be determined in accordance with the method and procedure established for Replacement Energy under Section 6.9 hereof.

## ARTICLE VII

## BILLING AND PAYMENTS

7.1 Presentation and Payment of Bills for Capacity Charges: Capacity charges in the amounts determined in accordance with Article VI for each month shall be stated in an invoice presented by Southern Companies to Corporation on or before December 1 of each year stating the amount due each month during the ensuing year. To the extent the monthly capacity charges specified in any such invoice change as a result of causes specified in this UPS Agreement, an amended invoice shall be presented to Corporation by Southern Companies as soon as practicable after such change occurs. On or before the fifteenth day of each month of the ensuing year, Corporation shall make payment to Southern Companies in accordance with the invoice or amended invoice in immediately available funds through wiring of funds or other mutually agreeable methods of payment. Payments of capacity charges not made when due shall accrue interest, at one hundred five percent (105%) of the prime rate quoted on the date due by Manufacturers Hanover Trust Company in New York, New York, from the due date to the day of payment (a day shall equal 1/30 of a month). Any adjustment due to be made as a result of the procedure set forth in Section 2.2.18 or Article IX of the Unit Power Sale Manual shall be added to or subtracted from the invoice due to be paid in the month next following the date on which Corporation is notified by Southern Companies (by mail and telecopy on the same day) of such adjustment. Such payment shall also include any amounts theretofore invoiced by Southern Companies and not paid by Corporation associated with the administration of the true-up provision as specified in Article IX of the Unit Power Sale Manual. Payments of capacity and transmission charges which are in excess (or deficient) of amounts which would have been due based upon actual trued-up costs shall be credited (or debited) to Corporation together with interest thereon from the date payment was due on the budgeted amount to the date payment is made for credit (or debit) resulting from the true-up. Interest on the excess or deficient amount shall be accrued at one hundred percent (100%) of the prime rate quoted by Manufacturers Hanover Trust Company in New York, New York, on the date payment of the budgeted amount was due. Said prime rate shall be applicable until the next succeeding payment date, at which time interest shall accrue at one hundred percent (100%) of the prime rate quoted by Manufacturers Hanover Trust Company on the date such next succeeding payment was due. This interest accrual procedure shall be repeated monthly until such time as the excess (or deficient) amounts are credited (or debited) to Corporation.

7.2 Presentation and Payment of Bills for Energy and Other Charges: As promptly as practicable after the first of each month during the term hereof, an invoice shall be sent by Southern Companies by mail and by telecopy on the same date stating the charges determined in accordance with Article VI for energy sold and delivered to Corporation hereunder during the preceding month together with any other charges then due by Corporation to Southern Companies pursuant to the terms of this UPS Agreement. All such invoices shall be due and payable within ten (10) days from the date of mailing (as determined by postmark) by Southern Companies, or by the 20th day of the month, whichever is later. Corporation shall make payment to Southern Companies in accordance with such invoices on or before the date due in immediately available funds through wiring of funds or other mutually agreeable methods of payment. Bills not paid when due shall accrue interest, at one hundred five percent (105%) of the prime rate quoted on the due date by Manufacturers Hanover Trust Company in New York, New York, from the due date to the date of payment (a day shall equal 1/30 of a month). with each monthly invoice, Southern Companies will provide Corporation a monthly statement to show the energy transactions and the basis for the settlement pertaining thereto. including the fuel cost components of energy charges. To expedite submission of invoices, the most recently available cost data will be used for the initial invoice. An adjusted invoice, if required to reflect the actual charges due for energy, shall be included in the monthly invoice immediately following the initial invoice, together with accrued interest on overpayments (or underpayments) at one hundred percent (100%) of the prime rate as provided for in Section 7.1.

7.3 Disauted Invoice: In case any portion of an invoice submitted pursuant to Sections 7.1 and 7.2 is in bona fide dispute, the undisputed amount shall be payable when due: and the remainder shall be paid promptly, upon determination of the correct amount, in accordance with Sections 7.1 and 7.2, including interest at one hundred percent (100%) of the prime rate as provided for in Section 7.1. upon request by Corporation, Southern Companies shall provide copies of supporting documentation and records necessary to verify invoices whether disputed or undisputed.

7.4 Audit Riahts and Finalitv of Bills: Corporation shall, upon written notice, have the right to audit any and all books and records of Southern Companies which relate to and are necessary for verification of charges and costs included in invoices or amended invoices rendered under this UPS Agreement. Such audit rights shall extend for a period of three (3) calendar years prior to the calendar year in which Corporation gives written notice to Southern Companies of its intention to perform an audit or have an audit performed. All charges and costs billed or invoiced to Corporation during a subject calendar year shall become final and not subject to adjustment after the expiration of three (3) calendar years after the end of the subject calendar year if Corporation has not given written notice to Southern Companies of audit findings and any request for adjustments to bills or invoices rendered by Southern Companies during the subject calendar year (e.g., 1995 calendar year charges and cost billed or invoiced will be final if a notice and request for adjustment is not received by Southern companies by December 31, 1998). Audits shall, at the option of corporation and at Corporation's sole expense, be performed by Corporation, or a nationally recognized accounting firm experienced in utility accounting practices. Upon request, Southern Conpanies will be entitled to review the complete audit report and any supporting material.

After southern Companies have been advised by written communication of the audit findings, the Operating Representatives will be responsible for arranging meetings between representatives of the parties hereto, to discuss and resolve all audit findings in an expeditious manner. It is contemplated that any adjustments to invoices or bills as a result of the audit will be resolved within a six (6) month period from the date of receipt of written communication from corporation of the audit findings and request for billing adjustment. If the parties hereto are unable to resolve audit findings within such six (6) month period, interest on any adjustments made as the result of such audit after the close of such period shall accrue at one hundred and five percent (105%) of the prime rate quoted by Manufacturers Hanover Trust Company from the date of the receipt of written communication from corporation, instead of the one hundred percent (100%) prime interest rate provided for in Section 7.1.

In the case of internal audits or other audits performed by or far Southern Companies, any adjustments to correct previous invoices or bills rendered under this UPS Agreement shall only be permitted for a period of three (3) calendar years prior to the date Corporation is rendered an adjusted invoice or bill. Upon request, Corporation will be entitled to review the complete audit report and any supporting materials.

## ARTICLE VIII

## OPERATING COMMITTEE

8.1 Establishment of Operating Committee: Corporation and SCS, acting as agent for Southern Companies, shall each appoint one representative ("Operating Representative") to act for it in matters pertaining to detailed operating arrangements for delivery of power hereunder, and Corporation and SCS may each appoint an alternate to act for it in the absence of its Operating Representative. The two Operating Representatives, or their alternates, so appointed shall comprise and be referred to as the Unit Power Sales Operating Committee. Evidence of such appointment shall be given by written notice to each of the parties, and such appointments may be changed at any time by similar notice.

8.2 Responsibilities of the Unit Power Sales Operating Committee: The Unit Power Sales Operating Committee, in addition to matters specifically referred to elsewhere in this UPS Agreement, shall be responsible for the following:

(a) Establishment of procedure for communications with respect to energy availability and scheduling under Article 111.

(b) Establishment of arrangements for metering, telemetering, computer data link, telecommunications, data acquisition, etc., associated with the delivery and receipt of power and energy hereunder to the extent not provided for by the Operating Committee established under the Interchange Contract.

(c) Communications with respect to the construction and schedule for commercial operation of the units specified in Section 2.1.

(d) Establishment of control and operating procedures to the extent not provided for by the Operating Committee under the Interchange Contract.

(e) Establishment of methods and procedures for accounting and billing hereunder.

(f) Communications with respect to determination of capacity available from each unit under Section 2.3 including adjustments to Net Dependable Capacity as may be necessary to reflect changed conditions or anticipated conditions.

(g) Development of forecasts by month of energy availability, demand and pricing, including capacity costs for use in planning by the parties.

(h) Communications with respect to the maintenance of the units specified in Section 2.1 including the review and coordination of annual maintenance schedules for the upcoming five (5) year period.

(i) Communications with respect to minimum operating conditions when it becomes necessary to manage fuel stockpiles under Section 3.6.

(j) Such other duties as may be conferred upon it by mutual agreement of Corporation and Southern Companies.

Both Corporation and Southern Companies shall cooperate in providing to the Unit Power Sales operating Committee all information required in the performance of its duties. If the Unit Power Sales Operating Committee is unable to agree on any matter falling under its jurisdiction, such matter shall be referred by the Operating Representatives to their principals for decision. Failure of the principals to agree on any matter referred to them shall not constitute a basis for cancellation of this UPS Agreement. All decisions and agreements made by the Unit Power sales Operating Committee shall be evidenced in writing.

8.3 Unit Power Sales Operating Committee Meetings: The Unit Power Sales Operating'Committee shall hold an annual meeting at a time and place agreed upon by its members and review the duties set forth herein. When requested by either Corporation or Southern Companies, the Unit Power Sales Operating Committee shall also meet at the earliest opportunity for consideration of matters under its jurisdiction.

ARTICLE IX

AGENCY OF SOUTHERN COMPANY SERVICES. INC. FOR SOUTHERN COMPANIES

9.1 Role of SCS: SCS joins in the execution of this Agreement for the sole purpose of serving and acting as agent for Southern Companies jointly and severally. Southern Companies may designate a new agent from time to tine under this UPS Agreement by giving Corporation ten (10) days' written notice in which event the authority of SCS, as agent, shall cease and the newly designated agent shall be substituted for the sole purpose of serving and acting as agent for Southern Companies jointly and severally.

9.2 Payments and Notices to Aoent: Corporation shall be entitled to make all payments due to be made in accordance with this UPS Agreement to SCS, or such other agent of Southern Companies as designated under Section 9.1, and the making of such payments shall discharge Corporation's obligation hereunder notwithstanding the fact that such payments shall be due to be paid to one or more of Southern Companies. Corporation shall be entitled to make any notices provided for in this UPS Agreement to the Vice President-Operating and Planning Services of SCS or such other person as Southern Companies may designate.

ARTICLE X

MISCELLANEOUS **PROVISIONS**

10.1 Interrelationship with Interchanae Contract: It is recognized by the parties hereto that the Interchange Contract as of the date hereof governs the interconnected operations of the parties hereto necessary for conduct of the transactions contemplated hereunder. To the extent not inconsistent herewith, such Interchange Contract, including any amendments thereto, shall govern the operations of the parties hereunder. In the event such Interchange Contract is terminated or cancelled during the term of this UPS Agreement, the provisions of such Interchange Contract which are essential for the continuation of transactions hereunder shall survive the termination or cancellation of such Interchange Contract.

10.2 provisions of Interchanae Contract Specifically Incorporated bv Reference: The parties hereto agree that the following provisions of the Interchange Contract are specifically incorporated herein by reference as though fully set forth herein:

(a) Section 5.4 Kilovar Supply.

(b) Section 5.5 Determination of Amounts of Power Supplied.

(c) Section 6.2 Metering and Meterina Facilities.

(d) Section 6.3 Inspecting and Testinu of Meters.

(e) Section 7.1 Records.

(f) Section 9.5 Third Parties.

(g) Section 10.5 Waivers.

(h) Section 10.6 Successors and Assians.

10.3 Specification of Sole Obliaation or Sole Remedy: With respect to the matters provided for herein where this UPS Agreement specifies an obligation or remedy as being the sole obligation or remedy, it is the agreement and intent of the parties hereto that such obligation or such remedy is the exclusive obligation or remedy. No expansion of such obligation or remedy shall be provided in any suit, action or proceeding of any nature whatsoever, whether the claim underlying such suit, action or proceeding is based on contract, tort (including strict liability) or otherwise.

10.4 Standard of Performance of Obligations: In connection with the operation and maintenance of units from which Corporation is entitled to capacity, other facilities (including transmission) referenced in this UPS Agreement and other facilities required in support of Southern Companies' obligations under this UPS Agreement, Southern Companies' standard of management and performance during the term of this UPS Agreement shall be at least equal to the standard which they would use if such units and facilities were solely for their own territorial customers.

10.5 **Definition of "Prudent Utility Practices":** For purposes of this UPS Agreement, "Prudent Utility Practices" at a particular time shall mean any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry prior to such time, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. "Prudent Utility Practices" are not intended to be limited to the optimum practice, method or act to the exclusion of all others, but rather to be a spectrum of possible practices, methods or acts expected to accomplish the desired results.

10.6 Limitation of Liability: In no event shall any party hereto be liable (in contract or in tort, including negligence) to any other party hereto for incidental or consequential loss or damage resulting from performance, nonperformance or delay in performance of obligations under this UPS Agreement, except where such loss or damage results from intentional tort or fraud.

10.7 General Cost Principles: Charges for electric services provided for in this UPS Agreement consist of and include both direct and indirect costs incurred by Southern companies attributable to activities required for the construction, operation and maintenance of transmission and generation facilities necessary to meet their obligations hereunder. Corporation and Southern Companies have agreed upon certain formulary descriptions of methodology and procedure as contained in the Unit Power Sale Manual and this UPS Agreement which shall be used in computation of charges.

It is recognized that the derivation and computation of such charges will include costs both directly and indirectly incurred by Southern Companies and that in the case of costs indirectly incurred it will be necessary to apply certain allocation methods and procedures to assign such costs to the appropriate facilities.' Such costs shall be allocated by using the allocation methods and procedures set forth in the

Unit Power Sale Manual. If no allocation methods or procedures have been specified herein for a particular cost or cost component, Southern Companies shall apply fair and equitable allocation methods and procedures consistent with Prudent Utility Practices. Further, Southern Companies agree to notify corporation of such newly-developed allocations or procedures and the parties hereto will make a good faith effort to agree with such allocations or procedures within a six (6) monrh period following notification to Corporation. If the parties hereto are unable to agree within such six (6) month period, the matter will be referred to the Operating Representatives in accordance with Section 8.2.

It is the intent of the parties hereto that the accounting for Southern Companies' costs, both direct and indirect, and allocations thereof shall be pursuant to assessing actual costs incurred, and charges to Corporation shall not include duplication or allocations of greater than one hundred percent (100%) of such costs.

10.8 Section References: References herein to articles shall be interpreted to mean all sections of the article referenced. References to sections shall be interpreted to mean all subsections of the section referenced.

10.9 Equal Employment Opportunity and Civil Rights: The parties hereby certify that they will comply with Section 202, Paragraphs 1 through 7 of Executive Order 11246, as amended, and applicable portions of Executive Orders 11701 and 11758, relative to Equal Employment Opportunity and the Implementing Rules and Regulations of the Office of Federal Contracts Compliance which are incorporated herein by this reference.

10.10 Contemporaneous Parties Defined: For purposes of this UPS Agreement, contemporaneous parties will mean Florida Power & Light Company ("FPL") and/or Jacksonville Electric Authority ("JEA") if either or both of those utilities execute new unit power sales contracts for the purchase of capacity from the units specified in Section 2.1 within forty-five (45) days of the execution of this UPS Agreement. Execution by JEA shall mean upon approval and acceptance by the Jacksonville Electric Authority Board but shall not mean final approval by the City Council of Jacksonville. It is understood that FPL and JEA have existing unit power sale contracts with Southern Companies (executed in 1982) and that Corporation will not be considered as a contemporaneous party with respect to those existing contracts. The term "contemporaneous parties" as used in this UPS Agreement may include Corporation, FPL and JEA if the context so indicates and the above conditions are satisfied. The term "other contemporaneous parties" as used in this UPS Agreement will include FPL and JEA if the context so indicates and the above conditions are satisfied.

10.11 Additional Riahts: Except as to differences (including but not limited to amount of capacity purchased and time periods of purchases) selected by the contemporaneous parties in initial unit power sales contracts, Southern Companies will offer any revisions or changes to the initial contracts (including but not limited to the return on equity, early options and associated Long Term Power sales) **to** all contemporaneous parties on non-discriminatory terns, conditions and rights. It is recognized, however, that the contemporaneous parties may exercise their early options in different amounts and time periods and that the exercise of such options can result in capacity and energy cost differences between the contemporaneous parties. If either of the other contemplated contemporaneous parties fails to execute a contemporaneous unit power sales contract but later (before June 1,1995) executes a contract to purchase unit power, Southern Companies will offer to amend this **UPS** Agreement to insure that it contains equal and non-discriminatory terms, conditions and rights.

10.12 other Agreements: The parties hereto agree that this **UPS** Agreement, together with all exhibits and attachments hereto, constitute **a** contractual arrangement and agreement separate from and independent of all other existing agreements between the Southern Companies and Corporation.

10.13 Notices bv Southern Companies: Southern Companies shall be entitled to make any notices provided for in this **UPS** Agreement to the Vice President - System Operations of Corporation or such other person as Corporation may designate.

10.14 Responsibility and Indemnification: With regard to transactions pursuant to this **UPS** Agreement, each party hereto agrees to operate and maintain its electrical equipment with reasonable diligence and care and in accordance with Prudent Utility Practices. Corporation and Southern Companies expressly agree to indemnify and save harmless and defend the other against all claims, demands, costs, or expense for loss, damage or injury to persons or property, in any manner directly or indirectly connected with or growing out of the generation, transmission, or use of electric capacity and energy on its own side of the delivery point or points hereunder, irrespective of negligence actual or claimed of the other. It is the intention of the parties to this UPS Agreement that each of them be responsible for their own conduct and neither be responsible for the conduct of the other. This UPS Agreement in no way creates a contractual relationship of one party with the customers of the other party; neither does it create a duty thereto.

[The next page is the signature page, page 41.]

IN WITNESS WHEREOF, the parties hereto have caused this UPS Agreement to be executed by their duly authorized officers effective as of the date set forth in Section 1.1.

FLORIDA POWER CORP. LEGAL DEPT. APPROVED Date 7-15-88 By

| | |
|---|---|
| ATTEST: | FLORIDA POWER CORPORATION |
| Kathleen P. Kortright | By B. L. Griffin |
| Assistant Secretary | B. L. Griffin, Exec. Vice President |
| | Date: July 14, 1988 |
| ATTEST: | SOUTHERN COMPANY SERVICES, INC. |
| Wayne Boston | By R. O. Usry |
| Asst Secretary | R. O. Usry, Vice President |
| | Date: July 19, 1988 |
| ATTEST: | ALABAMA POWER COMPANY |
| Wayne Boston | By R. E. Huffman |
| Asst Secretary | R. E. Huffman, Vice President |
| | Date: July 19, 1988 |
| ATTEST: | GEORGIA POWER COMPANY |
| Wayne Boston | By Fred D. Williams |
| Asst Secretary | Fred D. Williams, Vice President |
| | Date: July 19, 1988 |
| ATTEST: | GULF POWER COMPANY |
| Wayne Boston | By Earl B. Parsons Jr. |
| Asst Secretary | E. B. Parsons, Jr., Vice President |
| | Date: July 19, 1988 |
| ATTEST: | MISSISSIPPI POWER COMPANY |
| Wayne Boston | By Robert C. Pierce |
| Asst Secretary | Robert C. Pierce, Vice President |
| | Date: July 19, 1988 |
| ATTEST: | SAVANNAH ELECTRIC AND POWER COMPANY |
| Wayne Boston | By H. W. Kraft |
| Asst Secretary | H. W. Kraft, Vice President |
| | Date: July 19, 1988 |

EXHIBIT A Page 1

ALLOCATION OF EXPECTED CAPACITY
FOR UNIT POWER SALES TO CORPORATION
UNDER THIS UPS AGREEMENT
(MW)

| Year | Period | ALABAMA POWER COMPANY (APC) Mil 1 | Mil 2 | Mil 3 | Mil 4 | APC Total | GEORGIA POWER COMPANY (GaPC) Scherer 3 | GULF POWER COMPANY (GuPC) Scherer 3 | | Total |
|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | - | - | - | - | - | - | - | | - |
| | Jun-Dec | - | - | - | - | - | - | - | | - |
| 1994 | Jan-May | 58 | 58 | 58 | - | 174 | 8 | 18 | 26 | 200 |
| | Jun-Dec | 41 | 40 | 40 | 41 | 162 | 13 | 25 | 38 | 200 |
| 1995 | Jan-May | 85 | 85 | 85 | 85 | 340 | 20 | 40 | 60 | 400 |
| | Jun-Dec | 80 | 80 | 80 | 80 | 320 | 26 | 54 | 80 | 400 |
| 1996 | Jan-Dec | 80 | 80 | 80 | 80 | 320 | 26 | 54 | | 400 |
| . | . | . | | | | | | . | | . |
| | | | | | | | | . | | . |
| | | | | | | | | . | | . |
| 2010 | Jan-May | 80 | 80 | 80 | 80 | 320 | 26 | 54 | | 400 |
| | Jun-Dec | - | - | - | - | - | - | - | | - |

TOTAL CAPACITY AVAILABLE TO CORPORATION
AND OTHER CONTEMPORANEOUS PARTIES
TO MEET THE EARLY OPTIONS
(MW)

| Year | Period | ALABAMA POWER COMPANY (APC) Mil 1 | Mil 2 | Mil 3 | Mil 4 | APC Total | GEORGIA POWER COMPANY (GaPC) Scherer 3 | GULF POWER COMPANY (GuPC) Scherer 3 | Total |
|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | 453 | 453 | 453 | - | 1359 | 106 | 35 | 1500 |
| | Jun-Dec | 300 | 300 | 300 | - | 900 | 209 | 16 | 1125 |
| 1994 | Jan-May | 247 | 246 | 247 | - | 740 | 169 | 16 | 925 |
| | Jun-Dec | 140 | 140 | 140 | 140 | 560 | 106 | 34 | 700 |
| 1995 | Jan-May | 100 | 100 | 100 | 100 | 400 | 66 | 34 | 500 |

Notes: Mil 1 - Hiller 1, "Expected Capacity": 666 MW
Mil 2 - Miller 2, "Expected Capacity": 666 MW
Mil 3 - Miller 3, Expected Commercial Operation 5-1-89,
"Expected Capacity": 666 MW
Mil 4 - Miller 4, Expected Commercial Operation 3-15-91,
"Expected Capacity": 666 MW
Scherer 3 "Expected Capacity": 808 MW

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Governing Examples for Interpretation of Early Option
Under Section 2.2.1

EXHIBIT A P g 2

**Example 1**

FPL, JEA, and Corporation give proper notice to exercise the full amounts of their respective early options beginning 1/1/93. The capacity for such early options will be taken from the designated units in the amounts shown below:

