Rate Schedule No. 97

INTERCONNECTION AGREEMENT
BETWEEN
DUKE ENERGY PROGRESS, LLC
AND
SOUTH CAROLINA ELECTRIC & GAS COMPANY

THIS INTERCONNECTION AGREEMENT (Agreement) is made and entered into this 28th day of March 2018, by and between DUKE ENERGY PROGRESS, LLC (DEP), a limited liability company organized and existing under the laws of the State of North Carolina, and SOUTH CAROLINA ELECTRIC & GAS COMPANY (SCE&G), a corporation organized and existing under the laws of the State of South Carolina.

W I T N E S S E T H:

WHEREAS, DEP and SCE&G first entered into an Interchange Agreement dated as of July 9, 1970 and have amended and restated such agreement multiple times since that date; and

WHEREAS, DEP and SCE&G desire to amend and restate such agreement as described herein, reflecting changes to FERC-jurisdictional facilities identified in this Agreement.

NOW THEREFORE, in consideration of the above premises and of the mutual benefits from the covenants set forth, DEP and SCE&G hereby agree as follows:

ARTICLE 1

PURPOSE

The purpose of this Agreement is to provide means for utilizing existing interconnections and future interconnections in order to coordinate the operation of the respective generation, transmission and substation facilities to the mutual advantage of both parties.

To fully realize these advantages, DEP and SCE&G mutually agree to appoint a committee of authorized representatives to be known as the "Operating Committee" and further agree to effectuate the service schedules referenced herein to govern the transactions between the two parties.

ARTICLE 2

DURATION

This Agreement shall become effective at 12:01 AM, June 1, 2018, and shall continue in effect for ten years, and thereafter it shall continue in force from year to year, provided, however, that the parties hereto, or either of them, can terminate this Agreement at the end of the original term of ten years, or at the end of any year thereafter, by giving at least three years' previous notice of such termination in writing.

This Agreement and any amendments thereto are contingent upon any approval required by Federal or State authorities.

ARTICLE 3

INTERCONNECTION POINT

Electric capacity and energy as is provided for hereunder shall be delivered and received at the existing interconnection points between the facilities of DEP and SCE&G or at any other mutually agreeable point or points confirmed in writing, such point or points to be designated and hereinafter referred to as "Interconnection Point".

ARTICLE 4

SERVICES TO BE RENDERED

The power to be supplied by each party to the other hereunder, the terms and conditions of such supply, and the settlement therefore shall be in accordance with arrangements agreed to from time to time between the parties. Such arrangements shall be set up in the form of Service Schedules. The following Service Schedule and Appendices are hereby agreed to and attached as part hereof:

Service Schedule A

Appendix A - Determination of Reserve Service Rates – SCE&G
Appendix B - Determination of Reserve Service Rates – DEP

ARTICLE 5

OPERATING COMMITTEE

An Operating Committee shall coordinate operations in carrying out the terms of this Agreement, and each of the parties hereto shall designate in writing to be delivered to the other party not later than thirty (30) days after the date hereof the person who is to act as its representative on said committee (and the person or persons who may serve as alternate whenever such representative is unable to act). Such representatives and alternate or alternates shall each be persons familiar with the generation, transmission and substation facilities of the system of such party by which they have been so designated, and each shall be fully authorized to collaborate with the other representative (or alternates) and from time to time as the need arises, subject to the declared intentions of the parties herein set forth, and to the terms hereof, and the terms of any other agreements pertaining hereto subsequently arrived at between the parties, to determine and agree upon all matters as outlined in service schedules under this Agreement.

ARTICLE 6

INTERCONNECTION POINTS AND FACILITIES

Existing Interconnection Points

All present interconnection facilities, including the metering equipment at three locations--the Eastover Substation, the St George Substation, and the Wateree Steam-Station, owned by SCE&G, and the transmission lines between the above stations and the Sumter Substation, owned by DEP, will be utilized in carrying out the provisions of the schedules under this Agreement.

For the purposes of this Agreement, the present interconnection points on the transmission lines described in the above paragraph are as follows:

1. **Eastover – Sumter 115 kV tie:** The Sumter - Eastover 115 kV transmission line at the first structure west of the Richland-Sumter County line in Richland County, South Carolina. Specifically, the conductor and shield wire on the east side of the structure as well as the associated connection hardware shall be the property of DEP; all other parts of the structure shall be the property of SCE&G.

2. **Wateree – Sumter 230 kV tie:** The Sumter - Wateree 230 kV transmission line at the first structure west of the Richland-Sumter County line in Richland County, South Carolina. Specifically, the conductor and shield wire on the east side of the structure as well as the associated connection hardware shall be the property of DEP; all other parts of the structure shall be the property of SCE&G.

3. **St George – Sumter 230 kV tie[1]:** The Sumter - St George 230 kV transmission line at the second structure southwest of the Orangeburg-Clarendon County line in Orangeburg County, South Carolina. Specifically, the conductor and shield wire on the east side of the structure as well as the associated connection hardware shall be the property of DEP; all other parts of the structure shall be the property of SCE&G.

[1] The St. George – Sumter 230kV Tie was previously known as the Canadys-Sumter tie. Electrically the interconnection facilities have not changed, but rather, the name Canadys is replaced with St. George due to implementation of a new SCE&G nomenclature standard.

Additional Interconnection Points

All new interconnection points between DEP and SCE&G which may be added in the future shall be included under this Agreement.

Elimination of Interconnection Points

If in the judgment of either party it appears desirable to discontinue any interconnection point covered in this article, the parties hereto shall consult with each other with respect thereto and may, by mutual agreement, discontinue such interconnection point.

Accessory Facilities

To facilitate the transactions contemplated under this Agreement, the parties will provide communication, telemetering, relaying, and load control equipment adequate for handling the power interchange contemplated under this Agreement; the extent and character of such equipment will be in accordance with good engineering practice. Unless otherwise agreed to, DEP at its expense, shall provide, own, operate, maintain, and replace such of the aforesaid equipment as will be used predominantly for DEP; and SCE&G, at its expense, shall provide, own, operate, maintain, and replace such of the aforesaid equipment as will be used predominantly for SCE&G.

Maintenance of Facilities

Each of the parties, at its expense, shall maintain in operable condition its facilities required for the effective use of the aforesaid interconnections for the purposes herein provided.

ARTICLE 7

SERVICE CONDITIONS

Operation of Systems in Parallel

The DEP system and the SCE&G system shall be and shall remain interconnected at the interconnection points described in Article 6 hereof, insofar as this can be done in the opinion of each party without jeopardy to its system or to service to its customers.

Control of System Disturbance

Each party shall exercise reasonable care to maintain and operate its system in accordance with good utility operating practice in such manner as to minimize the likelihood of disturbance originating in its system which might impair the service of the system of the other party or of any system interconnected with the system of the other party. In the event of any such disturbance, the cause of such disturbance shall be removed as soon as practicable. Neither party shall be responsible to the other party for any damage or loss of revenue caused by any such disturbance.

Continuity of Service

Each party shall exercise reasonable care to maintain continuity of service in the delivery and receipt of capacity and energy under this Agreement. If continuity of service becomes interrupted for any reason, the cause of such interruption shall be removed and normal operating conditions restored as soon as practicable. Neither party shall be responsible to the other party for any damage or loss of revenue caused by any such interruption.

Control of Kilovar Exchange

Neither party shall be obligated to deliver kilovars for the benefit of the other party. Neither party shall be obligated to receive kilovars when to do so might introduce objectionable operating conditions on its system. Subject to the foregoing, the Operating Committee shall establish from time to time (a) operating procedures for the carrying of kilovar loads in order to secure adequate service and economical use of the facilities of the parties and (b) proper charges, if any, for the carrying of such kilovar loads.

Control of Unscheduled Deliveries

The amounts of power being supplied hereunder by one party to the other under Service Schedule A shall be the amounts agreed upon by the parties' Operating Committee. The parties shall operate their respective systems in such a manner as to make the net deliveries of power and energy as nearly equal as practicable to the net scheduled deliveries. Any difference between net scheduled and actual net deliveries shall be accounted for according to established procedures for interconnected system operation as approved by the Operating Committee, and such differences shall be settled by appropriate compensatory deliveries in accordance with established utility practice.

Undue Burden

Each party shall operate its system so as not to place a burden on the system of the other party. If it should be found that one party is placing a burden upon the other, the party causing such burden shall take such measures as are necessary to remove the same or, at the election of the burdened party, the parties shall enter into such arrangements as shall provide for equitable compensation to the burdened party.