**Florida Power & Light Company**

| Year | Period | Mil 1 | Mil 2 | APC Mil 3 | Mil 4 | APC Total | GaPC Scherer 3 | GuPC Scherer 3 | Scherer 3 Total | UPS Advanced Total by FPL | Total Advanced by All Contemporaneous Parties | FPL Percent of Total Advanced | One Fifth Of UPS Advanced By FPL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | 272 | 271 | 272 | - | 815 | 64 | 21 | 85 | 900 | 1500 | 60.0% | 180 |
| | Jun-Dec | 160 | 160 | 160 | - | 480 | 112 | 8 | 120 | 600 | 1125 | 53.3% | 120 |
| 1994 | Jan-May | 160 | 160 | 160 | - | 480 | 110 | 10 | 120 | 600 | 925 | 64.9% | 120 |
| | Jun-Dec | 90 | 90 | 90 | 90 | 360 | 68 | 22 | 90 | 450 | 700 | 64.3% | 90 |
| 1995 | Jan-May | 90 | 90 | 90 | 90 | 360 | 59 | 31 | 90 | 450 | 500 | 90.0% | 90 |

**Jacksonville Electric Authority**

| Year | Period | Mil 1 | Mil 2 | APC Mil 3 | Mil 4 | APC Total | GaPC Scherer 3 | GuPC Scherer 3 | Scherer 3 Total | UPS Advanced Total by JEA | Total Advanced by All Contemporaneous Parties | JEA Percent of Total Advanced | One Fifth Of UPS Advanced By JEA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | 60 | 61 | 60 | - | 181 | 14 | 5 | 19 | 200 | 1500 | 13.3% | 40 |
| | Jun-Dec | 33 | 34 | 33 | - | 100 | 23 | 2 | 25 | 125 | 1125 | 11.1% | 25 |
| 1994 | Jan-May | 33 | 33 | 34 | - | 100 | 23 | 2 | 25 | 125 | 925 | 13.5% | 25 |
| | Jun-Dec | 10 | 10 | 10 | 10 | 40 | 8 | 2 | 10 | 50 | 700 | 7.1% | 10 |
| 1995 | Jan-May | 10 | 10 | 10 | 10 | 40 | 7 | 3 | 10 | 50 | 500 | 10.0% | 10 |

**Florida Power Corporation**

| Year | Period | Mil 1 | Mil 2 | APC Mil 3 | Mil 4 | APC Total | GaPC Scherer 3 | GuPC Scherer 3 | Scherer 3 Total | UPS Advanced Total by Corporation | Total Advanced by All Contemporaneous Parties | Corporation Percent of Total Advanced | One Fifth Of UPS Advanced by Corporation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | 121 | 121 | 121 | - | 363 | 28 | 9 | 37 | 400 | 1500 | 26.7% | 80 |
| | Jun-Dec | 107 | 106 | 107 | - | 320 | 74 | 6 | 80 | 400 | 1125 | 35.6% | 80 |
| 1994 | Jan-May | 54 | 53 | 53 | - | 160 | 36 | 4 | 40 | 200 | 925 | 21.6% | 40 |
| | Jun-Dec | 40 | 40 | 40 | 40 | 160 | 30 | 10 | 40 | 200 | 700 | 28.6% | 40 |
| 1995 | Jan-May | - | - | - | - | - | - | - | - | - | 500 | - | - |

Governing Examples for Interpretation of Early Option
Under Section 2.2.1

EXHIBIT A Page 3

Example 2
FPL gives proper notice to exorcise its early option for the Cull 900 MW beginning 1/1/91. Neither of the other contemporaneous parties exercises any portion of its early options. The capacity for FPL's marly option will be taken from the designated units in tho amounts shown below:

Florida Power & Light Company

| ~~Year Period~~ | | nil I | Mil 2 | APC nil 3 | nil 4 | Arc Total | GaPC Scherer I | GUPC Scherer ~~3~~ | Scherer 3 ~~Total~~ | UPS Advanced Total by FPL | Total Advanced by All Contemporaneous Parties | FPL Percent of Total Advanced | One Fifth Of UPS Advanced By FPL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-nay | 253 | 253 | 251 | - | 159 | 106 | 35 | 141 | 900 | 900 | 100.0% | 180 |
| | Jun-Dec | 160 | 160 | 160 | - | 480 | 104 | 16 | 120 | 600 | 600 | 100.01 | 120 |
| 1994 | Jan-May | 160 | 160 | 160 | - | 480 | 104 | 16 | 120 | 600 | 600 | 100.01 | 120 |
| | Jun-Dec | 90 | 90 | 90 | 90 | 360 | 56 | 34 | 90 | 450 | 450 | 100.0% | 90 |
| 1995 | Jan-nay | 90 | 90 | 90 | 90 | 360 | 56 | 34 | 90 | 450 | 450 | 100.01 | 90 |

Jacksonville Electric Authority

| ~~Year Period~~ | | Mil 1 | nil 2 | APC Mil 3 | Mil 4 | Arc Total | GaPC Scherer 3 | GuPC Scherer ~~3~~ | Scherer 1 ~~Total~~ | UPS Advanced Total by JEA | Total Advanced by All Contemporaneous Parties | JEA Percent of Total Advanced | On Fifth Of UPS Advanced By JEA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1991 | Jan-Hay | - | - | - | - | - | - | - | - | - | 900 | - | - |
| | Jun-Dec | - | - | - | - | - | - | - | - | - | 600 | - | - |
| 1994 | Jan-Hay | - | - | - | - | - | - | - | - | - | 600 | - | - |
| | Jun-Dec | - | - | - | - | - | - | - | - | - | 450 | - | - |
| 1995 | Jan-May | - | - | - | - | - | - | - | - | - | 450 | - | - |

Florida Power Corporation

| Year | Period | Mil ~~1~~ | nil ~~2~~ | APC Mil ~~3~~ | Mil ~~4~~ | APC ~~Total~~ | GaPC Scherer 3 | GuPC Scherer 3 | Scherer 1 Total | UPS Advanced Total by Corporation | Total Advanced by All Contemporaneous Parties | Corporation Percent of Total Advanced | One Fifth Of UPS Advanced by Corporation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | - | - | - | - | - | - | - | - | - | 900 | - | - |
| | Jun-Dec | - | - | - | - | - | - | - | - | - | 600 | - | - |
| 1994 | Jan-Hay | - | - | - | - | - | | | | | 600 | | |
| | Jun-Dec | - | - | - | - | - | - | - | | - | 450 | | |
| 1995 | Jan-May | - | - | - | - | - | | | | - | 450 | - | |

Governing Examples for Interpretation of Early Option
Under Section 2.2.1

EXHIBIT A Page 4

Example 3
FPL gives proper notice to exercise its early option for the full 900 MW beginning 1/1/93. Corporation gives proper notice to exercise 100 MW of its early option beginning 1/1/94 through 12/31/94. JEA gives proper notice to exercise 50 MW of its early option beginning 6/1/94 through 5/31/95. The capacity for such early options will be taken from the designated units in the amounts shown below:

Florida Power & Light Company

| Year | Period | Mil 1 | Mil 2 | APC Mil 3 | Mil 4 | APC Total | GaPC Scherer 3 | GuPC Scherer 3 | Scherer 3 Total | UPS Advanced Total by FPL | Total Advanced by All Contemporaneous Parties | FPL Percent of Total Advanced | One Fifth Of UPS Advanced By FPL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | 253 | 253 | 253 | - | 759 | 106 | 35 | 41 | 900 | 900 | 100.0% | 180 |
| | Jun-Dec | 160 | 160 | 160 | - | 480 | 104 | 16 | 20 | 600 | 600 | 100.0% | 120 |
| 1994 | Jan-May | 160 | 160 | 160 | - | 480 | 106 | 14 | 20 | 600 | 700 | 85.7% | 120 |
| | Jun-Dec | 90 | 90 | 90 | 90 | 360 | 65 | 25 | 90 | 450 | 600 | 75.0% | 90 |
| 1995 | Jan-May | 90 | 90 | 90 | 90 | 360 | 59 | 31 | 90 | 450 | 500 | 90.0% | 90 |

Jacksonville Electric Authority

| Year | Period | Mil 1 | Mil 2 | APC Mil 3 | Mil 4 | APC Total | GaPC Scherer 3 | GuPC Scherer 3 | Scherer 3 Total | UPS Advanced Total by JEA | Total Advanced by All Contemporaneous Parties | JEA Percent of Total Advanced | One Fifth Of UPS Advanced By JEA |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | - | - | - | - | - | - | - | - | - | 900 | - | - |
| | Jun-Dec | - | - | - | - | | - | - | - | - | 600 | - | - |
| 1994 | Jan-May | - | - | - | - | | - | - | - | - | 700 | - | - |
| | Jun-Dec | 10 | 10 | 10 | 10 | 40 | 7 | 3 | 10 | 50 | 600 | 8.3% | 10 |
| 1995 | Jan-May | 10 | 10 | 10 | 10 | 40 | 7 | 3 | 10 | 50 | 500 | 10.0% | 10 |

Florida Power Corporation

| Year | Period | Mil 1 | Mil 2 | APC Mil 3 | Mil 4 | APC Total | GaPC Scherer 3 | GuPC Scherer 3 | Scherer 3 Total | UPS Advanced Total by Corporation | Total Advanced by All Contemporaneous Parties | Corporation Percent of Total Advanced | One Fifth Of UPS Advanced by Corporation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1993 | Jan-May | - | - | - | - | - | - | - | - | - | 900 | - | - |
| | Jun-Dec | - | - | - | - | - | - | - | - | - | 600 | - | - |
| 1994 | Jan-May | 27 | 26 | 27 | - | 80 | 18 | 2 | 20 | 100 | 700 | 14.3% | 20 |
| | Jun-Dec | 20 | 20 | 20 | 20 | 80 | 14 | 6 | 20 | 100 | 600 | 16.7% | 20 |
| 1995 | Jan-May | - | - | - | - | - | - | - | - | - | 500 | - | - |

EXHIBIT C

UNIT POWER SALE MANUAL

Section C0.0 Description and Purpose of Unit Power Sale Manual: This Unit Power Sale Manual contains a formulary description of the methodology and procedure used to calculate the charges for each Contract Year for the unit power sales provided for in the UPS Agreement and is attached to the UPS Agreement between Corporation and Southern Companies. Contract Year shall be defined to be the calendar year for which charges for unit power sales are being established. The Unit Power Sale Manual is divided into nine (9) basic articles as follows:

| | |
|---|---|
| Article I | - Derivation of Net Dependable Capacity Ratings for Electric Generating Units |
| Article II | - Derivation of Capacity Charge for Coal-Fired Electric Generating Units |
| Article III | - Derivation of Capacity Charge for Transmission Facilities |
| Article IV | - Derivation of Fuel Costs and Normalized Fuel Costs for Electric Generating Units |
| Article V | - Derivation of Fixed Operation and Maintenance and variable Operation and Maintenance Expenses for Electric Generating Units |
| Article VI | - Derivation of Return on Common Equity |
| Article VII | - Derivation of Average Transmission Loss Percentages |
| Article VIII | - Unit Power Sale Informational Schedule and Support Schedules and Monthly Report of Energy Transactions |
| Article IX | - Adjustments for Actual cost |

Section C0.1 Allocation Methods and Procedures: The allocation methods and procedures set forth in this Unit Power Sale Manual have been developed with reference to Southern Companies present accounting practices; if such accounting practices change in the future so as to make the allocation methods and procedures specified in this Unit Power Sale Manual inappropriate, the allocation methods and procedures shall be deleted or changed to meet the new accounting practices of Southern Companies, provided such changed allocation methods and procedures are fair and equitable.

<u>Section C0.2 "Uniform System of Accounts"</u>: The FERC Accounts set forth in this Unit Power Sale Manual are currently prescribed in FERC's "Uniform System of Accounts Prescribe; for Public Utilities and Licensees (Class A and Class B)" in effect as of the date of the UPS Agreement. If these FERC Accounts are amended, then this Unit Power Sale Manual shall be construed to reflect the amended accounts prescribed by FERC or its successor agency.

ARTICLE I

DERIVATION OF NET DEPENDABLE CAPACITY
RATINGS FOR ELECTRIC GENERATING UNITS

This article of this Unit Power Sale Manual establishes the definition and methodology for the yearly derivation of Net Dependable Capacity ratings used in the computation of capacity charges and for such other purposes as specified in the UPS Agreement. The definition and methodology for the derivation of Net Dependable Capacity ratings specified in this article are also used in the computation of capacity charges in other contracts of Southern Companies, including contracts with third parties and between one operating company of Southern Companies and another operating company of Southern Companies. Southern Companies may be referred to individually as an "operating company".

Section C1.0 Net Dependable Capacity: For the purpose of deriving the Net Dependable Capacity of each electric generating unit for the ensuing Contract Year, the net generation in kilowatt hours (kWh) of each unit will be determined for the highest four (4) continuous hours during the peak-period hours (with peak-period defined to be the eight (8) hours between 11:00 a.m. and 7:00 p.m. prevailing Central Time of each weekday, excluding holidays) without overpressure, for five (5) different days during June, July and August of the calendar year preceding the Contract Year. The Net Dependable Capacity of a unit for the Contract Year is defined as the average of the net generation for such twenty (20) hours, subject to the principles in Sections C1.1 and C1.2 below. Southern Companies will use best efforts, consistent with Prudent Utility Practice, to maximize the Net Dependable Capacity rating for each unit.

Section C1.1 Adjustments for Unusual Circumstances: In the event unusual circumstances occur during the months of July and August in the calendar year preceding the Contract Year (or June, July, and August as per the then current practice of Southern Companies in rating their generating units for intercompany use) or circumstances during the Contract Year are expected to be significantly different from those during such July and August (or June, July, and August as per the then current practice of Southern Companies in rating their generating units for intercompany use), in the sole opinion of the operating company responsible for operating the unit, such operating company will determine the Net Dependable Capacity for such unit for the Contract Year and will provide a statement giving the reason(s) for not using the value for Net Dependable Capacity determined in Section C1.0 and the method used to establish the Net Dependable Capacity for the Contract Year.

Section C1.2 Units Being Declared Commercial: The Net Dependable Capacity for a unit declared commercial after the month of August in the calendar year preceding the Contract Year will be determined from the turbine manufacturer's design gross generation capability at valves wide open, adjusted for station service and further adjusted by the historical ratio of Net Dependable Capacity to design generation capability for similar units on the systems of Southern Companies.

Section C1.3 Data to Be Provided: The data used in the determination of the Net Dependable Capacity for each unit each contract Year, pursuant to Sections C1.0, C1.1, and c1.2 above, will be provided to purchasers of unit power in accordance with Article VIII of this Unit Power Sale Manual.

# ARTICLE II

## DERIVATION OF CAPACITY CHARGE FOR COAL-FIRED ELECTRIC GENERATING UNITS

This article of this Unit Power Sale Manual establishes the formulary methodology for deriving capacity cost and charges related to coal-fired electric generating units dedicated to unit power sales under the UPS Agreement. The formulary methodology will be used to derive both estimated capacity cost for preliminary billing and actual capacity cost for corrections to such preliminary billing.

Section C2.1 Capacitv Cost of Unit Power Sales: The computation of the capacity cost of unit power sales for each month of the Contract Year will be accomplished in the following manner. The monthly capacity cost ($/kW-month) of each coal-fired electric generating unit participating in the unit power sales is multiplied by the portion (MW) of the unit applicable to the sale in each month to obtain the total monthly capacity dollars ($). The total monthly unit power sales capacity dollars are then summed and to this sum will be added an amount equal to the total MW applicable to the unit power sales multiplied by an amount (fixed at a rate of $0.08/kW-month), as agreed to by the parties hereto, to compensate for scheduling, coordination and other difficult-to-quantify cost applicable to the transactions under the UPS Agreement. This capacity cost for each month will constitute the charge for capacity sold by Southern Companies under the UPS Agreement. This charge for each month of the first Contract Year will be shown on the Unit Power Sale Informational Schedule, and will be revised in accordance with this Unit Power Sale Manual in subsequent calendar years.

Section C2.2 Derivation of Estimated Monthly Capacitv Charge of Coal-Fired Electric Generating Units: The derivation of the estimated monthly capacity charge of the coal-fired electric generating units participating in the unit power sales is based on the capacity (determined in Article I of this Unit Power Sale Manual) and the projected investments and expenses related to production and generator step-up substation facilities of each such unit during the Contract Year. The derivation of the monthly capacity charge of each applicable unit is expressed in the following formula:

$$\left[\frac{I \times ((CM + IT)/100) + E}{C \times 12}\right] \left[\frac{100}{100 - L_c}\right]$$

where:

R = Monthly production capacity charge for operating company owned capacity ($/kW-month).

I = Total of the net investment associated with the operating company's portion of the unit ($).

CM = The weighted average cost of capital associated with the operating company's cost of construction of the unit (%).

IT = ?he income tax requirement associated with the preferred stock and common equity weighted cost of capital associated with the operating company's cos': of construction of the unit (%).

E = Total of the annualized fixed expenses associated with the operating company's portion of the unit ($).

C = Net Dependable Capacity of the operating company's portion of the generating unit (kW).

$L_c$ = Average transmission capacity loss percentaye of Southern Companies as determined in Article VII of this Unit Power Sale Manual (%).

The source of the capacity, investment, and expense data incorporated in the above formula for coal-fired electric generating units (including FERC Account numbers and description of allocation procedures and calculation of the cost of capital) is as follows:

<u>Section C2.2.1: Net Dependable Capacity</u> is the rating in kw of the coal-fired electric generating unit as determined in Article I of this Unit Power Sale Manual. The value of "C" in Section C2.2 is determined by multiplying the percent ownership of the operating company by the unit's Net Dependable Capacity.

<u>Section C2.2.2: Gross Generating Unit Investment</u> for a unit owned by an operating company is the book cost of the coal-fired electric generating unit and its associated generator step-up substation. The cost of these facilities is recorded in FERC Accounts 310-316 for the generating unit and FERC Accounts 352 and 353 for the step-up substation at the end of each month of the Contract Year. The amount of booked Allowance for Funds Used During Construction ("AFUDC") shall have added to it an amount to .reflect the effect of Construction Work In Progress ("CWIP") in retail rate base. The amount of AFUDC to be added, if any, shall be calculated on a monthly basis for the construction period of the unit using the following formulae:

DA = Σ((AR - BR) x AB]

DA = Dollar amount to be added to booked AFUDC.

AR = The monthly AFUDC rate prescribed by the applicable state public service commission.

BR = The actual monthly AFUDC rate applied by the operating company (this rate being affected by CWIP in the operating company's retail rate base).

**AB** = The actual monthly AFUDC base used by the operating company in computing booked AFUDC.

All coal properties and coal handling equipment that are recorded at the end of each month of the Contract Year in FERC Accounts 389, 398, and 399 that are directly associated with the generating unit are included in the gross generating unit investment summation. Where allocations to the generating unit are required, such allocations shall be based on the usage of the property and equipment.

The common facilities of the plant site and the step-up substation yard are allocated equally among the units at the plant site.

Section C2.2.3: Accumulated Depreciation is associated with the gross production investment defined in Section C2.2.2. The accumulated depreciation for generating units is adjusted to include the amount of AFUDC determined in Section C2.2.2. If the depreciation records of the operating company do not allow for the identification of the accumulated depreciation of the specific coal-fired unit's step-up substation, a portion of the accumulated depreciation associated with the transmission plant will be allocated to the unit's generator step-up substation. The amount allocated to the generator step-up substation facilities will be on the basis of the ratio of the gross investment in the generator step-up substation facilities to the total gross investment in the transmission function excluding land.

Section C2.2.4: Net Generating Unit Investment is the difference between Section C2.2.2 (Gross Generating Unit Investment) and Section C2.2.3 (Accumulated Depreciation).

Section C2.2.5: General Plant (Net) includes the investment in FERC Accounts 389 through 399 at the end of each month of the Contract Year, excluding amounts directly assigned to production as listed in Sections C2.2.2 and C2.2.3. Net general plant, excluding the direct assignments, is allocated to the specific coal-fired generating unit and its generator step-up substation on the basis of salaries and wages as described in Section C2.2.17.

Section C2.2.6: Working Capital is the summation of cash working capital, prepayments, deposits (if any), and materials and supplies, and is computed for each month of the Contract Year.

The cash working capital for the specific coal-fired generating unit is calculated by taking one-eignth (45/360) of the sum of the annualized operating and maintenance (O&M)[1] expenses (including fuel burn) and administrative and general (A&G) expenses. The fixed O&M expense is developed in Section C2.2.9 and the A&G expense is developed in Section C2.2.10. The cash working capital for the specific unit's generator step-up substation is calculated by taking one-eighth (45/360) of the sum of the annualized fixed O&M and A&G expenses. The fixed O&M and A&G expenses are developed in Sections C2.2.9 and C2.2.10, respectively.

Prepayments are computed on the basis of a thirteen (13) month average and are directly assigned to production, transmission, general plant functions, and the specific coal-fired generating unit. The amount assigned to the transmission function is allocated to the specific coal fired unit's generator step-up substation on the basis of net transmission investment less land. prepayments associated with general plant are allocated to the specific coal-fired generating unit and its step-up substation on the basis of salaries and wages as described in Section C2.2.17.

Materials and supplies are computed on the basis of a thirteen (13) month average and consist of two parts: (i) fuel stock recorded in FERC Account 151, and (ii) plant materials and operating supplies recorded in FERC Account 154 that are related to the production function and the transmission function. The fuel stock recorded in FERC Account 151 is allocated to the specific unit at the plant site based upon the nameplate ratings of the respective units. The plant materials and operating supplies, FERC Account 154, if not directly identifiable with the plant and associated generator step-up substation, are allocated to the specific coal-fired generating unit and its associated generator step-up substation on the basis of the ratio of the respective gross investment of the specific coal-fired generating unit and its associated generator step-up substation to the gross investment in the fossil steam production function and the associated generator step-up substations. The plant material and operating supplies, FERC Account 154, directly identifiable with the plant are allocated equally among the units.

Deposits are included as working capital requirements to reflect the operating agreements that exist between one operating company and another operating company for the operation of jointly owned generating units. It should be

1. O&M expenses as used in this Unit Power Sale Manual do not include A&G expenses.

noted that while these deposits increase the working capital requirements of one operating company, they have a corresponding reduction in the working capital requirements of the other operating company.

Section C2.2.7: Accumulated Deferred Income Taxes are developed for each applicable generating unit for each month of the Contract Year and is the net total of FERC Accounts 190, 281, 282 and 283, including amounts previously recorded in such accounts and reclassified as a result of the adoption of SFAS No. 109, and excluding amounts recorded in such accounts as a result of the adoption of SFAS No. 109, such that the required adoption of SFAS No. 109 will have no impact on the amount of the capacity charge. Accumulated deferred income taxes related to general plant for both the generating unit and its step-up substation are allocated in accordance with the general plant assignments €or the unit and its step-up substation described in Section C2.2.5. The accumulated deferred income taxes related to transmission plant are allocated to the specific coal-fired unit's generator step-up substation on the basis of net investment in coal-fired unit's generator step-up substation facilities to total transmission net investment excluding land.