Special Studies of Maintenance and Operations

If at any time either party is not satisfied that the other party is maintaining and operating its system as required by this Article 7, it may, by notice to such party, call for a special study by the Operating Committee to determine what changes, if any, should be made to comply with the requirements of this Article.

Transmission Losses

The parties recognize that transactions between either party and a third party, not a party hereto, may result in an increase in transmission losses on the system of the other party hereto. When requested by either party, the parties hereto shall consider the factors involved, giving weight to the frequency and regularity of the indicated increases in such losses and the magnitudes of such increases, and will attempt to arrive at an equitable solution.

ARTICLE 8

RECORDS AND STATEMENTS

The parties shall keep such log sheets and other records as may be needed to afford a clear history of the various deliveries of electric energy made by one party to the other. The originals of log sheets and other records shall be retained by the party keeping the records, and copies shall be furnished to the other party as needed for carrying out transactions hereunder.

The Operating Committee shall establish, and from time to time amend and modify, if necessary, the power recording procedure requisite to the maintaining of clock-hour records needed to afford a clear history of the various deliveries made by one party to the other. The parties recognize that such procedures shall take into account appropriate adjustment for electrical losses of metered clock-hour integrated kilowatt demands and energy delivered by one party to the other. Electrical loss adjustment ratios and the conditions and methods governing the determination and the application of such ratios shall be determined and agreed upon by the Operating Committee.

ARTICLE 9

METER READING AND RECORDING EQUIPMENT

Authorized representatives of both parties shall have access at all reasonable hours to the recording equipment utilized for transactions under this Agreement and to all records necessary for computations under this Agreement.

Each party shall have the right to install, at its expense, check-metering equipment in suitable space provided without charge by the party owning the metering equipment. Should either party's meters fail to register for any period, the deliveries during such period shall be determined from the other party's meters or by the Operating Committee from the best information available.

Each party shall, at its own expense, make periodic tests and inspections of its metering equipment at intervals agreed upon by the Operating Committee to maintain a high standard of accuracy. If requested by either party, the other party shall make additional tests and inspections of its metering equipment; if such additional tests show that the measurements are accurate within one percent fast or slow, the cost of making such additional tests or inspections shall be paid by the party requesting such additional tests or inspections. Each party shall give the other party reasonable notice of tests so that it may have a representative present if it wishes.

If any tests or inspections under the above paragraph show either party's measurements to be inaccurate by more than one percent, the parties agree to correct erroneous deliveries of energy for any known or agreed periods of inaccuracy via “in-kind” payback as mutually agreed to. In the absence of such knowledge or agreement, the adjustment shall be limited to known inaccuracy for the current and prior month. Any metering equipment found to be inaccurate by more than one percent shall be promptly replaced, repaired, or readjusted by the party owning such defective metering equipment.

ARTICLE 10

BILLINGS AND PAYMENTS

All bills for amounts owed by one party to the other shall be due and payable fifteen (15) days following the calendar month or period service was rendered, or on the tenth day following receipt of bill, whichever date is later. Interest on unpaid amounts, both principal and interest, shall accrue daily at the then current prime interest rate per annum of CitiBank, plus two percent (2%) per annum, from the date due until the date upon which payment is made. Unless otherwise agreed upon, a calendar month shall be the standard monthly period for the purpose of settlements under this Agreement.

ARTICLE 11

NOTICES

All notices under this Agreement shall be in writing and shall be delivered in person or sent by mail addressed to the general office of the other party or to such other address as that party may have designated in writing.

ARTICLE 12

FORCE MAJEURE

Each party shall exercise due diligence and reasonable care to maintain continuity of service in the delivery and receipt of energy as provided for in this Agreement, but neither party shall be considered to be in default in respect to any obligation by reason of or through strike, stoppage in labor, failure of contractors, suppliers of material, riot, fire, flood, ice, invasion, civil war, commotion, insurrection, military or usurped power, order of any court or judge granted in any bona fide adverse legal proceedings or action, order of any civil authority, or military, either de facto or de jure, explosion, act of God, or the public enemies, or any cause reasonably beyond its control, and not attributable to its neglect.

ARTICLE 13

RESPONSIBILITY AND INDEMNIFICATION

Neither party hereto shall be responsible for injury or damage to any apparatus or property of the other and the one delivering power shall not be responsible for electric capacity and energy after delivery by it to the other at the point of delivery. Each party hereto expressly agrees 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 (the indemnifying party's) own side of the point of delivery hereunder; provided, however, that each party hereto, insofar as the other party hereto is concerned, shall in all cases be responsible for damage or injury to its own employees to the extent compensation benefits are payable therefor under any workers' compensation law, and each party expressly agrees to indemnify and save harmless the other from all claims of such employees to this extent.

ARTICLE 14

ARBITRATION

In the event of disagreement between the parties with respect to (1) any matter herein specifically made subject to arbitration, (2) any question of operating practice involved in the deliveries of power herein provided for, (3) any question of fact involved in the application of the provisions of this Agreement, or (4) the interpretation of any provision of this Agreement, the matter involved in the disagreement shall, upon demand of either party, be submitted to arbitration in the manner hereinafter provided. An offer of such submission to arbitration shall be a condition precedent to any right to institute proceedings at law or in equity concerning such matter.

The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the subject or subjects to be arbitrated, and the parties thereupon shall endeavor to agree upon and appoint one person to act as sole arbitrator. If the parties fail so to agree within a period of fifteen days from the receipt of the original notice, the party calling for the arbitration shall, by written notice to the other party, call for appointment of a board of arbitrators skilled with respect to matters of the character involved in the disagreement, naming one arbitrator in such notice. The other party shall, within ten days after the receipt of such call, appoint a second arbitrator, and the two so appointed shall choose and appoint a third. In case such other party fails to appoint an arbitrator within said ten days, or in case the two so appointed fail for ten days to agree upon and appoint a third, the party calling for the arbitration, upon five days' written notice delivered to the other party, shall apply to the person who at the time shall be the Senior Judge, in point of service, of the United States District Court for the District of South Carolina, for appointment of the second or third arbitrator, as the case may be.

The sole arbitrator, or the board of arbitrators, shall afford adequate opportunity to the parties to present information with respect to the question or questions submitted for arbitration and may request further information from either or both parties. The findings and award of the sole arbitrator or of a majority of the board of arbitrators shall be final and conclusive with respect to the question or questions submitted for arbitration and shall be binding upon the parties. Each party shall pay for the services and expenses of the arbitrator appointed by or for it, if there be a board of arbitrators, and all other costs incurred in connection with the arbitration shall be paid in equal parts by the parties hereto, unless the award shall specify a different division of the costs.

ARTICLE 15

ASSIGNMENT

Either party may assign this Agreement by way of pledge to a trustee under a mortgage securing its indebtedness or to a successor corporation acquiring its electric utility property and business substantially as an entirety, provided such successor corporation assumes all obligations of the assignor under this Agreement. Except as aforesaid, neither party shall assign this Agreement without the prior written consent of the other party.

ARTICLE 16

WAIVER

Any waiver at any time of any rights as to any default, or other matter arising hereunder, shall not be deemed a waiver as to any subsequent default or matter. Any delay, short of the statutory period of limitation, in asserting any right hereunder, shall not be deemed a waiver of such right.

ARTICLE 17

REGULATORY AUTHORITY

Nothing contained in this Agreement shall be construed as affecting in any way the right of either party under this Agreement or under any schedule annexed to and made part of this Agreement to unilaterally make application to the Federal Energy Regulatory Commission under Section 205 of the Federal Power Act, and pursuant to the Commission's Rules and Regulations, for a change either in the rates and charges for each of the several services to be rendered pursuant to this Agreement or to the schedule annexed to this Agreement.

IN WITNESS WHEROF, the parties have caused this Agreement to be executed by their duly authorized officers.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

By: P. Xanthakos

Name: Pandelis Xanthakos
Title: VP-Electric Transmission
Date: 3|21|18

REVIEWED BY LEGAL
3/21/18

DUKE ENERGY PROGRESS, LLC

By: V. Nelson Peeler

Name: Nelson Peeler
Title: SVP, chief Transmission Officer
Date: 3/28/2018

SERVICE SCHEDULE A

EMERGENCY RESERVE CAPACITY,
CONTINGENCY RESERVE CAPACITY, AND
DAILY RESERVE CAPACITY

SECTION 1 - DURATION

1.1 This Service Schedule shall continue in effect until termination or expiration of the Agreement unless superseded on any earlier date by a new service schedule or until terminated as provided for in Section 1.2 below.