Section C2.2.8: Total Net Generating Unit Investment represents the direct and allocated investments that are associated with the coal-fired electric generating unit and its generator step-up substation facilities and is the summation of Section C2.2.4 (Net Generating Unit Investment) through Section C2.2.7 (Accumulated Deferred Income Taxes) and is the value for "I" for capacity in the formula in Section C2.2 for each applicable generating unit.

Section C2.2.9: Fixed Operation and Maintenance Expense is the total of the fixed expenses associated with the coal-fired electric generating unit recorder in FERC Accounts 500 through 514, excluding 501. The definition of fixed and variable as defined in these FERC Accounts is shown in Article V of this Unit Power Sales Manual. the O&M expenses in FERC Accounts 562, 569, and 570 associated with the generator step-up substation facilities of such generating unit are added to the generating unit's fixed expenses. where O&M expenses of the generator step-up facilities are not directly identifiable, they will be allocated on the basis of the ratio of the gross investment in the specific coal-fired unit's generator step-up substation to the total gross substation investment.

Section C2.2.10: Administrative and General Expenses, FERC Account 920 through 935, excluding FERC Account 924 (Property Insurance), are allocated to the specific coal-fired generating unit and its step-up substation based upon salaries and wages as described in Section C2.2.17. The property insurance is developed and assigned to the specific coal-fired generating unit. The property insurance specifically assigned to the transmission function is allocated to the unit's step-up substation based upon the net transmission investment excluding land.

Secrion C2.2.11: Depreciation Expense for the coal-fired electric generating unit is based on straiaht line depreciation with the exception of the Scherer Plant units in which case the expense is based on units of production during the first six (6) months of operation and the remaining life on straight line depreciation. The depreciation expense for generating units is adjusted to reflect the AFUDC determined in Section C2.2.2. The depreciation expense associated with the generator step-up substation facilities is determined on the basis of the gross investment in generator step-up substation facilities and the associated depreciation rates. The depreciation expense associated with general plant is ailocated to the specific coal-fired electric generating unit and its step-up substation in the same manner as the general plant allocations described in Section C2.2.5.

Section C2.2.12: Amortization of Investment Tax Credits ("AITC") is computed for each coal-fired electric generating unit. AITC associated with the transmission plant is allocated to the generator step-up substation facilities on the basis of the ratio of the depreciation expense of the generator step-up substation facilities to the depreciation expense of the transmission plant. The AITC associated with general plant is allocated to the specific coal-fired electric generating unit and its step-up substation in the same manner as the general plant allocations described in Section C2.2.5.

Section C2.2.13: Real and Personal Property Taxes are computed for the specific coal-fired electric generating unit and its associated step-up substation in a manner which equitably relates the pro rata share of such taxes to each facility with regard to its value for tax purposes and which is consistent with computation of such taxes for the respective operating company. The real and personal property taxes associated with general plant are allocated in accordance with the general plant allocation described in Section C2.2.5. Detailed documentation of computation of the real and personal property taxes for each unit in accordance with the computation of such taxes for the operating company will be prepared, and if requested, will be made available.

Section C2.2.14: Payroll Taxes applicable to a specific coal-fired electric generating unit and its step-up substation are computed in the following manner. The expected payroll tax rates are applied to the budgeted salaries and wages developed in Section C2.2.17. The payroll taxes reflect the use of the taxable wage base and the maximum payroll tax payable during each month of the Contract Year.

Section C2.2.15: Total Production Fixed Expenses represent the direct and allocated fixed expenses associated with the coal-fired electric generating unit and generator step-up facilities and are the summation of Section C2.2.9 (Fixed Operation and Maintenance Expense) through Section C2.2.14 (Payroll Taxes) and is the value for "E" for capacity in the formula in Section C2.2 for each applicable coal-fired electric generating unit.

Section C2.2.16: The Cost of Capital and Associated Income Taxes are computed in the following manner:

$$CM = [(DR \times i) + (PR \times p) + (ER \times c)]$$

Where: $DR + PR + ER = 1.0$

$$IT = \frac{T}{1 - T} \times [(PR \times p) + (ER \times c)]$$

Where: $T = \dfrac{F + S - 2FS}{1 - FS}$ (federal income taxes deductible for state income tax purposes)

or

$T = F + S - FS$ (federal income taxes not deductible for state income tax purposes)

CM = Weighted average cost of capital associated with the operating company's cost of construction of the unit (%).

IT = Income tax requirement associated with the preferred stock and common equity weighted cost of capital associated with the operating company's cost of construction of the unit (%).

T = Combined state and federal income tax rate.

F = Federal income tax rate.

S = State income tax rate.

DR = Ratio of debt capital[2].

PR = Ratio of preferred stock[2].

ER = Ratio of common equity[2].

C = Return on common equity of Southern Companies as determined in Article VI of this Unit Power Sale Manual.

2. The components of the capital structure of the operating company will be determined from the most recent Quarterly Report on Form 10-Q (or in event such report ceases to be required to be filed by an operating company, such other report to a governmental agency containing the operating company's capital structure) at the time the unit goes into commercial operation; except the capital structure for Miller Plant Unit 1 which will be determined by calculating the simple arithmetical averages of each of the components as determined by the capitalization as recorded on Form 10-K (or U5S where 10-K is not applicable) for end of year capitalization for each year 1972 through 1978. In the case of a unit which will go into commercial operation during the Contract Year, the components of the capital structure may change between the information available at the time the estimated capacity charges are developed and the time the applicable Form 10-Q is available. This one time change in capital structure will be recognized as soon as practicable.

i = The cost of debt capital[3], which shall be determined as of the date the unit goes into commercial operation, shall be the weighted average percent rate of first mortgage bonds issued during the construction of the unit, which shall be calculated by applying the annual percent interest rate of the most recent issue of first mortgage bonds prior to the incurrence of each monthly capital expenditure on the unit. The cost of debt capital shall be modified after the date of commercial operation to account for additional monthly capital expenditures to the unit by applying the annual percent interest rate of the most recent issue of first mortgage bonds prior to the incurrence of such monthly capital expenditure. Such costs of debt capital shall be modified to include the amount and the cost of pollution control bonds specifically related to the unit.

3. In the case of Miller Plant Unit 1 only, the cost of debt capital will be adjusted to account for the period during construction of the unit exceeding twelve months when no first mortgage bonds were issued. Adjustment for such periods will be as follows: The monthly capital expenditures occurring after the twelve-month period will have applied to them the annual percentage rate of first mortgage bonds issued up to six months subsequent to such expenditures. If no such bond issue were made in the six-month period subsequent to the monthly capital expenditure, the rate of the most recent previous bond issue will continue to be applied to such expenditures incurred up to six months prior to the next bond issue.

p = The cost cf preferred stock[4], which shall be determined as of the date the unit goes into commercial operation, shall be the weighted average dividend percentage rate of such stock, which such percent rate shall be calculated by applying the annual dividend percentage rate of the most recent issue of preferred stock prior to the incurrence of each monthly capital expenditure on the unit.

The cost of preferred stock shall be modified after the date of commercial operation to account for additional monthly capital expenditures to the unit by applying the annual percentage interest rate of the most recent issue of preferred stock prior to the incurrence of such monthly capital expenditure.

Section c2.2.17: Salaries and Wages are budgeted and accounted for on an actual basis by each operating company for each functional group and the specific coal-fired electric generating unit for the Contract Year. The budgeted salaries and wages account for changes in wage rates and number of employees.

The salaries and wages associated with the administrative and general classification are allocated to the functions including the specific coal-fired electric generating unit based upon the ratio of the functional group's salaries and wages to the total salaries and wages less the administrative and general classification's salaries and wages. The salaries and wages associated with the transmission function, including the allocated administrative and general salaries and wages, are allocated to the transmission plant's substations based upon the labor in FERC Accounts 562, 569, and 570 and are further allocated to the unit's generator step-up substation facilities on the basis of the ratio of the gross investment in the specific

4. In the case of Miller Plant Unit 1 only, the cost of preferred stock will be adjusted to account for the period during construction of the unit exceeding twelve months when no issues of preferred stock were issued. Adjustments for such periods will be made as follows: The monthly capital expenditures occurring after the twelve-month period will have applied to them the annual dividend percentage rate of preferred stock issued up to six months subsequent to such expenditures. If no such stock issue were made in the six months subsequent to the monthly capital expenditure, the rate of the most recent previous preferred stock issue will continue to be applied to such expenditures incurred up to six months prior to the next preferred stock issue.

unit's step-up substation to the gross investment in the transmission substations unless a direct assignment of salaries and wages is available from the operating company's records.

The salaries and wages for a specific unit which is jointly owned are computed for one hundred percent (100%) of the unit. The total salaries and wages for such jointly owned units are allocated on the basis of percent ownership.

For a unit which does not have a historical basis of salaries and wages, the most recent vintage and similar coal-fired unit that does have a historical basis will be used for the first year's estimate.

Section C2.2.18: Adjustment for Delayed Unit Subject to Sections 2.4.3 or 2.4.4 of the UPS Agreement: The development of the capacity charge for a unit delayed subject to the provisions of Section 2.4.3 or Section 2.4.4 of the UPS Agreement will be made in accordance with the above described methodology subject to the following:

The increased amount of AFUDC attributable to the delay of the unit will not be included in the gross investment of the unit except as this increased amount of AFUDC is offset by savings made available through the substitution of less expensive capacity during the period of the delay. The amount of savings as may be available will be determined from the difference between the estimated cost of the unit as if it had not been delayed and the actual cost of the substituted unit.

Section C2.2.19: Adjustment to Cost of Capital Resultins From Retirement or Redemption of Outstandins Securities: The cost of capital calculation provided in Section C2.2.16 is impacted when security issues are retired or redeemed in any of the following ways: (i) a security issue is completely redeemed at one time; (ii) the outstanding balance of a security issue is redeemed in its entirety; (iii) a security issue is partially redeemed in the amount of $10 million, or more; or (iv) a security issue is partially redeemed in an amount less than $10 million, but the cumulative total redemption of the security redeemed meets or exceeds a $10 million increment.

Adjustments to the cost of capital calculations resulting from retirements or redemptions (including subsequent generation refundings) shall be as follows:

1) Determine the existence of a refundinq security. The refunding security will be the last like security issued by the applicable Operating Company within the three-month period immediately preceding the retirement or redemption. A "like security" shall include: (a) taxable-debt for taxable-debt; (b) tax-exempt debt for tax-exempt debt; or (c) preferred stock for preferred stock. Other characteristics will not distinguish securities for purposes of identifying like securities.

   If no like securities have been issued during the three-month period immediately preceding the triggering retirement or redemption, the first like security issued within the three-month period immediately after the retirement or redemption will be identified as the refunding security.

   a) If the security being retired or redeemed is a long-term taxable security (that is, with a maturity of 30 years or more) and no taxable debt securities have been issued within three months prior or subsequent to a triggering retirement or redemption, the last like security issued (regardless of issuance date) will be used; provided, however, that its coupon rate falls within an acceptable range of security yields.

      The range of acceptable security yields will be determined by selecting from Part II - Table 4 of the Salomon Brothers publication entitled Analytical Record of Yields and Yield Spreads (or a similar publication acceptable to both parties), the new utilities issue long-term yields under the applicable debt rating for the period beginning three months prior to the triggering retirement or redemption through three months after the retirement or redemption (i.e., a total of seven monthly readings). If the current long-term taxable debt rating for the applicable Operating Company is not shown, the appropriate rates will be obtained in writing from a nationally recognized investment bank reasonably acceptable to both JEA and the applicable Operating Company, and one who regularly participates in the sale of securities of investor-owned utilities. The low end of the acceptable yield range will be the lowest yield during the seven months and the high end of the range will be the highest yield during the seven months. If no like security was issued within the seven month range and the last like security issued falls outside the range established hereby, the range will be adjusted pursuant to paragraph (e) below. The low and high end of the acceptable yield range may be adjusted a maximum of 10 basis points.

b) If the security being retired or redeemed is a taxable security with an original maturity of less than 30 years (i.e., a "non-long term taxable debt security") and no taxable debt securities have been issued within three months before or after a triggering retirement or redemption, the last like security issued (regardless of issuance date) will be acceptable; provided, however, that its coupon rate falls within an acceptable range of security yields. The range of acceptable security yields will be determined by identifying the non-long term taxable debt securities issued by electric utilities (having the same debt rating as the applicable Operating Company as of the triggering event) for three months immediately before and three months after a triggering retirement or redemption. The rates will be obtained, in writing, from a nationally recognized investment bank reasonably acceptable to JEA and the applicable Operating Company, and one who regularly participates in the sale of securities of investor-owned utilities. The low end of the acceptable yield range will be the lowest yield during the seven months and the high end of the range will be the highest yield during the seven months. If no like security was issued within the seven month range and the last like security issued falls outside the range established hereby, the range will be adjusted pursuant to paragraph (e) below.

c) If the security being retired or redeemed is a long-term tax-exempt security (i.e., maturity of 30 years or more) and no tax-exempt debt securities have been issued within three months before or after a triggering retirement or redemption, the last like security issued (regardless of issuance date) will be acceptable; provided, however, that its coupon rate falls within a range of acceptable security yields. The range of acceptable security yields will be determined by selecting from Part III - Table 7 of the Salomon Brothers publication entitled Analytical Record of Yields and Yield Spreads, under the column entitled "New Issue A-rated Elec. Rev. 30 Years," (or a similar publication acceptable to both parties), for three months immediately before and three months after the retirement or redemption. If the current tax-exempt debt rating €or the applicable Operating Company is not shown, the range of acceptable security yields will be determined by identifying the long-term tax-exempt debt securities issued by electric utilities (having the same debt rating as the applicable Operating Company as of the triggering event) for three months before and three months after the retirement or redemption. The rates will be obtained in writing from a nationally recognized investment bank reasonably acceptable to JEA and the applicable Operating Company and one who regularly participates in the sale of securities of investor-owned utilities. The low end of the range will be the lowest yield during the seven months and the high end of the range will be the highest yield during the seven months. If no like security was issued within the seven month range and the last like security issued falls outside the range established hereby, the range will be adjusted pursuant to paragraph (e) below.

d) If no like preferred stock securities have been issued within three months prior or three months subsequent to a triggering retirement or redemption, the last like security issued will be acceptable; provided, however, that its dividend rate falls within an acceptable range of security yields. The range of acceptable yields will be determined by selecting from Part V - Table 3 of the Salomon Brothers publication entitled Analytical Record of Yields and Yield Spreads (or a similar publication mutually acceptable to JEA and the applicable Operating Company), for the three months immediately before and three months after the month of the triggering retirement or redemption. If the current preferred stock rating for the applicable Operating Company is not shown, the appropriate rates will be obtained in writing from a nationally recognized investment bank reasonably acceptable to both JEA and the applicable Operating Company, and one who regularly participates in the sale of securities of investor-owned utilities. The low end of the range will be the lowest yield during the seven months and the high end of the range will be the highest yield during the seven months. If no like security was issued within the seven month range and the last like security issued falls outside the range established hereby, the range will be adjusted pursuant to paragraph (e) below.

e) If no like long-term taxable debt security, non-long-term taxable debt security, long-term tax-exempt security, or preferred stock issues, as the case may be, have occurred within three months immediately before or three months after a triggering retirement or redemption, and the last like security issue falls outside of the range established by these guidelines, the low and high end of the acceptable yield range may be adjusted in increments of 10 basis points and the last like security that falls within the range will be used, regardless of the issuance date. A previously identified refunding issue (debt and preferred stock, respectively) may be identified as the refunding issue for a subsequent retirement or redemption. Following triggering partial retirements or redemptions, the replacement rate used for the principal amount that triggers the adjustment will also be used for the partial retirements and/or redemptions which have occurred but did not meet the $10 million increment.

f) The applicable Operating Company will notify JEA, in writing, of any adjustments made to the cost of capital pursuant to this Section C2.2.19 and will include with such notice all appropriate supporting documentation. Such notice and documentation shall be provided in conjunction with the first invoice which reflects such adjustment.

2) Treatment of premium. Whenever a security is retired or redeemed and the affected Operating Company purchases all or part of the security from the holder at a premium, the unamortized discount and expense and the premium expense of a redeemed issue will be included in the cost of capital calculation for the replacement issue for unit power sales capital costs. The calculation will use the following methodology:

a) The net proceeds of the replacement issue will be reduced by the amount of the unamortized debt discount and expense of the redeemed issue, the call expense, and the premium expense. The expenses, discounts, call premiums and net proceeds will be prorated as appropriate to reflect differences in the amounts of the refunding and the refunded issues and in the calculation of the replacement rates; and

b) The yield to maturity of the replacement issue will be calculated using the adjusted net proceeds.

The costs of debt and preferred stock shall reflect actual cost experienced by each Operating Company. To the extent unanticipated financial circumstances arise in the future, exceptions to the methodology for treatment of a premium will be evaluated jointly by the parties hereto on a case-by-case basis.

3) Treatment of Multiple Security Sales. When more than one security sale occurs on the same day, the cost to the applicable Operating Company with regard to each security issue will be calculated based on the net proceeds from the issue. A weighted average rate, based on the principal amount issued and the cost to the applicable Operating Company of each individual issue, will be determined. The individual securities bearing the rate closest to the weighted average rate will be used for purposes of this Manual.

# ARTICLE III

## DERIVATION OF CAPACITY CHARGE FOR TRANSMISSION FACILITIES

This article of this Unit Power Sale Manual establishes the formulary methodology for deriving the capacity charge for transmission facilities for unit power sales under the UPS Agreement.

Section C3.1 Transmission Capacitv Charae: The computation of the transmission capacity cnarge for transmission facilities is based on the investment, expenses, and load related to transmission lines rated 115 kV and above and associated substations. This capacity charge excludes the investment and expenses associated with the generator step-up substations and the investment, expenses, and associated load in transmission owned by Oglethorpe Power Corporation ("OPC"), Municipal Electric Authority of Georgia ("MEAG"), and City of Dalton, Georgia ("Dalton"). The transmission capacity charge for unit power sales under the UPS Agreement from APC's Miller Plant Units 1, 2, 3, and 4 to Corporation will be the sum of APC's transmission capacity charge ($/kW-month) and GaPC's transmission capacity charge ($/kW-month). The transmission capacity charge for unit power sales under the UPS Agreement from GaPC's and GuPC's ownership in Scherer Plant Unit 3 to Corporation will be the GaPC transmission capacity charge ($/kW-month).

The computation of the transmission capacity charge is made for each period of the contract Year. For purposes of this Article of this Unit Power Sale Manual, the Contract Year is divided into two distinct periods, January through May, and June through December. This division of the Contract Year into two periods is necessary in order to recognize that Southern Companies consider an operating year to be June 1 thr'ough May 31 of the following year.

The transmission charges for each period of the Contract Year will be shown on the Unit Power Sale Informational Schedule and will be revised in accordance with the UPS Agreement in subsequent calendar years.

Section C3.2 Derivation of Transmission Capacity Charge of APC and GaPC: The derivation of the transmission capacity charge of APC and GaPC is based on the investments, expenses, and load related to transmission lines and associated substation facilities rated 115 kV and above (excluding generator step-up substations) of each such company during the Contract Year and the cost of capital and associated income taxes in each period of the Contract Year. This derivation excludes the investment, expenses, and

After net general plant has been allocated to transmission plant, it is allocated to the 115 kV and above facilities based on the ratio of the total net investment in the 115 kV and above facilities to the total net transmission plant investment.

Section C3.2.6: Working Capital is the summation of cash working capital, prepayments, deposits (if any), and materials and supplies, and is computed for each month of the Contract Year. The cash working capital for the transmission facilities rated 115 kV and above is calculated by taking one-eighth (45/360) of the sum of the annualized fixed O&M and A&G expenses. The fixed O&M and A&G expenses are developed in Sections C3.2.9 and C3.2.10, respectively.

Prepayments are computed on the basis of a thirteen (13) month average and are directly assigned to production, transmission, general plant functions, and the specific coal-fired generating unit. Prepayments associated with general plant are allocated to the transmission function on the basis of salaries and wages as described in Section C3.2.17. The amount allocated and assigned to the transmission function is allocated to the facilities rated 115 kV and above on the basis of O&M expenses as described in Section C3.2.9.

Materials and supplies are computed on the basis of a thirteen (13) month average and consist of plant materials and operating supplies recorded in FERC Account 154 that are related to the transmission function. The plant materials and operating supplies, FERC Account 154, are allocated to the transmission facilities rated 115 kV and above on the basis of the ratio of the gross investment excluding land of the facilities rated 115 kV and above to the gross investment excluding land in the transmission plant.

Deposits are included as a working capital requirement to reflect the operating agreements that exist between one operating company and another operating company for the operation of transmission facilities. It should be noted that while these deposits increase the working capital requirements of one operating company, they have a corresponding reduction in the working capital requirements of another operating company.

Section C3.2.7 Accumulated Deferred Income Taxes are the net total of FERC Accounts 190, 281, 292, and 283 which have been analyzed and allocated by APC and GaPC in accordance with each FERC Account's functional use, including amounts previously recorded in such accounts and reclassified as a result of the adoption of SFAS No. 109, and excluding amounts recorded in such accounts as a result of the adoption of SFAS No. 109, such that the required adoption of SFAS No. 109 will have no impact on the amount of the capacity charge. The portion related to general plant is allocated to the transmission function as described in Section C3.2.5. The allocation to facilities rated 115 kV and above is on the basis of net plant less land.

Section C3.2.8: Total Net Transmission Investment represents the direct ana allocated investments that are associated with the facilities rated 115 kV ana above ana is the summation of Section C3.2.4 (Net Transmission Investment) through C3.2.7 (Accumulated Deferred Income Taxes) and is the value for "I" in the formulae in Section C3.2.

Section C3.2.9: Transmission Operation and Maintenance Expenses, FERC Accounts 560 through 573 are allocated in relation *to* the net transmission plant associated with the facilities considered herein unless more detailed assignments can be made from existing operating company records. The O&M expenses will be adjusted to reflect actual O&M expenses pursuant to Article IX of this Unit power sale Manual.

Section C3.2.10: Administrative and General Expenses, FERC Accounts 920 through 935, excluding FERC Account 924, are allocated to the transmission function based on salaries and wages and to facilities rated 115 kV and above on the basis of net investment. FERC Account *924* is directly assigned to function APC and GaPC and allocated within function based on net investment.

Section C3.2.11: Depreciation Expense and Amortization of Investment Tax Credit (AITC) are developed as follows. The depreciation expense for transmission plant is taken directly from the records of APC and GaPC. The depreciation expense associated with the 115 kV and above facilities is determined on the basis of the gross investment in 115 kV and above facilities and the associated depreciation rates. The depreciation expense and related AITC associated with general plant are allocated to transmission plant in accordance with the general plant allocations as described in Section C3.2.5. The general plant depreciation expense allocated to transmission function is further allocated to the 115 kV and above facilities on the basis of depreciation expense related to the 115 kV and above facilities and the total transmission plant.