1.2 Either party upon at least three years' prior written notice to the other party may terminate this schedule. In the event of such a termination, the parties agree to amend this Agreement to delete this schedule and to file such amended and restated agreement with the Federal Energy Regulatory Commission for acceptance for filing.

SECTION 2 - DEFINITIONS

2.1 Emergency Reserve Capacity is defined as the capacity provided during the first 12 hours (or the remainder of the calendar day, if greater than 12 hours) following the emergency loss of a resource. The period during which Emergency Reserve Capacity is supplied shall be defined as the Emergency Period.

2.2 Daily Reserve Capacity is defined as the capacity provided immediately following an Emergency Period, or capacity provided as a matter of efficiency, or as otherwise mutually agreed.

2.3 Contingency Reserve Capacity is defined as capacity that may be made available following the emergency loss of a resource.

SECTION 3 - SERVICES TO BE RENDERED

3.1 In the event of an emergency loss of a resource, each system will make available to the other, up to the total available Contingency Reserve Capacity on its system and, upon request, will attempt to obtain capacity and/or energy from a third party system.

3.2 In the event either party desires to purchase capacity to supply a portion of its Contingency Reserve Capacity rather than supply it from its own resources, each party will make available to the other such capacity to the extent that it is available.

SECTION 4 - COMPENSATION

4.1 Demand Charge

4.1.1 When Emergency Reserve Capacity is provided there will be no demand charge. If the party suffering the outage requires assistance for a longer period than the Emergency Period, then that party will purchase Daily Reserve Capacity, unless otherwise mutually agreed. When Daily Reserve Capacity is provided, the receiving party will pay the delivering party a reserve Demand Rate per kW per day not to exceed the rate calculated in accordance with Appendix A or B, whichever is applicable.

4.1.2 In the event the delivering party provides capacity to the receiving party from a third-party system, the receiving party will pay the delivering party a Demand Rate equal to the Demand Rate charged by the third party.

4.2 ENERGY

4.2.1 When the energy delivered is generated on the system of the delivering party, the receiving party will pay the delivering party a rate per KWH equal to (1) the out-of-pocket cost, plus (2) cost of transmission losses to make the delivery, plus (3) 10 percent of the sum of (1) and (2) under this Section, or 5 mills per KWH, whichever is less; or at option of the delivering party, the energy may be returned in kind.

4.2.2 For energy delivered by the delivering party from a third party the receiving party will pay the delivering party a rate per KWH equal to: (1) the rate per KWH paid to the third party; plus (2) the cost of supplying the associated transmission losses on the system of the delivering party; plus (3) one mill per KWH for miscellaneous and unquantifiable incremental costs incurred for transmission services; or by mutual agreement the energy may be returned in kind. In return-in-kind transactions the receiving party will pay the delivering party (1) the cost of supplying the associated transmission losses on the system of the delivering party; plus (2) one mill per KWH to provide compensation for miscellaneous and unquantifiable incremental costs incurred for transmission services.

4.3 TAXES

Where applicable, taxes will be added to the billings under 4.1 and 4.2 including but not limited to:

Support of South Carolina Public Service Commission

South Carolina Gross Receipts Tax

South Carolina Generation Tax

North Carolina Gross Receipts Tax

Any new or additional applicable taxes enacted after the date of this Service Schedule shall be included in billings under this Service Schedule.

APPENDIX A

DETERMINATION OF DEMAND RATE
PURSUANT TO SERVICE SCHEDULE A,
EMERGENCY RESERVE CAPACITY,
DAILY RESERVE CAPACITY, AND CONTINGENCY RESERVE CAPACITY

SOUTH CAROLINA ELECTRIC & GAS

This Appendix incorporates the provisions applicable to the pricing of capacity reserves being rendered under the Interconnection Agreement

SUMMARY OF METHODOLOGY

Calculation of the capacity rate is determined from cost published in FERC Form "1". The billing format methodology outlines page numbers, account titles, FERC account numbers and dollar amount for each component of rate base and capacity expenses. Calculations for production capacity cost are found on pages W1, W2, W3, W6, W7, W8, W9, W11, W12, and W15[2].

Rate base for production is comprised of plant in service, less reserve for depreciation, plus working capital (Total O&M – 8) and minus accumulated deferred income taxes. General and common plant and reserve are functionalized on a labor ratio (excluding administrative and general wages) methodology.