The AITC associated with the transmission plant is allocated to the transmission facilities rated 115 kV and above on the basis of the ratio of the depreciation expense of the transmission facilities rated 115 kV and above to the depreciation expense of the transmission plant. .

Section C3.2.12: Real and Personal Property Taxes are assigned directly to the transmission plant. These taxes are allocated to the 115 kV and above facilities based on the ratio of the net investment in the 115 kV and above facilities to the net transmission plant. The real and personal property taxes associated with general plant are allocated to the transmission function on the basis of salaries and wages as described in Section C3.2.17 and within transmission to the facilities rated 115 kV and above on the basis of net investment.

Section C3.2.13: Payroll Taxes applicable to the 115 kV and above transmission facilities are computed in the following manner. The expected payroll tax rates are applied to the budgeted salaries and wages developed in Section C3.2.17 to obtain each function's payroll taxes. The payroll taxes reflect the use of the taxable wage base ana the maximum payroll tax payable during each month of the Contract Year.

Section C3.2.14: Credits (or Debits) to Operating Expenses: The revenues classified as "Other Operating Revenue" in APC's and GaPC's budget will be credited to the operatinq expenses if the transmission facilities considered herein were responsible for such revenues (e.g., such revenues associated with Long Term Power sales, Short Term Power sales, and unit power sales). If the revenues for transmission service are not credited, the estimated demands associated with the revenues will be added to the demand of the affected operating company for the transmission rate calculation. Because an operating company may have operating agreements with third parties with respect to the transmission facilities considered herein, there may be revenues or expenses associated with the facilities rated 115 kV and above that will be appropriately credited or debited to the operating expenses for the affected operating company. In addition, revenues associated with the transmission facilities rated 115 kV and above that appear in the "Purchased Power Account" in APC's and GaPC's budget (e.g., such revenues from Long Term Power sales, Short Term Power sales, and unit power sales) will be credited to the operating expenses for these transmission facilities.

Section C3.2.15: Total Transmission Expenses represent the direct and allocated fixed expenses associated with the facilities considered herein and are the summation of Section C3.2.9 (Transmission Operation and Maintenance Expenses) through Section C3.2.14 (Credits (or Debits) to Operating Expenses) and is the value for "E" in the formulae in Section C3.2.

Section C3.2.16: The Cost of Capital and Associated Income Taxes are computed in the following manner:

$$CM = ((DR \times i) + (PR \times p) + (ER \times c))$$

Where: $DR + PR + ER = 1.0$

$$IT = \frac{T}{1 - T} \times ((PR \times p) + (ER \times c))$$

Where: $T = \frac{F + S - 2FS}{1 - FS}$ (federal income taxes deductible for state income tax purposes)

or

$T = F + S - FS$ (federal income taxes not deductible for state income tax purposes)

CM = Weighted average cost of capital (%).

IT = Income tax requirement associated with preferred stock and common equity weighted cost of capital (%).

DR = Ratio of debt capital (target ratio; includes first mortgage bonds' pollution control obligations, and capitalized leases).

PR = Ratio of preferred stock (target ratio).

ER = Ratio of common equity (target ratio).

i = Embedded cost of debt capital (%).

p = Embedded cost of preferred stock (%).

c = Return on common equity as specified in Article VI of this Unit Power Sale Manual.

T = combined state and federal income tax rate.

F = Federal income tax rate.

S = State income tax rate.

Section C3.2.17: Salaries and Wages are budgeted and accounted for on an actual basis by APC and GaPC for each functional group. The budgeted salaries and wages account for changes in wage rates and number of employees.

The salaries and wages associated with the administrative and general classification are allocated to the functional groups based upon the ratio of the functional group's salaries and wages to the total salaries and wages less the administrative and general classification's salaries and wages.

The transmission plant salaries and wages which include the allocated A&G, are allocated to the 115 kV and **above** facilities based on the ratio of the net investment in the 115 kV and above facilities to the total net transmission plant investment.

ARTICLE IV

DERIVATION OF FUEL COSTS
AND NORMALIZED FUEL COSTS
FOR ELECTRIC GENERATING UNITS

This article of this Unit Power Sale Manual establishes the definition and provides the procedures for determining the Fuel Costs and Normalized Fuel Costs for the computation of charges for unit power sales under the UPS Agreement.

Section C4.0 Fuel Costs: The Fuel Cost ($/mWh) for a unit is defined as the cost ($) of the fuel issued from the weighted-average stockpile for the unit divided by the net electrical output (mWhs) of the unit during operation periods of the unit during the month energy was delivered under the UPS Agreement. Operation periods as used herein include all hours in which the net electrical output'of the unit is greater than zero. The cost of fuel issued for the unit will be the actual monthly cost of fossil fuel issued from FERC Account 151, including the actual monthly cost of qaseous fuels charged directly to FERC Account 501. In the event that there were no operation periods of a unit during a month, the Fuel Cost for the unit for such month will be equal to the Fuel Cost for the unit in the first preceding month in which there were operation periods.

Section C4.1: Normalized Fuel Costs: The Normalized Fuel Cost ($/mWh) for a unit is defined as the average net heat rate (millions of BTU's per mWh) of such unit at a specified generation level multiplied by the actual monthly cost ($) of fossil fuel issued from FERC Account 151, including the actual monthly cost of qaseous fuels charged directly to FERC Account 501, and divided by the heat content (millions of BTU's) of such fuel issued for the month. In the event the cost of fuel issued is zero for a unit during a month, the cost of fuel issued and the associated heat content for other similar unit(s) receiving fuel from the same stockpile in that month will be used in the calculation of the Normalized Fuel Cost. Furthermore, in the event there was no fuel issued from such stockpile in that month, the cost of fuel issued and the associated heat content for the first preceding month in which there was fuel issued will be used in the calculation of the Normalized Fuel Cost. The specified generation level at which the average net heat rate is determined shall be sixty-five percent (65%) of the Net Dependable Capacity of each unit, unless otherwise mutually agreed by the parties hereto. This generation level will be reviewed periodically by the Unit Power Sales Operating Committee to determine if it shall be revised to more accurately represent the normal historical or projected output factor for each unit. The average net heat rate, as used herein, shall be calculated for each unit from the net heat rate equation which is used in the economic dispatch for Southern Companies.

Issued by: William L. Marshall, Jr., Vice President
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# ARTICLE V

## DERIVATION OF FIXED OPERATION AND MAINTENANCE, VARIABLE OPERATION AND MAINTENANCE, AND IN-PLANT FUEL HANDLING EXPENSES FOR ELECTRIC GENERATING UNITS

This article of this Unit Power Sale Manual establishes the formulary method €or deriving fixed operation and maintenance, variable operation and maintenance, and in-plant fuel handling expenses for the computation of charges for services under the Agreement.

Section C5.1 Variable Operation and Maintenance Expenses: The variable operation and maintenance expenses ($/Mwh) for a unit shall be based upon the following components budgeted for the unit for the Contract Year: (i) all contract labor, (ii) all operating material charged to Accounts 502 and 505, and (iii) all maintenance material charged to Accounts 512 and 513. The variable operation and maintenance expenses for the unit shall be the sum of the components listed above ($) divided by the budgeted net electric output of the unit (in MWhs) for the Contract Year.

Section C5.2 In-Plant Fuel Handling Expenses: The in-plant fuel handling expenses ($/MWh) for a unit shall be the in-plant fuel handling costs (dollars) budgeted in FERC Account 501 divided by the budgeted net electric output (MWhs) for the unit during the Contract Year. The in-plant fuel handling expenses shall include all expenses in Account 501 except the cost of fuel which includes freight, switching, demurrage and other transportation charges.

Section C5.3 Data to be Provided: The date used in the determination of the fixed and variable operation and maintenance expenses and the in-plant fuel handling expenses for each unit each Contract Year, will be provided to the purchasers of unit power in accordance with Article VIII.

ARTICLE **VI**

DERIVATION OF
RETURN ON COMMON EQUITY

This article of this Unit Power Sale Manual establishes the return on common equity used in the computation of capacity charges for unit power sales under the UPS Agreement.

Section ***C6.0*** Return on Common Equity: For the purposes of determining charges for unit power and transmission, as set forth in this Unit Power Sale Manual and the UPS Agreement, the return on common equity (c) for Southern Companies **shall** be eleven percent **(11.00%)**. This return on common equity will be reviewed periodically to determine if revisions are required. Any such revisions shall be made in accordance with the provisions ***of*** Section **5.3** and Section 5.5 of the UPS Agreement.

ARTICLE VII

DERIVATION OF
AVERAGE TRANSMISSION LOSS PERCENTAGES

This article of this Unit Power Sale Manual establishes the average transmission loss percentages used in the computation of capacity and energy charges under the UPS Agreement.

Section C7.0 Average Transmission Loss Percentages: For the purposes of determining charges for capacity and energy, as set forth in this Unit Power Sale Manual and the UPS Agreement, the average transmission loss percentage of southern Companies associated with capacity (%L) and the average transmission loss percentage of Southers Companies associated with energy ($\%L_e$) shall each be three percent (3%). These average loss percentages will be reviewed periodically from annual power supply statistical reports and from load-flow studies to determine if any revisions are required. Any such revisions shall be made in accordance with the provisions of Section 5.3 of the UPS Agreement.

## ARTICLE VIII

## UNIT POWER SALE
## INFORMATIONAL SCHEDULE AND SUPPORT SCHEDULES
## AND MONTHLY REPORT OF ENERGY TRANSACTIONS

Section C8.0 Support Schedules: The development of cost components for the sale of unit power will be provided on formats mutually agreed to by the parties hereto. Such support schedules will describe the source of the data with reference to the applicable articles and sections of this Unit Power Sale Manual and will show how the data is used in the computation of cost components shown on the Unit Power Sale Informational Schedule.

Section C8.1 Unit Power Sale Informational Schedule: The results of the formulary methodology set forth in this Unit Power Sale Manual shall be displayed on a Unit Power Sale Informational schedule for the Contract Year in a format mutually agreed to by the parties hereto.

Section C8.2 Schedules for Estimated and Actual Charges: The support schedules described in Section C8.0 shall be recomputed to include actual cost data as contemplated in Article IX of this Unit Power Sale Manual and supplied to unit power sales purchasers.

Section C8.3 Monthlv Report of Energy Transactions: Monthly reports shall be supplied to unit power sales purchasers, which reports will list the hourly energy transactions and the energy rates which are applicable to each hourly transaction. The energy rates used in the calculation of the energy charge for each unit during each hour will also be identified. Both preliminary and actual cost data will be supplied as provided for in Section 7.2 of the UPS Agreement.

ARTICLE IX

ADJUSTMENT FOR ACTUAL COST

This article of this Unit Power Sale Manual establishes the formulary components of the unit power capacity charge and the transmission capacity charge which are subject to adjustment for actual cost. Such adjustments for actual cost pursuant to Section 6.2 of the UPS Agreement will be made using the applicable procedures described in Article II, Article III, and Article V of this Unit Power Sale Manual.

Section C9.0 Capacity Cost for Unit Power: The monthly capacity charges computed under Article II of this Unit Power Sale Manual fo each unit participating in sales of unit power €or the Contract Year will be recalculated using the formula specified in Section C2.2 and the actual cost data for the unit. All cost items contained in Article II of this Unit Power Sale Manual will be adjusted to reflect their actual costs. The adjustment will be made as soon as practicable following the end of the month, but shall be made within three (3) months of the monthly rendered bill. The capital structure and cost of debt capital and preferred stock will be modified as described in Section C2.2.16 and further as provided for in Section C2.2.19.

Section C9.1 Capacity Cost for Transmission Service: The transmission capacity cost computed under Article III of this Unit Power Sale Manual for the Contract Year will be recalculated using actual cost and load data and the formulae specified in Section C3.2. Southern Companies shall make this adjustment on a periodic basis, but not less frequently than annually as soon as practicable following the end of the Contract Year.

Section C9.2 Variable Operation and Maintenance Expenses: The variable operation and maintenance expenses and the in-plant fuel handling expenses, as defined and computed in accordance with Article V, will be recalculated using actual data. The adjustment for variable operation and maintenance expenses and the in-plant fuel handling expenses will be handled separately from the energy billing. This adjustment will be made annually (or for such lesser periods as mutually agreed by the parties hereto) using the actual data for expenses and net electrical output of each unit. Such annual adjustment will be made for the Contract Year as soon as practicable following the end of the Contract Year.

Section C9.3 Administrative Cost for Adjustment Procedure: FPL as a purchaser of unit power shall reimburse Southern Companies €or its equal share of all costs incurred by Southern Companies directly in administering this Article IX of this Unit Power Sale Manual. Such costs shall be accumulated by Southern Companies at standard rates of each operating company and SCS for the services performed and shall include, but not be limited to, charges for computer time associated with the calculation of capacity charges based on actual data, personnel engaged in administering this Article IX of this Unit Power Sale Manual based on time actually spent, and materials and supplies consumed in connection with administration of this Article IX of this Unit Power Sale Manual. Such administrative charges will not be included in the development of capacity charges in Section C2.2.10.

# ATTACHMENTS

Southern Company Services, Inc.
800 Shades Creek Parkway
Post Office Box 2625
Birmingham, Alabama 35202
Telephone 205 870-6287

R. O. Usry
Vice President

the southern electric system

April 25, 1990

Mr. M. H. Phillips
Executive Vice President
Florida Power Corporation
3201 34th Street, South
St. Petersburg, Florida 33711

Re: Adoption of Marginal Replacement Fuel Cost in the Unit Power Sales Agreement between Florida Power Corporation and Southern Companies

Dear Mr. Phillips:

As previously discussed with representatives of Florida Pover Corporation ("Corporation"), Alabama Power Company, Georgia Fower Company, Gulf Pover Company, Mississippi Power Company, Savannah Electric and Pover Conpany and Southern Company Services, Inc. (hereinafter "Southern electric system" or "Southern Companies") propose to adopt a new fuel cost methodology for use in dispatching generating units on the Southern electric systen. Under the proposed procedure, units will be dispatched based on the "marginal replacement fuel cost." The guidelines for determining the narginal replacenent fuel cost for use in dispatch are attached hereto as Attachment 1. This letter agreement is intended to explain and clarify the proposed practice and its effects on the Unit Power Sales ("UPS") Agreement between Southern Companies and Corporation dated July 19, 1988.

Currently, the Southern electric systen utilizes "blended replacement fuel cost" to determine the order of dispatch of the generating units on the system and to price off-system energy transactions. Blended replacement fuel cost is defined as the weighted average cost of fuel receipts for the previous month (bcth long-ten contract and spot-market receipts) and the projected fuel receipts for the current month. For incrementally priced off-systea energy transactions (such as Alternate, Supplemental, Discretionary, Replacement and the Long-Term Power Option), specific increments of unit generation are identified as sources

nr. M. H. Phillips
April 25, 1990
Page 2

of supply, and the fuel component is priced using the blended replacenent fuel cost of each increment of unit generation.

Because spot-market fuel prices are presently lower than long-term prices, units with fewer long-term fuel supply commitments have a distinct advantage in dispatch over units with higher levels of long-term contract fuel supplies. Units with small quantities of long-term fuel supplies can obtain substantial amounts of spot-market fuel thereby resulting in a lover blended fuel cost which, in turn, causes the units to be dispatched first and consune more fuel. The increased loading of these units allows procurement of.. additional spot-market fuel that further reduces their blended replacement fuel cost and starts a spiral effect of decreasing cost and increasing generation. On the Southern electric system, these units with fewer long-ten commitments are generally the older, less efficient units that should primarily provide reserve generation.

In contrast, units with higher levels of long-tern contracts and, hence, higher costs have decreased opportunities to generate ana to improve their order in dispatch by procuring more spot-market fuel. Generally, these units are the never, more efficient units that should supply more base load energy. Based on studies, Southern companies believe that the continued use of blended replacenent fuel COST. say not result in the most efficient operating and pricing signals being provided for future fuel procurement decisions or the desired burns at the most efficient plants.

To resolve any problens associated with dispatching units based on blended replacement fuel cost, the Southern electric system proposes to utilize marginal . replacenent fuel cost to dispatch system generating units, Although units will be dis-patched based on marginal replacement fuel cost, off-system energy transactions will continue to be priced based on blended replace-ment fuel cost. This is necessary because marginal replacement fuel cost at sone plants represents only a small percentage of the total cost of the fuel consumed. Therefore, a different methodolo-gy must be used in the pricing process to recover all fuel expenses incurred in operating the unit. The use of blended replacement fuel cost for pricing is a proven and reliable methodology for ensuring that all fuel costs are recovered and, therefore, that methodology will be retained in pricing off-system energy transac-tions.

Using the proposed procedure, specific unit increnents for the aggregate of off-system energy transactions will be identified by a dispatch simulation using marginal replaceaent fuel cost. Once identified, the specific unit increments will be assigned their blended replacement fuel cost and reordered in ascending order of cost for pricing each off-system energy transaction. The change to this proposed nethod of dispatch and fuel pricing should result in decreased production cost, thereby providing savings to all customers, It should also provide appropriate fuel procurement signals to minimize the cost of fuel purchases under changing market conditions.

Because the proposed fuel pricing methodology results in the use of a different fuel cost for dispatch and pricing off-system energy transactions, energy rates that include the incremental generating cost of the Southern electric system as a component of the pricing methodology could be affected. These energy rates include the following: Alternate, Supplemental, Discretionary and Replacement Energy under the UPS Agreement and the Long Term Pover option provided under Exhibit B of the UPS Agreenent. The proposed procedure will not change the methodology used in determining UPS Base and Normalized Energy Rates.

Over time, as units are dispatched differently, the fuel cost and variable operation and maintenance ("O&M") expense at each unit may change. The Southern electric system will not revise the O&M expense shown in the 1990 Informational Filings, but future informational filings will reflect any such changes. The proposed methodology may also have an effect on the fuel stock coaponent of working capital which, in turn, affects the calculation of capacity charge rates. As more spot-market fuel is procured and the fuel stock changes, the contract capacity charge rates will reflect this change. The adoption of marginal replacement fuel cost for dispatch cay also result in a chanqe in unit operations, including the operaticn of certain units at minimum output levels.

The adoption of the new nethod of dispatch Will necessitate the amendment of a nucber of rates that Southern Companies have filed with the Federal Energy Regulatory Commission ("FERC"). Because recalculating dispatch would be extremely inpractical, if not impossible, the narginal replacement fuel cost procedure will not be implemented until it is accepted for use under The Southern Conpany Systen Intercoapany Interchange Contract and all other wholesale and retail races of Southern companies. In any event, the use of marginal replacement fuel cost for dispatch will not be implemented if the FERC orders that such implementation is subject to refund.

Please indicate your agreement with the terms of this letter agreeaenr by signing below and returning it to the writer. Southern Cccpany Services, Inc., on behalf of the Southern electric system, will file this letter agreement with the FERC as a change in a practice under a rate schedule, and will notify you of the

Hr. M. H. Phillips
April 25, 1990
Page 4

date that the marginal replacement fuel cost procedure will be implemented.

Sincerely,

Robert O. Usry

Accepted by:
Date: 4-30-90

Attachment 1

1

## Guidelines for Determination of Marginal Replacement Fuel Prices

| | |
|---|---|
| Independent | The Forecast Team will have the responsibility and authority to establish marginal replacement fuel prices. |
| oversight | At least one operating company representative should be present at the price forecast team meetings. The responsibility to attend these meetings will be rotated between operatinq companies on a monthly basis. |
| Frequency | Marginal replacesent fuel prices will be developed monthly. |
| Price | The marginal replacement fuel price will be on a delivered $/MMBtu basis, rounded to the nearest cent, that reflects the cost of replacing the desired tonnage. |
| Tonnaqe | The desired tonnage used to determine marginal replacement fuel pricing will be twenty percent of the projected monthly burn or the equivalent of a ten percent capacity factor, whichever is greater. |
| True Cost | Marginal replacement fuel prices will include true variable cost and should not include any sunk cost. |
| Gas/Oil | Marginal replacement fuel prices will be based on the volume of gas/oil necessary to satisfy 100% of the projected monthly burn. Marginal gas/oil prices may be chanced during the nonth if a significant actual price change occurs. |
| Timing | Monthly marginal replacement fuel prices for all plants will be developed by the 3rd Friday of each month (15th - 21st). |
| Exception | The Southern Company Services Price Forecast Team will have the authority to decide on any exceptions as they arise. |
| Forecast lean | The Manager of Southern Company Services Procurement and Planning will have the, responsibility to utilize the resources of his organization and produce the monthly marginal replacement fuel price forecast given the above guidelines. |

Southern Company Services. Inc.
Post Office Box 2625
Birmingham. Alabama 35202
Telephone (205) 870-6462

William K. Newrnan
Vice President
Operating and Planning Services

the southern electric system

May 25, 1994

Mr. P. C. Henry
Senior Vice President
Florida Power Corporation
3201 34th Street
St. Petersburg, Florida 33711

**RE: REVISION IN FUEL ACCOUNTING PROCEDURES AT PLANT SCHERER**

Dear Mr. Henry:

As recently discussed with representatives of Florida Power Corporation ("FPC"), the co-owners of the Robert W. Scherer Steam Electric Generating Plant ("Plant Scherer") in an effort to reduce plant fuel costs, have decided to burn sub-bituminous coal in certain units at the plant. As a result of this decision, certain fuel accounting procedures are being revised to allow the use of both sub-bituminous and bituminous coal at Plant Scherer. Under the new procedures, fuel at Plant Scherer is accounted for on a BTU basis, and a generation equivalent BTU ("GEBTU") factor is applied to sub-bituminous coal to reflect differences in thermal efficiency between bituminous and sub-bituminous coal. On behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company (collectively referred to as "Southern Companies"), we are writing to clarify and explain the effect of these procedures on the Unit Power Sales Agreement dated July 19, 1988 between FPC and Southern Companies (the "UPS Agreement").

The need to adopt BTU accounting and the GEBTU factor arose out of the decision to burn sub-bituminous coal at Plant Scherer. The Plant Scherer co-owners decided to continue burning bituminous coal in Units 1 and 2 and to begin burning sub-bituminous coal in Units 3 and 4. Although only two units will burn sub-bituminous coal, the Plant Scherer co-owners decided that all plant participants will share in the benefits and burdens of that coal. To this end, the Plant Scherer co-owners will share the cost savings resulting from the use of sub-bituminous coal and will share the investment carrying costs of modifying Units 3 and 4 to allow them to burn such coal. The co-owners will also share various incremental operation and maintenance costs resulting from the use of sub-bituminous coal, as necessary to accomplish an equitable cost sharing.

May 25, 1994
Page 2

The heating characteristics of sub-bituminous and bituminous coal are significantly different, with bituminous coal having more BTUs per pound. In addition, sub-bituminous coal has a higher moisture content and thus burns less efficiently than bituminous coal. This additional moisture content results in: (i) losses due to increased latent heat evaporation (the additional BTUs required to convert the moisture to steam that goes up the stack); (ii) losses in boiler efficiency due to slagging characteristics of fuel; and (iii) additional station service required for pulverizers and fans to move more of the coal to the burner. Testing at Plant Scherer indicated that, primarily due to the higher moisture content of the sub-bituminous coal, burning a given amount of sub-bituminous coal produced about 95% of the energy output as burning bituminous coal with an equivalent amount of BTUs. These different heating characteristics require that fuel at Plant Scherer must be accounted for on a BTU basis and that sub-bituminous BTUs must be discounted to be made equivalent to the energy output of bituminous BTUs.

In order to equate the thermal efficiency of sub-bituminous and bituminous coal, a GEBTU factor has been developed. This GEBTU factor represents the additional amount of sub-bituminous BTUs necessary to equal the thermal efficiency of bituminous BTUs (i.e., approximately 5%). The GEBTU factor will be reviewed periodically and, if appropriate, adjusted prospectively to reflect differences in thermal efficiencies. By discounting the BTU content of sub-bituminous coal by the GEBTU factor, the two types of coal effectively have equal thermal efficiencies.

When sub-bituminous coal is received, the BTUs are discounted by the GEBTU factor. The discounted sub-bituminous BTUs are then charged to the purchasing Plant Scherer co-owner's respective fuel account. The cost of the discounted sub-bituminous BTUs receipts and the cost of the bituminous BTUs receipts are used to develop each stockpile participant's Plant Scherer weighted average cost per BTU ($/BTU). Thus, the cost of fuel ($/BTU) for all the Plant Scherer Units reflects the lower sub-bituminous coal costs and all Plant Scherer co-owners share in the savings.

When the sub-bituminous coal is actually burned, the burn analysis (BTUs consumed) is discounted by the GEBTU factor. The discounted BTUs are used to determine burn expense and are deducted from the Plant Scherer co-owner's respective fuel account. Without this adjustment, the burn expense related to the Plant Scherer Units burning sub-bituminous coal would be overstated. The Plant Scherer co-owners have adopted the above-described fuel accounting procedures effective October 1, 1993.

May 25, 1994
Page 3

The adoption of the revised fuel accounting procedures will have an impact on the fuel accounts from which energy prices are determined. The Plant Scherer Common Coal Stockpile will continue to be used for determining Base Energy Rates ("BERs") and Normalized Energy Rates ("NERs") under the UPS Agreement. With respect to the BERs under the UPS Agreement, the fuel cost component for a unit will be calculated using the Plant Scherer Common Coal Stockpile weighted average cost per BTU based on the cost of bituminous BTU inventory and the cost of sub-bituminous GEBTU inventory. The fuel cost component for a unit of the NERs under the UPS Agreement will also be based upon the Plant Scherer Common Coal Stockpile weighted average cost per BTU reflecting the cost of bituminous BTU inventory and the cost of sub-bituminous GEBTU inventory. The heat content of the fuel used in the calculation of the NERs will be based upon the actual BTUs consumed, either bituminous or sub-bituminous. It would be incorrect to discount the burned sub-bituminous BTUs by the GEBTU factor because the lower thermal efficiency is reflected in the higher heat rates of the units burning sub-bituminous coal used in the calculation of the NERs.

If you agree with this proposed revision, please indicate your agreement by signing below and returning this letter agreement to the undersigned.

Sincerely,

William K. Newman

William K. Newman, Vice-president
Operating and Planning Services

ACCEPTED BY:

P C Henry

P. C. Henry, Senior Vice President

DATED: ____________________

Southern Company Services
Post Office Box 2625
Birmingham. Alabama 35202
Telephone (205) 870-6462

William K. Newman
Vice President
Operating and Planning Services

the southern electric system

July 10, 1995

Mr. M. B. Foley
Vice President
Florida Power Corporation
3201 39th Street
St. Petersburg, Florida 33711

**RE: REVISION OF FUEL ACCOUNTING PROCEDURES AT PLANT MILLER**

Dear Mr. Foley:

Alabama Power Company ("APCo"), the majority owner and operator of the James H. Miller, Jr. Steam Electric Generating plant ("Plant Miller"), in an effort to reduce plant fuel costs, has decided to burn sub-bituminous coal in Plant Miller's Unit 4. Sub-bituminous coal is a less expensive fuel source than bituminous coal. Due to its physical characteristics, however, sub-bituminous coal should be stored and burned separately from bituminous coal.

Because sub-bituminous coal is less expensive than bituminous coal, and because sub-bituminous coal will be burned initially only at Plant Miller's Unit 4, certain fuel accounting procedures are being revised to allocate the benefits and costs of the lower cost sub-bituminous coal equally across all units at Plant Miller. If market conditions in the future so dictate, APCo may take further advantage of sub-bituminous coal and, thus, may convert additional units to sub-bituminous capability. In such an event, the accounting procedures set forth herein would apply in an analogous fashion.

Under the new procedures, fuel at Plant Miller is accounted for on a BTU basis, instead of on a tonnage basis, and a generation equivalent BTU ("GEBTU") factor is applied to sub-bituminous coal to reflect differences in thermal efficiency between bituminous and sub-bituminous coal. On behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company (collectively referred to as "Southern Companies"), we are writing to clarify and explain the effect of these procedures on the Unit Power Sales Agreement dated July 19, 1988 ("UPS Agreement") between FPC and Southern Companies.

The need to adopt BTU accounting and the GEBTU factor arose out of the decision by Alabama Power Company ("APCo") to burn sub-bituminous coal at Plant Miller. APCo has selected Plant Miller's Unit 4 initially to burn sub-bituminous coal for various

July 10, 1995
Page 2

engineering and operational reasons. Although only one unit initially will burn sub-bituminous coal, APCo believes that the reduced fuel cost resulting from that burn should be allocated evenly across all Plant Miller units. Such an allocation recognizes that, absent the special characteristics of sub-bituminous coal, the benefits of lower price coal acquisitions ordinarily would be spread evenly across all units. To this end, all Plant Miller units will be allocated a fair share of the cost savings resulting from the use of sub-bituminous coal and, correspondingly, will be allocated a fair share of the investment costs of modifying Unit 4 to burn such coal. All units will also share various incremental operation and maintenance ("O & M") costs resulting from the use of sub-bituminous coal at Unit 4, as necessary to accomplish an equitable cost sharing among units. On an ongoing basis, Plant Miller personnel will evaluate all O & M projects to determine if the project is primarily attributable to burning sub-bituminous fuel or if the project is considered normal unit operation cost. If a project is determined by Plant Miller Personnel to be primarily attributable to burning sub-bituminous fuel, the cost of such project will be allocated to all units at Plant Miller. Therefore, FPC's share of these costs will be baeed on a capacity entitlement allocation of its share of Plant Miller Unit 4 as a function of the total capacity at the plant.

The heating characteristics of sub-bituminous and bituminous coal are significantly different, with sub-bituminous coal having less BTUs per pound. Sub-bituminous coal also has a higher moisture content and thus burns less efficiently than bituminous coal. This additional moisture content results in: (i) losses due to increased latent heat evaporation (the additional BTUs required to convert the moisture to steam that goes up the stack); (ii) losses in boiler efficiency due to slagging characteristics of fuel; and (iii) additional station service required for pulverizers and fans to move more of the coal to the burner. Testing at Plant Miller indicates that, primarily due to the higher moisture content of the sub-bituminous coal, burning a given amount of sub-bituminous coal produced about 95% of the energy output as burning bituminous coal with an equivalent amount of BTUs. These different heating characteristics require that fuel burned at Plant Miller be accounted for on a BTU basis and that sub-bituminous BTUs must be discounted to be made equivalent to the energy output of bituminous BTUs.

In order to equate the thermal efficiency of sub-bituminous and bituminous coal, a GEBTU factor has been developed. This GEBTU factor represents the additional amount of sub-bituminous BTUs necessary to equal the thermal efficiency of bituminous BTUs (approximately 5%). The GEBTU factor will be reviewed periodically and, if appropriate, adjusted prospectively to reflect differences in thermal efficiencies. By discounting the BTU content of sub-

July 10, 1995
Page 3

bituminous coal by the GEBTU factor, the two types of coal effectively have equal thermal efficiencies.

When sub-bituminous coal is received, it is segregated from bituminous coal and positioned for utilization at Unit 4. The amount of coal received will continue to be accounted for on a tonnage basis and will be priced for total plant burn cost at an average cost per ton for the designated providing stockpile. When the sub-bituminous coal is actually burned, the burn analysis (BTUs consumed in generation) is discounted by the GEBTU factor prior to determining the total BTUs consumed by all plant units. Without this adjustment, the burn expense related to Unit 4 (burning sub-bituminous coal) would be overstated. The total BTUs consumed is then determined by adding bituminous and adjusted sub-bituminous BTUs consumed by each unit. The resulting total BTUs consumed is then divided into the previously determined total plant burn cost. The resulting cost per BTU is then applied to the BTUs consumed by each unit, as adjusted by the GEBTU factor, which results in a cost per unit or "Unified BTU Cost." The Unified BTU Cost will equal the total cost formerly determined by utilizing an average cost per ton. The total of the Unified BTU Cost for each unit will serve as the "cost" of fuel under the UPS Agreement. APCo has adopted the above-described fuel accounting procedures effective January 1, 1995.

The adoption of the revised fuel accounting procedures will have an impact on the fuel accounts from which energy prices are determined. The combined Plant Miller stockpile will continue to be used for determining Base Energy Rates ("BERs") and Normalized Energy Rates ("NERs") under the UPS Agreement. With respect to the BERs under the UPS Agreement, the fuel cost component for a unit will be calculated using the Plant Miller Unified BTU Cost based on the cost of bituminous BTU burned and the cost of sub-bituminous GEBTU burned. The fuel cost component for a unit of the NERs under the UPS Agreement also will be based upon the Plant Miller Unified BTU Cost reflecting the cost of bituminous BTU burned and the cost of sub-bituminous GEBTU burned. The heat content of the fuel used in the calculation of the NERs will be based upon the actual BTUs consumed, either bituminous or sub-bituminous. It would be incorrect to discount the burned sub-bituminous BTUs by the GEBTU factor because the lower thermal efficiency is reflected in the higher heat rates of the units burning sub-bituminous coal used in the calculation of the NERs.

Based on an analysis we have conducted, the net impact of these changes for use of sub-bituminous coal should result in an economic benefit to FPC. This analysis is based on simulation and estimates of future costs, and as these factors change, the overall results will be affected. To take full advantage of this benefit,

July 10, 1995
Page 4

it is necessary to implement the fuel accounting procedures we have described herein.

If you agree with this proposed revision, please indicate your agreement by signing below and returning this letter agreement to the undersigned.

Sincerely,

William K. Newman

William K. Newman, Vice-president
Operating and Planning Services

ACCEPTED BY:

M B Foley Jr.

M. B. Foley, Vice President

DATED: 7/20/95

Southern Company Services, Inc.
Post Office Box 2625
Birmingham, Alabama 35202-2625
Telephone (205) 870-6011

Southern Company Services
a subsidiary of The Southern Company

September 10, 1996

Mr. M. B. Foley
Senior Vice President
Florida Power Corporation
3201 34th Street South
St. Petersburg, FL 33711

SETTLEMENT OF CERTAIN COST OF CAPITAL ISSUES

Dear Mr. Foley:

As you know, Florida Power Corporation ("FPC") purchases capacity and energy from Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company (collectively referred to as the "Operating Companies") by and through their agent, Southern Company Services, Inc. ("SCS") under the Unit Power Sales Agreement dated July 19, 1988, which has been amended from time to time ("UPS Agreement"). This letter agreement addresses an issue raised during an audit conducted by Florida Power & Light during 1993, concerning the practices and methodologies used by the Operating Companies to recognize partial redemption of securities in the derivation of cost of capital under the UPS Agreements. The Operating Companies, on their own accord, also have reconsidered their past practice of not reflecting the results of subsequent generation refundings in cost of capital calculations.

After studying these issues, FPC, the Operating Companies, and SCS agree to the inclusion of partial redemptions of securities and the means by which subsequent generation refundings will be reflected in cost of capital calculations under the UPS Agreement.

***Partial Redemption of Securities and Subsequent Generation Refundings***

The UPS Agreement contains negotiated formula rates set forth in a "manual" appended to the UPS Agreement and are integral thereto. The formula rates are designed to recover specified costs associated with the particular capacity dedicated to the sale. One element of the capacity charge is the cost of capital. Cost of capital calculations are, in turn, based on the cost of securities issued to finance construction of dedicated facilities, determined as of the date such facilities were placed into commercial operation.

Mr. M. B. Foley
September 10, 1996
Page 2

Under the UPS Agreement, the cost of capital for dedicated facilities is included in the development of capacity charges for transmission and generation facilities. The UPS Agreement addresses how cost of capital is adjusted to reflect the redemption of securities' but does not contemplate adjusting cost of capital to reflect the effects of partial redemption of securities. Heretofore, adjustments have been made by the Operating Companies only when securities were completely redeemed. The absence of specific reference to partial redemption in the formula rates has lead to discussions over the proper procedures and methodologies that should have been used by the Operating Companies in computing cost of capital under the UPS Agreement.

Upon their own review of methodologies and procedures applied to calculate cost of capital under the UPS Agreements, the Operating Companies have reconsidered their practice (dating to 1992 for Georgia Power Company and Gulf Power Company and 1993 for Alabama Power Company) of not reflecting subsequent generation refundings in cost of capital calculations.[2] The Operating Companies have determined that the effect of subsequent generation refundings should be reflected in cost of capital under the UPS Agreement.

In resolution and closure of the above-described partial redemption or retirement of securities and subsequent generation refunding issues, the Operating Companies will issue a credit to FPC. Said credit shall be the sum of (i) the difference between (a) the capacity payments made by FPC, beginning January 1, 1994 and ending with the last capacity payment prior to the acceptance of this amendment by the FERC, and (b) the capacity payments over the same period recalculated following the methodologies set forth in an Amendment to the UPS Agreement, for partial redemption or retirements of securities and subsequent generation refundings occurring on or after February 12, 1987; and (ii) interest on said amounts accrued in accordance with the UPS Agreement. For example, the total amount of the credit, including interest, is estimated to be $1,110,536, as of March 31, 1996. Said recalculations shall follow the methodologies set forth in an Amendment to the UPS Agreement, as discussed below.

Further, in resolution of the above-described partial redemption and subsequent generation refunding issues, the parties shall execute an Amendment to the UPS Agreement setting forth revised methodologies for retirement and/or redemption of securities and subsequent generation refundings. Said amendment shall set forth

[1] The methodology is set forth in Section C2.2.19 of the manual to the UPS Agreement.
[2] "Subsequent generation refundings" are securities issued to retire or redeem securities that themselves represented refundings of prior issues.

Mr. M. B. Foley
September 10, 1996
Page 3

revisions to the UPS Agreement's Manual, Section C2.2.19. The Amendment is attached hereto, incorporated herein by reference, and shall be made effective prospectively on the condition that it is accepted without material modification. The Amendment shall be filed by SCS on behalf of the Operating Companies for review by FERC under the "just and reasonable" standard of Section 205 of the Federal Power Act. FPC agrees to actively support FERC acceptance of the Amendment as filed.

Upon FERC acceptance of this letter agreement and the Amendment without material modification, the Operating Companies will credit charges under the UPS Agreements, as detailed above and will make their best efforts to reflect the credit in their next issued invoice to FPC for capacity under the UPS Agreements. Interest shall accrue on said sum in accordance with applicable UPS Agreements.

If you agree with the content of this letter, please indicate your agreement by signing below and returning to the under signed.

Sincerely,

W. L. Marshall, Jr., Director
Wholesale Merchant Functions

ACCEPTED BY;

Florida Power Corporation

Dated:

**ECO OF SULFUR DIOXIDE LOWA COSTS**
**IN FEI ENERGY REGULATORY OMMIS RATES**

## I. INTRODUCTION

This background paper explains how and why, after January 1, 1995, the Southern Companies (Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company) will recover the replacement cost[1] of sulfur dioxide allowances used in association with the generation and sale of electric energy for resale. After reviewing the requirements of Title IV of the Clean Air Act Amendments of 1990 ("CAA Amendments" or the "Act") and explaining the impact of the CAA Amendments on the Southern Companies, this paper will briefly describe the Southern Companies' CAA Amendments compliance plan.

This paper also provides information concerning the methods by which the Southern Companies will reflect the value of sulfur dioxide emission allowances used in each of three types of transactions subject to Federal Energy Regulatory Commission ("FERC") jurisdiction: 1) intercompany power exchanges governed by the Southern Company System Intercompany Interchange Contract ("ICC"); 2) coordination power sales made with non-affiliated neighboring electric utilities ("Coordination Sales"); and, 3) power sales under unit power sale agreements ("UPS Agreements") with several Florida utilities.

In keeping with the intent of the CAA Amendments to create a free and open market for SO, emission allowances and to foster least-cost compliance with Title IV, the Southern Companies are proposing that all purchasers of incremental energy reimburse the seller either by paying in cash the replacement cost of expended emission allowances or by returning equivalent emission allowances to the seller of energy under a FERC jurisdictional agreement.

[1] As used in this paper, "replacement cost" connotes the potential incremental cost of replacing an allowance at the time of an energy transaction. As noted by the Edison Electric Institute in its recent Petition for Statement on Ratemaking Treatment of Emission Allowances in Coordination Transactions, Docket No. PL95-1-000, the Commission has accepted incremental cost as the correct method to determine cost where any other method would result in over or under recovery, or an inefficient outcome. For the reasons set forth herein, the Southern Companies believe that the consistent use of the "replacement cost" of emission allowances in incremental energy pricing is an economically and environmentally efficient result.

## II. BACKGROUND ON THE CLEAN AIR ACT AMENDMENTS OF 1990

In 1990, the Congress enacted the Clean Air Act Amendments.[2] Long anticipated and much debated, the Act is the most comprehensive and far-reaching environmental statute ever enacted. While the goal of the acid deposition title (Title IV) -- to reduce emissions of $SO_2$ -- is not novel, the marketable allowance system instituted in that title ties the electric utility industry together in entirely new ways. In the past, the industry may have shared common concerns about clean air regulations, but, in the end, each electric utility faced the costs and consequences of clean air regulation alone.

Under the regime established by the CAA Amendments, it is difficult to conceive of any electric utility transaction that will not be affected by the new sulfur dioxide emission allowance provisions of the acid deposition title. A power producer may not be able to meet the emission reduction requirements without taking into account the plans and activities of other utilities or power producers. In power sales, in pool operations, in sales of facilities, and in serving existing customers, a utility will have to take into account the Act's allowance requirements. In addition, just as under the Clean Air Act Amendments of 1977, a large number of utilities may have to install and operate pollution control devices or, in many cases, purchase lower sulfur fuel.

### A. Summary of Title IV

Title IV is intended to reduce annual emissions of sulfur dioxide in the 48 contiguous states and the District of Columbia by ten million tons from 1980 emission levels. Under the Act, emissions of $SO_2$ are ultimately controlled so that emissions from all utilities do not exceed an annual aggregate of 8.9 million tons. To accomplish this goal, the Act provides a two phased program of reductions.

For Phase I, the Act identifies 110 plants -- those emitting over 2.5 pounds of sulfur dioxide per MBtu of fuel heat input -- and mandates that by January 1, 1995, annual sulfur dioxide emissions from the plants be reduced by approximately 2.5 to 4.5 million tons. The emissions limitations in Phase II, on the other hand, capture virtually every existing and new steam-electric utility unit in the 48 contiguous States and effectuate the 10 million ton reduction in annual sulfur dioxide emissions,

In general, affected utility units in Phases I and II have emissions limitation obligations, monitoring and reporting

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[2] Clean Air Act Amendments of 1990, S. 1630, 101st Cong., 2nd Sess., 104 Stat. 2399, P.L. No. 101-549.

requirements, permitting requirements, allowance allocations, and excess emissions liabilities.

**B. The Allowance *System***

A "utility unit" can be an "affected unit" and, therefore, subject to the $SO_2$ caps of the Act.[3] To comply with the Act, a power producer has a range of options. It can shut-down or reduce the output from a high emitting unit, install emission control technologies, switch to "cleaner" fuels, and/or rely upon the emission allowance system to provide offsets for emissions at a facility.

A power producer must hold emission allowances equal to the tons of $SO_2$ emitted from each of its units. Through the system of marketable allowances, the $SO_2$ reduction program is intended to maximize the range of choices that operators have in complying with the emissions limitation requirements. To reduce compliance costs and increase flexibility, electric utilities across the country are relying upon the sulfur dioxide emission allowance trading system to obtain additional emission allowances and to meet the compliance goals of the Act.

As noted, the Act specifies that an emission allowance is a limited authorization to emit, during or after a specified calendar year, one ton of $SO_2$.[4] Once created, an annual allowance does not expire until used. Thus, for example, an allowance allocated to an existing unit under the Act in 1996 may be "banked" and used to offset one ton of $SO_2$ emissions during the year 2001.

Emission allowances are issued to the owners and operators of existing utility units. The Act specifically states that an emission allowance does not constitute a property right and may be limited or terminated without compensation from the government.[5] At the same time, emission allowance transfers are supposed to carry out the "full menu" of prerogatives enjoyed by parties to conventional commercial contracts. In other words, parties will be able to transfer emission allowances between and among themselves through commercial arrangements such as sales agreements and exchanges of emission allowances for electric power or capacity. The Act contemplates that emission allowance holders will be able to transfer them freely:

> Allowances, once allocated to a person by the Administrator, may be received, held, and

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[3] Title IV, Section 402(17)(A), 42 USC 7651a.

[4] Title IV, Section 402(3), 42 USC 7651a.

[5] Title IV, Section 403(f), 42 USC 7651b.

> temporarily or permanently transferred in accordance with this title and the regulations of the Administrator. . . .[6]

The freedom granted the designated representative to transfer a given unit's emission allowances is indicative of the fact that Congress intended emission allowances to be transferred at their market value:

> . . . the allowance system is intended to maximize the economic efficiency of the program both to minimize costs and to create incentives for aggressive and innovative efforts to control pollution. In formulating regulations the Administrator should be mindful that to exploit the efficiencies afforded by the allowance system, parties will transfer them between and among themselves pursuant to a wide variety of commercial arrangements such as under leases, sales agreements and exchanges between emissions and electric power or capacity. Ownership of allowances by brokers, investors and other market makers will maintain fluidity in the allowance market, link ultimate buyers with original sellers and facilitate rational pricing.

150 Cong. Rec. S16980 (daily ed. October 27, 1990) (statement of Sen. Baucus) (emphasis added). Utilities to whom emission allowances are issued are thus supposed to be "market makers." While EPA will allocate emission allowances to utilities at no cost, the actual price of emission allowances is determined in part by the cost of available control alternatives to affected sources. Thus, "affected sources unable to install pollution control equipment or other control options for less than the cost of purchasing allowances will be potential buyers of allowances."[7] Because emission allowances are a valuable commodity that can be bought and sold in a national market, federal regulators should permit utilities to recover from wholesale customers the price of replacing emission allowances used in energy transactions.

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[6] Title IV, § 403(f).

[7] "Overview and Discussion of the Key Regulatory Issues in Implementing the Electric Utility Provisions of the Clean Air Act Amendments of 1990," *An Interim Report*, The National Regulatory Research Institute, p. iii, (June 1991).

C, Nitrogen Oxides Control and "Substitution Unit" Background

Title IV of the CAA Amendments, in conjunction with other CAA requirements, also calls for a nationwide 2-million ton reduction in NO, emissions by the year 2000. A significant portion of this reduction will be achieved by Title IV-affected coal-fired electric utility boilers. These boilers will be required to meet new emission requirements that will be implemented in two phases for two groups of boiler types.

In **1995**, annual NO, emission rates must be met, individually or on average, by all coal-burning Phase I dry bottom, wall fired and tangentially fired boilers, which are known as Group 1 boilers. Compliance with the annual SO, and NO, limits will be determined by continuous emissions monitoring systems ("CEMs"), which must have been in service by November **15, 1993.** The Act requires installation of this new technology to measure SO, emissions along with other emissions at the stack of each affected unit.

All coal-fired Phase II units larger than 25 MW also must meet a yet to be determined NO, emission rate by January **1**, 2000, and have CEMs installed by January 1, **1995.** The CAA Amendments require EPA to set the Phase II NO, rates by January **1, 1997** for so-called Group 2 electric utility boilers (wet bottom, wall-fired, cyclone, cell-burners and all other unit types). In **1997**, EPA may revise the NO, limits for Group 1 boilers based on the availability of more cost-effective NO, burner technology. If Group 1 limits are revised, the new limits will affect only Phase II Group 1 boilers and will not be retroactive to Phase I Group 1 boilers.

The Act permits intra- and intercompany averaging of NO, emissions from affected boilers based on annual input per boiler and total annual NO, emissions. Companies may also grandfather Phase I Group **1** boilers under the lower Phase I NO, limitations by designating that unit as a Phase I substitution unit, which also makes the unit subject to Phase I SO, requirements. Thus, many Phase I-affected utilities are considering which of their Phase II units can be brought into the acid rain program early on a cost-effective basis.

Typically, the central reasons for the use of the substitution units as a part of a compliance strategy are to minimize or eliminate SO, allowance surrender resulting from Phase I unit reduced utilization' or more importantly to assure NO, compliance

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[8] The **1990** amendments do not impose a cap on aggregate utility SO, emissions during Phase I **(1995-2000).** In the course of the legislative debate, however, a number of groups were concerned that utilities would deliberately or inadvertently circumvent the goals of the Clean Air Act Amendments simply by reducing

at least cost in Phase I. Substitution units that were in operation during the so-called baseline years (1985-87) are granted emission allowances based on historical baseline emissions and will consume emission allowances during the years that they are deemed to be substitution units. Some newer substitution units (those that were not in operation during the baseline years) will not be allocated any emission allowances and will have to secure emission allowances from other sources in order to operate.

## III. SOUTHERN COMPANY COMPLIANCE WITH THE CLEAN AIR ACT AMENDMENTS

As noted above, the CAA Amendments mandate $SO_2$ and $NO_x$ emission reduccions from fossil fuel-fired generating units. These reductions are to be implemented in two phases. Phase I begins on January 1, 1995, and continues until December 31, 1999, when Phase II begins. Of the 110 plants named in Phase I, 8 plants are owned and operated by the Southern Companies. All other fossil fuel fired generating units owned by the Southern Companies will be included in Phase II.

As discussed above, one option available to Southern Companies to aid it in attaining "least-cost compliance" is to bring Phase II units into compliance with Phase I emission standards five years early. This is called "substitution" and exercise of the substitution option does not release the specially-identified Phase I affected units from their compliance obligations. Instead, by substituting Phase II units in Phase I, Southern Companies ensure that units that would be costly to bring into compliance are included in the least stringent phase of compliance, which is Phase I. The use of substitution units will also eliminate the allowance surrender requirements associated with reduced utilization.

For $NO_x$ compliance, the Southern Companies efforts are concentrated on installation of low-$NO_x$ burner systems as the preferred method of achieving compliance at minimal costs. The Southern Companies have filed applications with EPA to substitute 32 Phase II units as Phase I units. If the applications are approved, the units become Phase I units for $NO_x$ control purposes and will be grandfathered for life, thereby, avoiding possible stricter $NO_x$ regulations that EPA may impose in the future. Moreover, by bringing some units into Phase I, the Southern Companies will be able to meet the Act's $NO_x$ requirements through averaging emissions for the five Operating Companies through three $NO_x$ averaging plans. The three Phase I $NO_x$ averaging plans for 1995

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utilization of "affected" units during Phase I. As a result, Congress inserted the "reduced utilization" provision into the compliance plan requirements of the Act that requires utilities designate so-called compensating units or to surrender allowances that result from reduced utilization.

include a plan for Alabama alone, a plan for Georgia and Savannah and a plan for Gulf and Mississippi. The EPA rules allow for separate averaging plans in each year of Phase I.

For $SO_2$ compliance in Phase I, the Southern Companies generally have chosen to switch to lower sulfur coal. Specifically, Southern Companies' $SO_2$ compliance plan was developed through systematic consideration of various options, including fuel switching to natural gas, purchasing $SO_2$ emission allowances, flue gas desulfurization, and unit retirement. In fact, as a part of the strategy development a least-cost base strategy and three alternate cases were developed.

The selected base strategy allows $SO_2$ emission allowance transactions internal and external to the Southern Companies as necessary in an unrestrained market to allow a minimum-cost solution. Thus, one of the key assumptions of the least-cost strategy chosen by Southern Companies is that there will be a viable emission allowance market from which to purchase emission allowances, if necessary.

The projected selling price of emission allowances will determine the maximum cost that the Southern Companies will be willing to incur before purchasing emission allowances from the market. For this reason, the base strategy only included those compliance options that had a value less than the projected market value of emission allowances. The least-cost compliance plan for the Southern Companies is composed of fuel switching to lower sulfur coals, supplemented by allowance purchases by each operating company in Phase 11.

As noted, for Phase II compliance, the Southern Companies project further fuel switching and the purchase of $SO_2$ emission allowances will be the least-cost compliance options. The current projected cost of CAA Amendment compliance for the Southern Companies is **$2.054** billion **(1992** Net Present Value) in revenue requirements between **1992** and **2016.** (Clean air revenue requirements are defined as all costs associated with implementing the compliance strategy).

## IV. <u>INTERCOMPANY INTERCHANGE CONTRACT</u>

The IIC is the mechanism through which the individual Southern Companies share temporary surpluses or deficits of capacity that occur over time and account for energy transactions resulting from centralized economic dispatch of their generating units. Energy transactions among the constituent Southern Companies are accounted for on an hour-to-hour basis. The day-to-day operation of the Southern Companies pool is based upon the economic energy dispatch, which assures, through on-line computer control that available generation is dispatched so as to choose the most economical marginal generation available to serve the total system obligation at any given time.

Under the provisions of the IIC, each of the Southern Companies is able to retain its lowest-cost energy resources to serve its own native load customers, plus whichever of its resources that may have been operating out of economic dispatch for purposes such as, but not limited to, unit or area protection or voltage control. To the extent one of the individual Southern Companies' generation exceeds its native load, that energy is sold to the pool under the IIC for purchase by another company whose generation is less than its native load. Each individual Southern Company sells energy to the pool and purchases energy from the pool based upon the southern electric system's territorial incremental cost of those generating resources providing such energy to the pool. This incremental cost is currently composed of incremental fuel cost, variable operation and maintenance expenses, fuel handling expense, and a provision for losses.

Again, the operation of Phase I affected units requires the consumption of $SO_2$ emission allowances. Although specified allotments of emission allowances will be issued annually by the EPA to the operators of fossil-fired generating units, emission allowances used to produce energy available to the Southern Companies' pool will have an effective opportunity cost or value to each company because they can be bought, sold and traded on an open allowance market.

State regulators, including the Georgia Public Service Commission in its recent examination of Georgia Power Company's CAA Amendments compliance efforts, properly characterized a transfer of emission allowances between sister companies without adequate compensation would represent the provision of a subsidy from one operating company to another. Consumption of an emission allowance in the generation of electric energy would cause a sister operating company at some point in time either to purchase another emission allowance, to forego the sale of emission allowance on the market, or take further emission reduction emission allowances elsewhere on its system. In other words, the consumption of emission allowances eventually causes an increase in revenue requirements vis-a-vis nonconsumption. Thus, the Keystone Center's Interim Report, the "Keystone Dialogue On State Regulation of Allowance Trading," published in February, 1992, concluded that regulators:

> [s]hould recognize that a cost of compliance will need to be incorporated into the economic dispatch of a utility's generating resources. $SO_2$ emissions represent a true cost of utility operation. Compliance costs for dispatch should be based on the market price of allowances unless there are significant distortions in the allowance markets. The

> commission should recognize that there is a need for consistency of treatment across company and state lines to facilitate economic power pool operations and other bulk power transactions.

Keystone Interim Report, p. 11.[9]

Keystone's recommended approach is consistent with the principles of economic dispatch. If the variable cost of emission allowances is ignored in economic dispatch for the Southern Companies, then a sub-optimal dispatch would result; that is, total revenue requirements would be higher than the minimum that could be achieved. Thus, beginning January 1, 1995, an $SO_2$ emission allowance replacement cost will also be included in the economic dispatch algorithm to account for the cost of $SO_2$ emission allowances consumed with each MWh of generation. The $SO_2$ emission allowance replacement cost for Phase I will be calculated as provided in Section VII herein. In that regard, both the $SO_2$ emission rate and the heat rate are unit-specific values. A single market value will be used for the $SO_2$ emission allowance replacement cost on all units."

Applying this emission allowance replacement cost to the system dispatch algorithm will operate clean units more and high-emitting units less. As long as the emission replacement cost accurately reflects the value of an emission allowance, the total production costs, including costs of emission allowances, are reduced. Application of the emission costs in dispatch will capture all emission reductions that can be achieved at or below the emission allowance replacement cost applied. Based on these principles, the replacement cost of emission allowances associated with Phase I units will be included in the energy price for a transaction under the IIC.

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[9] The Keystone Center is a non-profit organization that convenes and facilitates policy dialogues addressing complex and contentious public policy issues. In this Dialogue consensus was achieved regarding an overriding goal and principles and a recommended review process for state regulation of utility compliance with acid rain legislation. Participants represented: utilities, the consuming and environmental communities, and state and federal regulators.

[10] In Section VII of this paper, the Southern Companies outlined the standard procedure they will utilize to determine the monthly $SO_2$ replacement cost that will be used in system dispatch as well as for determining replacement costs in FERC-jurisdictional transactions.

Since proper valuation of equivalent allowances ensures that Southern Companies will be indifferent as between receiving dollars or allowances, the Southern Companies also propose to amend the IIC to provide that equivalent emission allowances can be traded among companies along with energy sales resulting from the IIC. Thus, €or example, if Company A sells generation from an affected unit to Company B and consumes emission allowances through its generation, then Company B may give emission allowances associated with Phase I units to Company A for all emission allowances consumed to provide energy.

## V. COORDINATION AGREEMENTS

The Southern Companies currently maintain coordination relationships with twelve neighboring utility systems. Agreements among and between Southern Companies and these neighbors provide an ongoing framework whereby the parties may, often on short notice, engage in transactions that enhance the reliability of their own service (such as emergency or short term purchases) or inure to the mutual benefit of the parties (such as economy purchases). The "coordination agreements" describe the points of interconnection between the parties' electrical systems and provide for their continued operation and maintenance. They also describe the terms and conditions of power supply, including provisions related to metering, billing and payment, responsibility and indemnification, inadvertent interchange, control of system disturbances, establishment of operating committees, and other matters involving the administration of the interconnected and coordinated operations.

Since passage of the Act, utilities must take allowance usage into account as they plan and operate their systems. In other words, when determining its dispatch, a utility shall attempt to minimize the sum of operating costs and emissions-related costs. The National Economic Research Associates' paper, entitled "The Effects of the 1990 Clean Air Act on System Dispatch and Marginal Costs," discusses how coordination customers should bear cost responsibility for clean air compliance:

> First, the criterion for determining system dispatch must change to include emissions-related as well as operating costs if a utility is to minimize its overall costs, Second, the marginal costs must take into account the emissions-related costs as measured by allowance prices. Finally, projections of prices for tradable emissions

allowances become as important as fuel price forecasts for determining system dispatch."

For these reasons, as well as the reasons discussed with respect to the IIC, the Southern Companies will amend their coordination agreements with non-associated companies to include a component for all Phase I affected units in the dispatch procedures and incremental energy cost determination for emergency power sales, short-term power sales, and economy energy sales. Specifically, those provisions in each of the Southern Companies' coordination agreements will be amended (or procedures changed) to provide that the incremental cost of energy will include an "emission allowance replacement cost" in addition to incremental fuel costs, system transmission losses and other such energy related costs.[12]

Provisions also will be made for allowing purchasers under the coordination agreements to provide compensation in the form of equivalent emission allowances on a monthly basis. Providing a power purchaser the option of providing equivalent allowances in lieu of dollars ensures that the power purchaser in a coordination arrangement is not obligated to pay the replacement cost of emission allowance determined by the power seller.

## VI. UNIT POWER SALES AGREEMENTS

The Southern Companies' UPS Agreements involve the sale of capacity from specific generating units along with an entitlement to schedule energy from the unit whenever the unit is available for operation. (The sale of unit power does not constitute a sale, lease, transfer, or conveyance of an ownership interest). Under the Southern Companies' UPS Agreements, energy must be supplied if the designated units are available and cannot be interrupted even if needed to serve territorial customers. Currently, there are six UPS Agreements between Southern Companies and Florida Power & Light Company (two agreements, executed in 1982 and 1988), the Jacksonville Electric Authority (two agreements, executed in 1982 and 1988), Florida Power Corporation (agreement executed in 1988), and the City of Tallahassee (contract executed in 1990). Southern Companies have also entered into transition energy agreements with

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[11] Wile, Ambrose, and Parmesano, n/e/r/a Working Paper #12, "The Effects of the 1990 Clean Air Act Amendments on System Dispatch and Marginal Costs," 7 (October, 1991).

[12] As noted in footnote 7, suwra, Section VII sets forth the standard procedure The Southern Company will utilize to determine the monthly SO,, replacement cost that will be used in coordination agreements as emission allowance as for determining replacement costs in other FERC-jurisdictional transactions,

FPL and JEA related to the sale of Georgia Power Company's Scherer Unit No. 4 ("Scherer 4 Transition Energy").

Currently, The Southern companies UPS units are Alabama Power Company's Miller Units #1-4; Georgia Power Company's and Gulf Power Company's Scherer Unit #3; and Georgia Power Company's Scherer Unit #4. The various UPS agreements contain a number of rate schedules. The complete list of such schedules is described below, Every UPS Agreement contains a base energy provision that recognizes the dedication of generation capacity to the particular purchaser, but not every UPS Agreement contains each of the other energy schedules outlined below. (For example, the City of Tallahassee agreement does not include a discretionary energy provision.)

**A. UPS Base Energy Sales**

Base energy constitutes energy scheduled from the UPS unit by an off-system customer.

**B. Unit Power Sales - Alternate**

Alternate energy is energy scheduled by the UPS customers from a UPS unit, but delivered from other sources available to the Southern Companies. Alternate energy is supplied whenever the economic dispatch procedures of Southern Companies determine that there are more economical resources to operate than the UPS unit. These "alternate" resources are then utilized by the Southern Companies to supply the energy.

**C. Unit Power Sales - Supplemental**

supplemental energy is energy scheduled by the UPS customers from a UPS unit, but delivered from other sources available to the system. When a UPS unit is unavailable, due to scheduled maintenance or a forced outage, supplemental energy is made available from other generating units owned or operated by the Southern Companies.

**D. Unit Power Sales - Discretionary**

Discretionary energy is energy that is made available under the UPS agreements for up to 10% of the capacity purchased and is delivered from other sources available to the Southern Companies. Therefore, discretionary energy allows the customer to schedule 110% of their capacity purchase at a given price if Southern Companies have the energy available.

**E. UPS Replacement Energy**

UPS Replacement Energy entitles UPS customers the option to purchase replacement energy at a lower cost in substitution for UPS energy that they might otherwise schedule under the base, alternate, and supplemental energy provisions of the UPS agreements. UPS Replacement Energy is priced at the incremental energy cost of the Southern Company's generating units. Moreover, any UPS Replacement Energy is credited toward the UPS customers' minimum annual utilization under the UPS agreements.

**F. Phase I Effects on UPS Agreements**

Each of the UPS units are Phase II affected units that would not be affected until 2000.[13] Thus, purchasers of power from the units would not normally be expected to provide emission allowances or compensation for emission allowances associated with the purchase of UPS Base Energy. Several of the Phase II UPS units have been identified, however, as potential "substitution" units.

Among the units under consideration as substitution units are Alabama Power Company's Miller Unit #4 and Georgia Power Company and Gulf Power Company's Scherer Unit #3, both of which are committed to providing service to Southern Companies wholesale unit power customers in Florida. Because these units were not in operation during the so-called baseline years, they would not be allocated any Phase I emission allowances. Thus, if these units are designated "substitution units," they will have to consume allowances obtained from other sources. In all likelihood, these units would serve as substitute units only for the year of 1395.

After careful consideration of the matter and after discussions with its UPS customers, the Southern Companies have decided to bear the replacement costs of emission allowances associated with the decision to include these UPS units in the 1995 substitution plan. (The Southern Companies have made this decision even though they believe they are otherwise entitled to recover such costs from the UPS customers.) This concession on the part of Southern Companies to its UPS customers is based on several considerations:

1) inclusion of these units as substitution units would contribute to reducing the cost of $NO_x$ compliance through a possible Southern Companies' $NO_x$ averaging plan, which would provide an economic benefit to all customers, not just UPS customers;

2) the choice of substituting in certain Phase II units was a $NO_x$-related decision made solely by the Southern Companies; and,

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[13] We would note that prior to January 1, 2000, further amendments with regard to the treatment of the Southern Companies' Unit Power Sales units will be necessary before those units become "affected units" under Phase II of the Act.

3) the substitution rules were developed late in the regulatory process and the final decision on whether any UPS units will be included as substitute units in the Southern Companies' $NO_x$ averaging plan will not be made until mid-1995.

Thus, in this specific case, the Southern Companies plan to exclude the emission allowance replacement cost component from the Base Enersv Rate calculation for Miller Unit #4 and Scherer Unit #3, if such units are designated as "substitution" units during Phase I.

With respect to eneruv sales other than UPS base energy, however, the incremental enersv cost for sales of UPS Replacement Enersv, Alternate Enersv, Supplemental Enersv, Discretionary Energy and Scherer 4 Transition Enersv, will be modified to include a component to recover emission allowance replacement costs associated with producing the enersv. In particular, UPS customers may experience changes in the cost of fuel due to the use of low sulfur coal at Phase I affected units and substitute units. As with all other customers, UPS customers will be given the option of providing equivalent emission allowances on a monthly basis or dollars to compensate for the use of allowances by Southern Companies to support incremental energy sales.

During Phase I, the Southern Companies' UPS customers of course will pay for some capital expenditures associated with compliance at the UPS units. For example, UPS customers are currently paying increased capital and O&M costs due to installation of continuous emission monitors at the UPS units. UPS customers also face potential increases in capital and OGM costs at the Scherer units due to $NO_x$ controls under Title I of the CAA Amendments.

## VII. PROCEDURE FOR DETERMINING THE MONTHLY $SO_2$ ALLOWANCE REPLACEMENT COST

### A. Method for Determining a Monthly $SO_2$ Allowance Replacement Cost

As discussed extensively, the CAA Amendments create a new operating input for all FERC-jurisdictional sales -- the $SO_2$ allowance. While Southern Companies propose to allow affiliates, coordination sales customers, and UPS customers to provide equivalent emission allowances to support energy transactions, the Companies recognize that customers will need a dependable measure of the replacement cost that each constituent company will use if an affiliate or customer chooses not to provide an actual replacement allowance. Thus, the Southern Companies have developed an auditable and initial procedure €or determining the "Monthly $SO_2$ Allowance Replacement Cost." That cost will be used to determine the incremental $SO_2$ costs of operating those units that are affected by the CAA Amendments.

The procedure for determining an emission allowance replacement cost will be approved by Southern Companies' Operating Committee and is subject to revision as appropriate based on operational and market experience. The incremental $SO_2$ cost of operating an affected unit will be calculated from three components: the replacement cost of the allowances, the heat rate of the unit and the $SO_2$ rate of the fuel being burned. The emission allowance replacement cost will be measured in $/allowance, the heat rate in Btu/kwh, and the fuel $SO_2$ rate in lbs $SO_2$/MBtu. Using the following definitions,

EC = Total Incremental $SO_2$ cost; $/MWh
AC = Allowance Cost; $/allowance (one allowance is equal to one ton of $SO_2$)
HR = Heat Rate, Btu/kwh
SR = $SO_2$ Rate for fuel, lb $SO_2$/MBtu

the incremental $SO_2$ emission allowance cost for a particular unit will be computed as

$$EC = AC \bullet (HR/1000) \bullet (SR/2000)$$

As can be seen, certain components such as the heat rate (HR) and the $SO_2$ rate for fuel (SR) must be inputs to the economic dispatch methodology in order to calculate the incremental $SO_2$ cost (EC). The Southern Companies plan to use an estimate of the $SO_2$ rate for fuel (SR) being burned in a given unit based upon the fuel contract specifications of the fuel delivered to a given plant. This data will be cross-checked against actual continuous emission monitoring data. When appropriate, the results of the cross-check will be factored into the determination of a unit's emission rate (SR), on a prospective basis.

The calculation above yields the incremental $SO_2$ cost component of producing the next megawatt hour of energy at a given unit. Again, the purpose of this procedure is to define the methodology for determining the Monthly $SO_2$ Allowance Cost component of the incremental $SO_2$ emission allowance replacement cost. The Monthly $SO_2$ Allowance Cost component will be computed from the average cost of purchasing an emission allowance from within a test block of 2500[14] emission allowances usable in the current year.

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[14] Approximately equal to the amount of emission allowances needed to support wholesale transactions under the IIC, Coordination Sales, and UPS Agreement.

The Southern Companies believe that emission allowance exchange markets provide the best source for determining a Monthly $SO_2$ Allowance Cost. At least one emission allowance exchange currently is operating with distribution lists reaching over 300 potential emission allowance traders. By bringing together many buyers and sellers, the exchange is able to truly approximate the actual replacement cost of an allowance. Because an exchange compiles many bids at once, no buyer in the market pays more than the market will bear. The opportunity to trade emission allowances instantly, and anonymously, through an exchange is less costly than orchestrating **a** sophisticated trade through bilateral negotiation. Further, by providing instant access to a market, the exchange is able to eliminate inter-temporal subsidies among consumers by promoting transactions that occur closest to the time of actual need. Replacement cost can be applied to allowances by reference to the prices for emission allowances listed on a market index, such as the Cantor Fitzgerald Environmental Brokage Services (EBS™) computerized trading screens which show binding bids and offers, not mere indications.

Cantor Fitzgerald is the most established market maker in this area. Established in 1945, Cantor Fitzgerald is the world's largest fixed income screen broker of U.S. government securities. With over 1300 employees in 16 offices world-wide, Cantor Fitzgerald transacts more than $7 trillion worth of financial assets annually. Cantor Fitzgerald EBS™ is recognized by most a5 the leading national source of information on current $SO_2$ allowance market clearing prices. Southern Companies believe that the electronic brokerage service that Cantor Fitzgerald has developed to trade emission allowances is the product of its extensive experience and technological expertise in the brokerage industry. Cantor Fitzgerald does not buy or sell emission allowances for its own account nor does it have any interest in any associated markets. The company's only role is to provide a conflict free intermediary to help effectuate emission allowance trading.

Thus, the Southern Companies propose to develop a purchase cost based on offers to sell emission allowances available for immediate settlement as quoted by Cantor Fitzgerald EBS™ on the 5th working day prior to beginning of the month in which the emission allowance cost will be applicable. The offers will be ranked from lowest per allowance price to the highest per emission allowance price. If the lowest priced offer does not have sufficient volume to supply the 2500 test emission allowance block, the unsatisfied quantity will be served from the second lowest priced offer. Each succeeding offer will be used until the entire **2500** test allowance block is costed. Consider the example given in Table A.

**Table A**: Monthly Allowance Cost: Calculations

| Price Per Allowance (Col. 1) | Volume of Allowances Available (Col. 2) | Test Quantity used by SCS for Monthly cost (Col. 3) | Purchase Cost of Test Quantity (Co. 4) | Average Monthly Cost Used for Allowance Pricing |
|---|---|---|---|---|
| | | | = col 1 x col 3 | = col 4/ col 3 |
| **$148.00** | **1,000** | **1,000** | **$148,000.00** | |
| **$152.SO** | **155** | **155** | $ **23,637.50** | |
| **$155.00** | **2,143** | **1,345** | $208,475.00 | |
| **$160.00** | **10,000** | **0** | $ - | |
| $180.00 | **550** | **0** | $ - | |
| | **TOTAL** | **2,500** | **$380,112.50** | **$152.05** |

current allowance volumes and offers for sale displayed in columns 1 and 2 of Table **A** for immediate settlement." Column 3 shows how, under a theoretical approach, replacement allowances from immediately available quantities of allowances (at fixed prices) would be used to meet satisfy a **2500** test block of allowances. Note that it takes several offers to make up the entire **2500** test block used in computing the monthly cost of emission allowances.

In other words, for purposes of determining the appropriate replacement cost of an allowance, the Southern Companies would assume that it could immediately purchase 1,000 allowances at **$148.00** per allowance, **155** allowances at the next highest offer of **$152.50** per allowance and 1,345 allowances at **S155.00**. By totaling the cost of purchasing all **2500** allowances and dividing that dollar figure ($380,112.50) by the test allowance quantity of **2,500**, the average allowance replacement cost for dispatch and pricing in September would be **$152.05**.

While there are pros and cons to any method of determining a single prevailing price for allowances, the Southern Companies

[15] The offers used here were available through Cantor Fitzgerald EBS™ **as** of September 1, **1994.**

believe that for the moment the approach outlined above has a number of attractive features:

- first, a monthly test procedure is frequent enough to account for changes in allowance values over time and infrequent enough to minimize the administrative burdens involved in a weekly or daily assessment;

- second, a monthly test is sufficient because the allowance market to date has not proven to be highly volatile on a weekly or daily basis;

- third, by using a fairly large test sample of allowances (2500) and a weighted averaging approach, the methodology eliminates the possibility that a tiny block of low-cost allowances will skew the replacement cost price for a potentially large number of transactions; and,

- fourth, reliance on Cantor Fitzgerald EBS™ will provide energy purchasers with a ready means of verifying the replacement cost calculation.

Again, the derived replacement cost would be used consistently for system dispatch and energy pricing under the IIC, for incremental energy cost under all non-associated coordination agreements, and for incremental energy pricing under the UPS agreements.

B. Provision of Allowances in Lieu of Replacement Cost Payment

As discussed, The Southern Companies also propose to allow affiliates, coordination sales customers and UPS customers alike the option of providing equivalent allowances instead of paying the replacement cost of allowances used in a particular energy transaction. Such an approach is possible because the Southern Companies have the capability to identify which units serve specific customers and, thus, the ability to determine the incremental $SO_2$ output of a particular unit operating for the benefit of a particular customer. The Southern Companies utilize an economic dispatch methodology for dispatching generation resources and for pricing off-system energy sales and energy transactions among the Southern Companies.

With respect to emission allowances as a production variable, all of the Southern Companies' FERC-jurisdictional agreements provide for bill payment by any mutually agreeable method. Since proper valuation of allowances ensures Southern Companies will be indifferent as between receiving payment in dollars or in equivalent: emission allowances, the Southern Companies intend to allow UPS and coordination Sales Customers, as well as each operating company under the IIC, to provide equivalent emission allowances in lieu of cash payments for emission allowances used under the agreements.

This alternative settlement procedure will function as follows: Before each month the Southern Companies will notify each customer of the Monthly SO, Allowance Cost that will be applied to emission allowances used during that month. Within five (5) days of receiving that notification, each customer will be required to make its binding selection of payment method for that month. If a customer elects to provide cash in payment for allowances used during that month, the customer shall make full payment in accordance with the billing procedures of the applicable agreement. If a customer chooses to provide allowances in lieu of cash for the portions of the charges reflecting emission allowance replacement cost, the customer shall settle its outstanding allowance balance at any time, but shall transfer allowances to the Southern Companies through the EPA SO, Allowance Tracking System ("ATS") no later than five (5) working days prior to January 20 of the year immediately following the year for which such emission allowances are required.[16] Once a payment method is selected for a given month, the customer is bound by that election for that month. This process will be repeated monthly.

The equivalent amount of emissions allowances for each service schedule or transaction type will be calculated as follows:

**.llowances Due =** $\dfrac{\text{Total Monthly Emission Allowance Replacement Cost ("TEC")}}{\text{Monthly SO, Allowance Cost ("AC")}}$

For administrative simplification, Southern Companies will round-off the amount of "Allowances Due" to the nearest whole number. The "Allowances Due" shall be the same vintage year as those used.'" The billing notice sent to a customer at the end of each

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[16] The cash balance due will be payable in accordance with the billing procedure of the applicable agreement.

[17] Southern Companies are required to have emission allowances resident in the unit-specific ATS accounts by January 30 of each year immediately following the year for which emission allowances are used. EPA requires five working days in order to effectuate a transfer of allowances between accounts. Under the organizational structure of the Southern Companies for purposes of transactions affected by this procedure, two levels of transfers must occur before the January 30 compliance deadline. First, Southern Company Services, Inc. must transfer allowances received from customers to the affected Operating Companies. Then, each Operating Company must place the allowances in the appropriate unit-specific ATS accounts. It is noted that failure to comply with the January 30 compliance deadline carries substantial penalty to Southern

month will include a calculation for the applicable billing period showing the amount of emission allowances utilized during the billing period, the corresponding Monthly $SO_2$ Allowance Cost.

Moreover, at the beginning of each year, customers will be asked to inform the Southern Companies whether they intend to the use the "in-kind" emission allowance settlement option in lieu of cash payment. Once a customer "default" is established, the Southern Companies will use the default information provided by customers for administrative purposes to assist in gauging the number of allowances it may be called upon to secure on its customer's account. The default chosen will not bind the customer to elect that option in any given month, but instead is provided for informational purposes only. It is noted, though, that once a customer makes its monthly election of payment options as detailed above, that election is binding.

## VIII. Conclusion

By providing its wholesale energy customers the option of paying either the replacement cost of emission allowances or of providing equivalent emission allowances to support a particular energy sale, the Southern Companies believe they are acting in conformance with Congressional intent in enacting the CAA Amendments. That intent is to encourage the development of a lightly regulated and active national market in emission allowances. The Southern Companies believe that both the FERC and state regulators will find this approach consistent with prudent and careful management of a new, yet valuable asset -- sulfur dioxide emission allowances.

At various times during the course of the legislative debate leading to passage of the CAA Amendments, Congress considered and rejected other approaches to cost-sharing in the form of broad based taxes and emissions fees to pay for the cost of reducing emissions under Title IV. Instead, the Congress devised the emission allowance trading system to reduce the cost impact of acid rain control. Congress concluded that the flexibility created by the emission allowance trading system could produce a nationwide cost-savings of fifty percent in Phase I of the program, fourteen percent to twenty percent when the program is first fully implemented at the beginning of Phase II and twenty percent cost-savings in 2010.

These savings were predicated on an economically competitive and dynamic emission allowance market in which cash revenues from the sale of emission allowances would create an incentive for

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Companies.

utilities to make cost-effective reduccions in sulfur dioxide emission allowances. To date, the experience of the Southern Companies confirms the wisdom of the approach that Congress took. Emission allowances are currently marketable, Phase I compliance costs are significantly lower than originally thought possible and Phase II compliance will be made easier because emission allowances are marketable.

To lessen cost impacts on native load customers (both retail and wholesale) the Southern Companies have devised a strategy in which native load customers will directly benefit from the availability of emission allowances. In other words, the compliance plan for the Southern Companies is based upon the use of the value of emission allowances as a proxy for determining the prudent and least-cost range of acceptable compliance expenditures. In turn, native load customers of each operating company will not bear the cost of using allowances initially allocated to their particular operating company by the EPA.

On the other hand, each set of customers within the Southern Company states will pay for the use of emission allowances that were initially allocated to another system operating company. This approach avoids the cross-subsidization of one state's consumers by another. In addition, each operating company will seek recompense for all emission allowances used to meet the energy demands of off-system wholesale arrangements, such as UPS and coordination-type sales. In this way, the Southern Companies will provide the correct environmental signal to off-system purchasers of power and will ensure that all incremental purchasers of power are treated equally.

Joe Connor
Vice President
Southern Wholesale Energy

Southern Company Services, Inc.
600 North 18th Street
P.O. Box 2625
Birmingham, Alabama 35202
Tel 205.257.5700
Fax 205.257.5703

SOUTHERN COMPANY
Energy to Serve Your World'

April 22, 1998

Mr. John Scardino
Florida Power Corporation
MAC - C2J
3201 34th Street South
St. Petersburg, FL 33711-3828

RE: Revision to 1988 UPS Agreement Cost of Capital Calculation

Dear Mr. Scardino:

Florida Power Corporation ("FPC") purchases capacity and energy from Alabama Power Company, Georgia, Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company (collectively referred to as the "Southern Companies") by and through their agent, Southern Company Services, Inc. ("SCS") under the Unit Power Sales Agreement dated July 19, 1988, which has been amended from time to time ("1988 UPS Agreement").

Section C2.2.19 of the manual to the 1988 UPS Agreement, "Adjustment to Cost of Capital Resulting From Retirement or Redemption of Outstanding Securities," was amended on September 13, 1996 with an effective date of November 1, 1994 (the "1996 Amendment"). This amendment documented our mutual agreement on the methodology for determining the proper adjustments for the cost of capital calculations under the 1988 UPS Agreement resulting from full and/or partial retirement or redemption of debt and preferred stock securities, and of full and/or partial retirement or redemption of securities that have been used to retire or redeem prior-issued securities (subsequent generation refundings).

Subsequent to the 1996 Amendment, the Southern Companies have issued a series of new securities. The securities are referred to as "Tax-Deductible Preferred Securities" and "Junior Subordinated Notes". These securities were not specifically addressed in the 1996 Amendment.

Tax-Deductible Preferred Securities are structured to allow the issuing company the ability to deduct (for federal income tax purposes) interest payments equal to the dividends paid to investors, while receiving equity credit from the rating agencies. The equity characteristics of this security, therefore, make it proper to be recognized as preferred stock. The "after tax" cost of Tax-Deductible Preferred Securities, accordingly, should be treated like Preferred Stock in *UPS* cost of capital calculations.

Mr. John Scardino
April **22,** 1998
Page Two

Junior Subordinated Notes are unsecured obligations of the issuing company, and are subordinate and junior in right of payment to the Senior Indebtedness of the company. This security exhibits characteristics of long-term debt and should be treated like a First Mortgage Bond in UPS cost of capital calculations.

The Southern Companies anticipate that these securities have been and will be used to redeem preferred stock and/or debt. The Southern Companies, on their own accord, recommend and agree that Tax-Deductible Preferred Securities and the Junior Subordinated Notes be recognized and treated in accordance with the methodology adopted in the amended UPS Agreement Cost of Capital calculations. The Southern Companies further recommend and agree that capacity refund adjustments will be calculated from January I, 1995, forward in order to recognize these securities.

This Letter Agreement shall be filed by SCS on behalf of the Southern Companies for review by FERC and shall be not be effective until FERC acceptance without material modification (as defined by the 1996 Amendment). Upon FERC acceptance, without material modification, this letter agreement shall become effective and the Southern Companies will credit charges under the UPS Agreement, as detailed above. Interest shall accrue on said sum in accordance with the UPS Agreement. FPC shall have the right to audit and confirm that the credits due to FPC are properly computed.

If you agree with the content of this letter, please indicate your agreement by signing below and returning this letter agreement to the undersigned.

Sincerely,

A. J. Connor

A. J. Connor, Vice President
Wholesale Market Planning and Services

ACCEPTED BY:

John Scardino

Florida Power Corporation

Dated: April 27, 1998

# THE SOUTHERN COMPANY

Operating Companies 2000 Actual and 2001 Projected SFAS No. 106 Costs

(Millions)

| Company | Actual 2000 | Projected 2001 |
|---|---|---|
| Alabama Power | $14.10 | $21.68 |
| Georgia Power | 538.59 | 544.43 |
| Gulf Power | 5 4.03 | 5 4.47 |
| Mississippi Power | $ 3.25 | 5 3.32 |
| Savannah Electric | $2.49 | $ 2.65 |

Note:

The Operating companies charge the annual FASB Statement No. 106 cost accrual to FERC Account 926, Employee pensions and benefits. The companies' formula rate contract billings include Account 926, net of amounts capitalized and allocated to various joint owners. Billings are based on budgeted data and reconciled during the year to actual data and also finalized at the end of each year, The 2000 actuarial studies for each company are attached.

Southem Operating Companies
Rate Schedule FERC No. 66

Original Sheet No. 122

W. L. Marshall, Jr.
Vice President
Fleet Operations and Trading
Southern Wholesale Energy

Southern Company Services, Inc
600 North 18th Street / GS 8256
Post Office Box 2611
Birmingham, Alabama 35291

Tel 205 257 6120
Fax 205 257 4652
wlmarsha@southernco.com

SOUTHERN COMPANY
*Energy to Serve Your World*™

December 2, 1999

Mr. John Scardino, Jr.
Vice President and Controller
Florida Power Corporation
P. O. Box 14042
St. Petersburg, Florida 33733-4042

RE: Fuel Accounting Procedures at Plant Miller

Dear Mr. Scardino:

Florida Power Corporation ("FPC") purchases capacity and energy from Alabama Powcr Company, Gcoryia Powcr Company, Gulf Powcr Company, Mississippi Power Company, and Savannah Electric and Power Company (collectively referred to as the "Southem Companies") hy and through their agent, Southem Company Services, Inc. ("SCS") under tlic Unit Power Sales Agreement dated July 19, 1988, which has been amended from time to time ("1988 UPS Agreement").

On July 10, 1995 FPC and Southern Companies entered into a Letter Agreement that revised certain fuel accounting procedures at Plant hliller effective January 1,1995. In an effort to reduce plant fuel costs, Alabama Powcr Company ("APCo") decided lo burn sub-bituminous coal in Plant Miller's Unit 4. The July 10, 1995, Letter Agreement tcviscd the fuel accounting proccdurcs applicable to the 1988 UPS Agreement by allocating the benefits and costs of tlic lower cost sub-bituminous coal equally across all units at Plant Miller. hlillcr Units 1, 2 and 3 continued *to* burn bituminous coal. Under the rcviscd proccdurcs, fuel at Plant Miller has been accounted for on a **BTU** basis, instead of on a tonnage basis, and a generation equivalent BTU factor is applied lo sub-bituminous coal lo reflect differences in thermal efficiency between bituminous and sub-bituminous coal. This approach was necessary to ensure FERC Accounting of the costs *of* two different types of coal. each of which had different heat value per ton.

As contemplated in the July 10, 1995, Letter Agreement ***APCo*** has taken further advantage of sub-bituminous coal and converted Plant Miller Unit 3 lo sub-bituminous coal in 1998 and convened Plant Miller Units 1 and 2 lo sub-bituminous coal during 1999. Currently all four units at Plant Miller are **burning** sub-bituminous coal.

Issued by: William L. Marshall, Jr., Vice President
Issued *on:* March 22, 2001

Effective Date: June 1, 2000

Mr. Scardino
December 2, 1999
Page 2

In an effort to streamline the fuel accounting process at APCo. and in recognition of the fact that all units at Plant Miller now burn the same type of coal. FPC and Southern Companies agree to suspend the revised "BTU" fuel accounting procedures described in the July 10, 1995 Letter Agreement, and revert to the fuel accounting process described in Article IV, Derivation of Fuel Costs and Normalized Fuel Costs for Electric Generating Units, of the 1988 UPS Agreement effective January 1, 2000. There should be no impact in billings as a result of this change in accounting procedures for sub-bituminous coal at Plant Miller.

FPC and Southern Companies further agree that if at some time in the future it becomes necessary that APCo burns both bituminous and sub-bituminous coal at Plant Miller, the accounting procedures set forth in the July 10, 1995 Letter Agreement would again apply in an analogous fashion. Southern Companies will provide notification to FPC if this change should occur.

This Letter Agreement will be filed by SCS on behalf of the Southern Companies for review by FERC and shall be not be effective until FERC acceptance without material modification (as defined by the 1995 Amendment).

If you agree with the content of this letter, please indicate your acceptance by signing below and returning this letter agreement to me, the undersigned Southern Company Services, Inc. representative.

Sincerely,

W. L. Marshall, Jr., Vice President
Southern Company Services, Inc.

ACCEPTED BY:

John Scardino, Jr.
Vice President and Controller
Florida Power Corporation

Dated: 3/10/00

Southern Operating Companies
Rate Schedule **FERC** No. 66

Original Sheet No. 150

W. L. Marshall, Jr.
Vice President
Fleet Operations a d Trading
Southern Wholesale Energy

Southern Company *Services*. Inc.
600 North 18th Street / GS-8259
Post Office Box 2641
Birmingham, Alabama 35291

Tel 205.257.6139

Fax 205.257.6652 [illegible]southernco com

SOUTHERN COMPANY
*Energy to Serve Your World*'

December 2,1999

Mr. **John** Scardino. Jr.
Vice President and Controller
Florida Power Corporation
P. O. **Box 14042**
St. Petersburg, Florida 33733-4042

RE: Revision to 1988 **UPS** Agreement Materials and Operating Supplies **(M&S)**

Dear **Mr.** Scardino:

Florida Power Corporation ("FPC") purchases capacity and energy from Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company. and Savannah Electric and Power Company (collectively referred to as the "Southern Companies") by and through their agent, **Southern** Company Services, Inc. ("SCS") under the Unit Power Sales Agreement dated July 19, 1988, which has been amended from time to time ("1988 UPS Agreement").

**Prior** to 1983, Alabama Power company ("APCo") recorded materials and operating supplies **("M&S")** in FERC Account **154, as** purchased. A ruling by the Internal Revenue Service of the United States Department of **Treasury** in 1983 disallowed for lax purposes **the** taking of expense deductions for the cost ***of*** M&S items when they are purchased. and required expenses to be recognized **when** such items are issued from inventory. ***APCo*** agreed (retroactively) not to include the **cost** of pre-1983 M&S items in FERC Account 154, Plant Materials and Operating Supplies, and therefore exclude the pre-1983 M&S items from the FPC billings beginning in **January** 1994.

Recently, ***APCo*** installed a new inventory Accounting, Materials and Purchasing System ("AMPS"). The installation of ***AMPS*** resulted in the pre-1983 M&S items being included in the Plant Miller inventory. In **March** 1999. APCo debited the inventory account, FERC Account **154**, with the value of the pre-1983 M&S items. During 1999, APCo will credit FPC the value ***of*** the pre-1983 **M&S** items by recording these items **as a** credit to FERC Account ***506,*** Miscellaneous Steam Power Expense. **As** a result, **FPC** would receive **a** credit for the pre-1983 inventory during 1999. but **as** issues from Miller's inventory ***occur,*** in the future, the credit will be offset incrementally **as** the pre-1983 M&S is issued from inventory and charged to the applicable FERC **Accounts.** Also, the

Southern Operating Companies
Rate Schedule FERC No. 66

Original Sheet No. 151

Mr. Scardino
December 2, 1999
Page 2

This Letter Agreement will be filed by SCS on behalf of the Southern Companies for review by FERC and shall be not be effective until FERC acceptance without material modification (as defined by the 1995 Amendment). Upon FERC acceptance without material modification this Letter Agreement shall become effective and the Southern Companies will credit charges under the UPS Agreement, as detailed above. Interest shall accrue on said sum in accordance with the UPS Agreement. FPC shall have the right to audit and confirm that the credits due to FPC are properly computed.

If you agree with the content of this letter, please indicate your acceptance by signing below and returning this letter agreement to me, the undersigned Southern Company Services, Inc. representative.

Sincerely,

W L Marshall Jr

W. L. Marshall, Jr., Vice President
Southern Company Services, Inc.

ACCEPTED BY:

Mr. John Scardino, Jr.
Vice President and Controller
Florida Power Corporation

Dated: 10/31/00

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southern Company Services, Inc. Docket No. ER00-325-001

## NOTICE OF FILING

(February 7,2001)

Take notice that on February 1,2001, Southern Company Services, lnc. (SCS), by and on behalf of Alabama Power Company, Georgia Power Company, Mississippi Power Company, Gulf Power Company and Savannah Electric and Power Company, tendered for filing amendments to unit power sales agreements with Florida Power and Light Company, Florida Power Corporation and Jacksonville Electric Authority, respectfully. The purpose of the amendments is to include the cost of sulfur dioxide emission allowances in the rates for Base and Normalized Energy under the unit sales agreements between SCS and each of the identified customers.

Any person desiring to be heard or to protest such filing should file a motion to intervene or protest with the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C.20426, in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). All such motions and protests should be filed on or before February 22, 2001. Protests will be considered by the Commission to determine the appropriate action to be taken, but will not serve to make Protestants parties to the proceedings. Any person wishing to become a party must file a motion to intervene. Copies of this filing are on file with the Commission and are available for public inspection. This filing may also be viewed on the Internet at http://www.ferc.fed.us/online/rims.htm (call 202-208-2222 for assistance). Comments and protests may be filed electronically via the internet in lieu of paper. See, 18 CFR 385.2001(a)(1)(iii) and the instructions on the Commission's web site at http://www.ferc.fed.us/efi/doorbell.htm.

David P. Boergers
Secretary

0110209 6175-1

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FEB 14 2001

BALCH & BINGHAM LLP

ATTORNEYS AND COUNSELORS
POST OFFICE BOX 306
BIRMINGHAM. ALABAMA 35201-0306
(205) 251-8100

ORIGINAL

WRITER'S OFFICE.
1710 SIXTH AVENUE NORTH
BIRMINGHAM. ALABAMA 35203-2015
FACSIMILE (205) 226-8798

DIRECT DIAL TELEPHONE.

February 1, 2001

Mr. David P. Boergers, Secretary
Docket Room
Office of the Secretary, Room 1A
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. **20426**

***Re:*** ***Southern Company Services, Inc.***
***Docket No. ER00-325-001***
***Substitute Filing of Consensus Amendments***

Dear Mr. Boergers:

**On** October 29, 1999, Southern Company Services, Inc., by and on behalf of Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company **and** Savannah Electric and Power Company (collectively, "Southern Company") tendered for filing under Section 205 of the Federal Power Act **a series** of unilateral amendments to certain unit power sale agreements between Southern Company and Florida Power & Light Company ("FPL"), Florida Power Corporation ("FPC") and Jacksonville Electric Authority ("JEA"), respectively (.collectively, the "*UPS* Agreements"). The purpose of the filing was to amend the rates for Base Energy and Normalized Energy contained in the UPS Agreements to address recovery of new energy-related costs to be incurred by Southern Company starting January 1, 2000. These costs relate to the expenditure of emission allowances in connection with scheduled generation from designated coal-fired units to ensure compliance with the Phase II sulfur dioxide emissions limitations of the Clean Air Act Amendment of 1990 ("CAAA").

On November 3, 1999, the Commission issued public notice of Southern Company's filing, inviting persons desiring to be heard or protest the filing to file on or before November 18, 1999. On November 18, 1999, FPL filed a motion to intervene and FPC filed a motion to intervene and protest. Under the Federal Power Act, the Commission had 60 days from the date of filing to review the application and *to* act initially. See 16 **U.S.C** § 824d. Under this requirement, the Commission was initially required to act on Southern Company's filing no later than December 28, 1999, or the filing is deemed accepted. In response to the issues raised and the concerns expressed by FPL and

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FPC, however, Southern Company, these two customers, and JEA (the only other purchaser of unit power from Southern Company under a UPS Agreement) commenced discussions in an attempt to amicably settle and resolve the differences that had arisen between the parties. On December 22, 1999, so that the parties adequately may explore potential settlement and to avoid unnecessary proceedings, Southern Company first requested that the Commission extend the date by which it must act. Southern Company continued that request periodically throughout the year 2000.

We are pleased to report that these discussions have produced agreement between Southern Company and the affected customers, which agreement is reflected in bilateral contract agreements between Southern Company and each of its three unit power sales customers: FPL, FPC and JEA. These bilateral contract agreements parallel closely the unilateral amendments originally tendered by Southern Company on October 29,2000, but contain several clarifications and revisions sought by the customers. In accordance with the Commission's regulations, six (6) copies of this letter, its enclosures, and form of notice (hard copy and electronic) are enclosed herewith for filing.

**Description Of and Reason for the Filing**

Base Energy and Normalized Energy under the UPS Agreements are based on the costs of generation at the base units. The base units are affected under Phase II of the CAAA. As such, it has become necessary to amend the Base Energy and Normalized Energy rate schedules to address emission allowance costs. Under the enclosed bilateral amendments, each UPS customer would be entitled to a pro rata share of emission allowances allocated to each base unit based upon its respective capacity entitlement share of each such unit. The customer would have an annual option, which must be exercised in writing by the end of each year, to: (i) take possession and ownership of its proportional share of emission allowances ("transfer option"); or (ii) have Southern Company retain possession of its proportional share of emission allowances and hold such allowances in a segregated account for the benefit of the customer ("banking option"). Under either the transfer option or the banking option, by the last business day of January for each following year, Southern Company would send the customer a statement detailing the amount of emission allowances payable in connection with the prior years' generation of base unit energy ("year end statement"). The customer would then transfer to Southern Company the specified amount of emission allowances.

Southern Company has also entered into letter agreements with each of the UPS customers to clarify that the above-described amendments have been entered into solely to include the cost of emission allowances in the rates for Base and Normalized Energy under the UPS Agreements and to establish procedures related to that process, and for no other purpose. These letters are also enclosed as part of this filing.

**Reauested** Waiver **Of Filing** Reauirements

These amendments are submitted under the abbreviated filing requirements of Section 35.13(a)(2)(i)(D). The infomation required by Section 35.12(b)(2) and *(5)* and Section 35.13(b), (c) **and** (h)(37) is enclosed to the extent that such information **is** relevant and available. To the extent the enclosed materials and information does not meet the detailed requirements of the foregoing regulations, it **is** respectfully requested that the Commission grant a waiver. Further, to the extent that **Commission** Order No. **614** applies to this filing, waiver **is** requested. Good cause exists for such waiver, if necessary, because Southern Company presently are developing revised UPS rate schedule sheets that will revise the format **of** the existing agreements to comply with the requirements of Order No. 614, and will submit those rate schedules in compliance with Commission staff requests in Southern Company's Docket No. ER01-602.

Requested **Effective Date**

**As** reflected in the tendered amendments, Southem Company, FPL, **FPC** and JEA have agreed, and Southern Company **now** requests, that all amendments filed herewith be permitted to become effective **as** of **January** 1,2000.

Documents **Submitted with this Filing**

The following **is a list** of the documents submitted with this filing:

(a) **Amendments** to the following agreements and contracts:

UPS Agreement with Florida Power Corporation (1988) (SCS Rate Schedule No. 66);

UPS Agreement with Florida Power & Light Company (1988) (SCS Rate Schedule No. **67);**

UPS Agreement with Jacksonville Electric Authority **(1** 988) (SCS Rate Schedule No. 68);

(b) **A** form of notice suitable for publication in **the** Federal Register, **as** required by Section **35.8** of the Commission's regulations.

(c) Supporting materials showing the effects of the proposed amendments.

**Miscellaneous**

**Authority** for the filing by **SCS of** the enclosed amendments **and** the related Certificate of Concurrence on behalf of the **Southern** Companies (except **Savannah** Electric and **Power Company)** is evidenced by letter dated **December 27, 1963** fiom the **Secretary** of the Federal Power commission to each of them. The **authority** for SCS to file on behalf of **Savannah** Electric **and** Power Company **was acknowledged** by Commission **order** dated June **16,** 1988, in Docket No. ER88-366-000.

Should additional information **be** required, it is requested that the undersigned attorney be contacted at the earliest possible date so that such information can be supplied expeditiously.

Respectfully yours,

Lyle D. Larson
One of the **Attorneys**
for Southern **Company**

cc: Service List

478846.2

# Amendments to
# UPS Agreement with Florida Power Corporation
# (SCS Rate Schedule No. 66)

$$(d) = ((a) + (b) + (c)) \left[ \frac{\%L_e \div 100}{1 - (\%L_e \div 100)} \right]$$

In addition to the foregoing items, there shall be $SO_2$ and NO, emissions allowance components, as determined pursuant to Section 6.3.1.

6.3.1 The $SO_2$ and NO, emissions allowance component shall be determined by one of the following methodologies, as appropriate:

(a) For purposes of determining the Alternate Energy Rate (Section 6.4), the Supplemental Energy Rate (Section 6.5), the Station Service Charges (Section 6.7) and the Discretionary Energy Rate (Section 6.8), the emission allowance component reflected in the Base Energy Rate will be the SO2 and NO, emission allowance replacement costs used by Southern Companies for internal purposes in the month in which $SO_2$ and NO, emission allowance costs are calculated, as adjusted for lossc s.

(b) For Unit Energy. this component is determined in accordance with the Unit Energy – $SO_2$ Emission Allowance Procedure (as to $SO_2$) and the Unit Energy – NO, Emission Allowance Procedure (as to NO,). as adjusted for losses.

6.4 <u>Alternate Energy Rates</u>: For energy supplied to Corporation at any time from alternate sources owned or operated by Southern Companies, in accordance with Section 3.7. Corporation shall pay an amount per MWH delivered which is the least of (i) the Base Energy Rate as determined in Section 6.3 for the unit for which Alternate Energy is provided; (ii) the Normalized Energy Rate as determined in Section 6.6 for the unit for which Alternate Energy is provided; or (iii) one-half (0.5) the sum of the Base Energy Rate for such unit and the cost of such Alternate Energy determined by the following principles:

For alternate Energy whether supplied from **an** assigned unit of Southern Companies, or from the units in economic dispatch on the systems of Southern Companies, the cost of such energy ($/MWH) shall be the incremental expense of the assigned unit of the units in economic dispatch, such energy shall be considered as having been delivered at the incremental cost of Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery of such energy. The only power sale commitments taking precedence before delivery of such Alternate Energy are: (i) any seasonal energy or capacity exchange agreements now existing or entered into in the future; and (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future. The expense from assigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, emission allowance replacement costs, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

*6.5* <u>Supplemental Energy Rates</u>: For energy supplied to Corporation at any time pursuant to Section 3.8, Corporation shall pay **an** amount per MWH delivered which is the greater of the (i) Base Energy Rate for the unit for which Supplemental Energy is provided, as determined in Section 6.3; provided, however, such Base Energy Rate shall be limited to a value no greater than the Normalized Energy Rate as determined in Section 6.6 for such unit; or (ii) the increment cost of the units in economic dispatch incurred by Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery of such Supplemental Energy as defined in Section 3.8.5. The expense from assigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, emission allowance replacement costs, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

6.6 Normalized Energy Rates: The Normalized Energy Rate each month for each unit specified in Exhibit A shall be equal to the sum of the following items (expressed in \$/MWh):

(a) Normalized Fuel cost for the unit, which is defined in Article IV of the Unit Power Sale Manual.

(b) The variable operation and maintenance expenses for the unit as described in Article V of the Unit Power Sale Manual.

(c) The in-plant fuel handling expenses for the unit as described in Article V of the Unit Power Sale Manual.

(d) Compensation for transmission losses, based on the average transmission loss percentage ($\%L_e$) set forth in Article VII of the Unit Power Sale Manual. Using (a), (b) and (c) above:

$$(d) = ((a) + (b) + (c)) \quad \left[\frac{\%L_e \div 100}{1 - (\%L_e \div 100)}\right]$$

(e) An $SO_2$ and a $NO_x$ emissions allowance component, as determermned pursuant to Section 6.3.1(a).

6.7 Station Service Charges: For station service energy required each month for a unit specified in Exhibit **A** during the hours in which the net electrical output of such unit is equal to or less than zero, Corporation shall pay an amount per MWH, for a pro rata share of such station service energy based on the ratio of Corporation's capacity entitlement in such unit pursuant to Article II to the Net Dependable Capacity of such unit, equal to the Base Energy Rate of such unit as deternuned in Section 6.3; provided,

$$(d) = ((a) + (b) + (c)) \quad \left[ \frac{\%L_e \div 100}{1 - (\%L_e \div 100)} \right]$$

In addition to the foregoing items, there shall be $SO_2$ and $NO_x$ emissions allowance components, as determined pursuant to Section 6.3.1.

6.3.1 The $SO_2$ and $NO_x$ emissions allowance component shall be determined by one of the following methodologies, as appropriate:

(a) For purposes of determining the Alternate Energy Rate (Section 6.4), the Supplemental Energy Rate (Section 6.5), the Station Service Charges (Section 6.7) and the Discretionary, Energy Rate (Section 6.8), the ~~$SO_2$ emissions~~ allowance component reflected in the Base Energy Rate will be the $SO_2$ and $NO_x$ emission allowance replacement costs –used by Southern Companies for internal purposes in the month in which $SO_2$ and $NO_x$ emission allowance costs ~~is~~are calculated, as adjusted for losses.

(b) For Unit Energy, this component is determined in accordance with the Unit Energy – $SO_2$ Emission Allowance Procedure (as to $SO_2$) and the Unit Energy – $NO_x$ Emission Allowance Procedure (as to $NO_x$), as adjusted for losses.

6.4 Alternate Energy Rates: For energy supplied to Corporation at any time from alternate sources owned or operated by Southern Companies, in accordance with Section 3.7, Corporation shall pay an amount per MWH delivered which is the least of (i) the Base Energy Rate as determined in Section 6.3 for the unit for which Alternate Energy is provided; (ii) the Normalized Energy Rate as determined in Section 6.6 for the unit for which Alternate Energy is provided; or (iii) one-half (0.5) the sum of the Base Energy Rate for such unit and the cost of such Alternate Energy determined by the following principles:

For alternate Energy whether supplied from an assigned unit of Southern Companies, or from the units in economic dispatch on the systems of Southern Companies, the cost of such energy ($/MWH) shall be the incremental expense of the assigned unit of the units in economic dispatch, such energy shall be considered as having been delivered at the incremental cost of Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery of such energy. The only power sale commitments taking precedence before delivery of such Alternate Energy are: (i) any seasonal energy or capacity exchange agreements now existing or entered into in the future; and (ii) any firm power interchange sales to other utilities or third parties now existing or entered into in the future. The expense from assigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and maintenance expenses, emission allowance replacement costs, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

*6.5* Supplemental Energy Rates: For energy supplied *to* Corporation at any time pursuant to Section 3.8, Corporation shall pay an amount per MWH delivered which is the greater of the (i) Base Energy Rate for the unit for which Supplemental Energy is provided, as determined in Section 6.3; provided, however, such Base Energy Rate shall be limited to **a** value no greater than the Normalized Energy Rate as determined in Section 6.6 for such unit; or (ii) the increment cost of the units in economic dispatch incurred by Southern Companies after serving their own systems' requirements (including energy used for pumping at pumped storage hydroelectric projects) and other power sale commitments taking precedence before delivery of such Supplemental Energy as defined in Section 3.8.5. The expense froni assigned units or units in economic dispatch shall include only the incremental cost of fuel, variable operation and niaintenance expenses, emission allowance replacement costs, change in system transmission losses, and other such energy related costs which would otherwise not have been incurred.

6.6 Normalized Energy Rates: The Normalized Energy Rate each month for each unit specified in Exhibit **A** shall be equal to the sum of the following items (expressed in \$/MWh):

(a) Normalized Fuel cost for the unit, which is defined in Article IV of the Unit Power Sals Manual.

(b) The variable operation and maintenance expenses for the unit as described in Article V of the Unit Power Sale Manual.

(c) The in-plant fuel handling expenses for the unit as described in Article V of the Unit Power Sale Manual.

(d) Compensation for transmission losses, based on the average transmission loss percentage ($\%L_e$) set forth in Article VII of the Unit Power Sale Manual. Using (a). (h) and (c) above:

$$(d) = ((a) + (b) + (c)) \left[ \frac{\%L_e \div 100}{1 - (\%L_e \div 100)} \right]$$

(e) An $SO_2$ and a NO, emissions allowance component, as determined pursuant to Section 6.3.1(a).

6.7 Station Service Charges: For station service energy required each month for **a** unit specified in Exhibit A during the hours in which the net electrical output of such unit is equal to or less than zero, Corporation shall pay **an** amount per MWH, for **a** pro rata share of such station service energy based on the ratio of Corporation's capacity entitlement in such unit pursuant to Article II *to* the Net Dependable Capacity of such unit, equal to the Base Energy Rate of such unit as determined in Section 6.3; provided,

## UNIT ENERGY- NOx EMISSION ALLOWA ICE PROCEDURE

**Applicability:** This procedure shall apply to the allocation of and the in-kind or cash payment for nitrogen oxides ("$NO_x$") emission allowances ("Allowances") under Section 6.3 of the Unit Power Sales Agreement between Florida Power Corporation ("FPC") and Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company and Savannah Electric and Power Company (collectively, "Southern") dated July 19, 1988, as amended ("1988 UPS Agreement").

Procedure: Allocation - Each year that Unit Energy is to be made available to FPC by Southern under the 1988 UPS Agreement, and for each unit contractually specified to generate such Unit Energy ("base unit(s)"), Southern shall allocate to FPC a pro rata share of Allowances allocated to Southern for each base unit pursuant to the multi-state NO, air pollution control and emissions reduction program established by the United States Environmental Protection Agency ("EPA") pursuant to regulations promulgated under the Clean Air Act. FPC's pro rata share will be based upon FPC's contracted percentage share of capacity at each base unit for the year of allocation. That percentage share will then be multiplied by the Allowances allocated to Southern for each base unit for that year *to* determine the number of Allowances allocated FPC. Nothing herein shall prohibit FPC from entering into an agreement with Southern, in combination or individually, to sell any or all Allowances allocated to FPC hereunder.

Allocation Options - FPC will have an annual option, which must be exercised by the first business day of the month immediately preceding the Ozone Season of each year, to: (i) take possession and ownership of its proportional share of Allowances (hereafter referred to as the "transfer option"); or (ii) have Southern retain possession of such Allowances and hold them in a segregated general EPA NO, Allowance Transfer System ("NATS") account for FPC's benefit (hereafter referred to as the "banking option"). In the event FPC does not select the transfer option on a timely basis, the banking option will be deemed selected for the applicable Ozone Season. FPC also may establish a standing designation under which FPC shall be deemed to have exercised said election by the date(s) specified above. If FPC designates the transfer option for a given Ozone Season, then by the tenth ($10^{th}$) business day of the first month of the Ozone Season, Southern will transfer FPC's Allowance allocation into an FPC designated EPA NATS account. Should FPC designate the banking option for an Ozone Season, then by the last business day of the first month of the Ozone Season, FPC's Allowance allocation will be placed by Southern into a non-investment general EPA NATS account established for the purpose of holding FPC's banked Allowances. Representatives of Southern will be the authorized account representative ("AAR") and alternative account representative for this account.

Calculation of Allowances Consumed - The procedure for determining the amount of Allowances used to generate Base Energy under the 1988 UPS Agreement (and thus the amount of any deficit Allowances that must be provided to Southern) will be as follows:

Monthly Estimate - The total base unit emission quantity will be estimated monthly (within the annual Ozone Season) based on a calculation of the total monthly MWHs of Base Energy taken multiplied by a monthly $NO_x$ emissions per MWH rate. This monthly $NO_x$ emissions rate will reflect the continuous emissions monitoring system ("CEMS") data most recently available for the applicable unit. Southern will provide to FPC a monthly estimate not later than the twentieth (20th) business day of the successive month of the Ozone Season.

Ozone Season Reconciliation Report - No later than the tenth (10th) business day of the month following the Ozone Season, Southern will submit to FPC a final report showing the total number of Allowances associated with FPC's Base Energy usage during the Ozone Season and the total number of deficit or excess Allowances after application of any Allowances banked for the benefit of FPC against the Allowances required for FPC's use of Base Energy. If a deficit is identified, then the Settlement Procedures immediately set forth below shall govern.

Settlement Procedures for Deficit Allowance Balance - By the fifteenth (15th) business day of the month immediately following the Ozone Season (the "Settlement Period"), FPC will notify Southern of its intention to pay in-kind, in cash, or some combination thereof. Southern will thereafter provide to FPC a written accounting that details the number of Allowances payable to Southern as well as the cash amount owed (if applicable).

In-Kind - If in-kind payment is indicated, then by the twentieth (20th) business day of the month immediately following the close of the Ozone Season, FPC will transfer to Southern the amount of Allowances of appropriate vintage determined by Southern to be payable in connection with the Base Energy taken by FPC during the Ozone Season.

Cash - If cash payment has been indicated, then the Reconciliation Report will also indicate a cash equivalent dollar amount due Southern for the number of deficit Allowances. The cash equivalent dollar amount due shall be the product of *the* Market Proxy Price times the number of deficit Allowances. The Market Proxy Price shall be the average price of the most current bid and offer prices for the tenth ($10^{th}$) business day of the Settlement Period for the Allowances for that vintage year **as** published in the Evolution Express Market Price Report created daily by Evolution Markets LLC, **(as** it may be replaced as necessary or convenient, by a similar report that is agreed to by both parties) together with all transaction costs (as detailed below) associated with the purchase of such Allowances. FPC will wire transfer this dollar equivalent amount into an account so designated by Southern by the twentieth ($20^{th}$) business day of the Settlement Period.

Excess Allowances - If, after full settlement of any deficit Allowance balance due in a Settlement Period, there are remaining Allowances in the banking account, then the AAR or alternate AAR will, at the direction of FPC, either: (i) document the number of excess Allowances remaining in the EPA ATS account and earmark these for FPC's future use in connection with Base Energy; (ii) transfer such remaining Allowances into other EPA NATS account(s) specified by FPC; or (iii) transfer such remaining Allowances to Southern. The parties may agree in advance that FPC shall transfer remaining allowances io Southern, under terms **and** conditions separately negotiated between the parties.

Remedv: FPC has assumed the responsibility to deliver to Southern all Allowances (or their cash equivalent) to satisfy any deficit Allowance balance identified by Southern in the Ozone Season Reconciliation Report described above. To the extent Southern fails to receive such Allowances (or their cash equivalent) from FPC by the appointed date, then Southern shall obtain the deficient quantity of Allowances from external and/or internal sources (at their discretion). With respect to external sources, Southern may purchase such Allowances by any commercially reasonable means available to them. In that event, Southern will invoice FPC and FPC shall promptly pay Southern the sum of the following: (i) the cost of purchasing a sufficient quantity of Allowances to cover the deficiency; and (ii) transaction costs (including, without limitation, commissions, legal fees, administrative expenses incurred in connection with the transaction) and any other expense that would not otherwise have been incurred. If Southern is unable to secure the necessary deficient Allowances in the open market or otherwise chooses to rely on their internal sources of Allowances (if any) to cover the deficit amount, then Southern will calculate a then-current market price lor such Allowances and use it in item (i), above, and FPC agrees to promptly pay Soutlicrn the same together with any transaction costs and other expenses incurred by Southern in connection therewith In the event FPC fails in any two consecutive years to provide all required in-kind Allowances (or their cash equivalent), then Southern may require FPC *to* use the banking option for the remaining terms of the 1988 UPS Agreement.

Agreed to this 2nd day of February, 2004.

**Florida Power Corporation**

By: Robert F. Caldwell

Its: Vice President