Capacity expenses are comprised of capacity related O&M expenses (per FERC), depreciation expense and taxes other than income (Ad Valorem and labor related taxes).

The capital structure is based on year end ratios of debt, preferred stock and common equity. The cost of each capital component is computed using year end embedded cost of debt, preferred stock and return on common equity as shown on page W7. Common equity will be the benchmark set by FERC for the period February 1, through April 30, 1988.

[2] Pages W4, W5, W10, W13, and W14 existed in previous version of this Interconnection Agreement and contained rate calculations for transmission capacity. These pages have been removed because SCE&G transmission rates under this agreement are based on SCE&G's approved FERC OATT.

SOUTH CAROLINA ELECTRIC & GAS COMPANY

RESERVES

Demand Rate

The demand rate for reserves includes:

1. A production carrying cost.

The total annual cost per KW is divided by 312 for a daily rate.

Transmission Use Rate

The transmission use rate for third-party transactions is the SCE&G Open Access Transmission Tariff (OATT) rate.

Income taxes are computed on the current statutory tax rates. Any billing month will be computed on the current Federal and State corporate rate as show on page W9.

All allocations and calculations for the production capacity rate are explained on pages W11 and W12.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
INFORMATIONAL SCHEDULES
FOR YEAR ENDING
DECEMBER 31, 1988

SOUTH CAROLINA ELECTRIC & GAS COMPANY
YEAR ENDING DECEMBER 31, 1988
RESERVES (1)

Demand Rate

Total Production Carrying Cost (Page W1)	\$42.93/KW/YR
	\$42.93/KW/YR/312 = \$0.14/KW/Day

Transmission Use Rate

Per the SCE&G OATT

(1) Note: Actual rates charged for these transactions will be as agreed by the two parties, but not to exceed these maximum rates.

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS
FOR YEAR ENDING DECEMBER 31, 1988

Line No.

Calculation of Capacity Related Revenue

Line No.		
1	Total Production Rate Base (Page W2)	$465,969,193
2	Rate of Return (Page W7)	X 10.28%
3	Required Return	$47,901,633
4	Composite Tax Factor (See Table 4, Page W9)	÷ .73271
5	Revenue Requirement for Rate Base	$65,375,978
6	Revenue for Capacity Related Expenses (Page W3)	$76,351,383
7	**Total Revenue Requirement**	**$141,727,361**

Calculation of Capacity Rate

$141,727,361 (Revenue Requirement) = $42.93 Total Production Carrying Cost/KW 3,301,000 KW (See Table 3, Page W8)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS

FERC FORM 1 PAGE #		FERC ACCT. #'s	Calendar Year 1988
			$
	Plant in Service		
204/205	Steam Production Plant	(310-316)	562,533,591
204/205	Nuclear Production Plant	(320-325)	-0-
204/205	Hydro Production Plant	(330-336)	240,833,927
206/207	Other Production Plant	(340-346)	18,430,761
	General Plant (See Page W11)	(389-398)	24,088,936
	Common Plant (See Page W11)	(389-398)	13,302,601
	Total Plant in Service		**859,189,816**
	Accumulated Provision for Depreciation		
219	Steam Production	108	223,108,232
219	Nuclear Production	108	-0-
219	Hydro Production	108	44,276,117
219	Other Production	108	15,363,829
	General (See Page W11)	108	18,352,754
	Common (See Page W11)	108	2,526,483
	Total Accumulated Depr.	108	**293,627,415**
	Working Cash		
	Total Working Capital (Total O&M ÷ 8) (Page W11)	(W3)	**5,369,765**
272	**Accumulated Deferred Income Taxes**		
	Steam Production (See Pg W6)	(281, 282, 283, & 190)	73,646,812
	Nuclear Production (See Pg W6)	(281, 282, 283, & 190)	-0-
	Hydro Production (See Pg W6)	(281, 282, 283, & 190)	24,120,842
	Other Production (see Pg W6)	(281, 282, 283, & 190)	1,480,328
	Gen. & Common (See Pg W11)	(281, 282, 283, & 190)	714,991
	Total Deferred Taxes	(281, 282, 283, & 190)	104,962,973
	Total Production Rate Base		**465,969,193**

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS

FERC FORM 1 PAGE #		FERC ACCT. #'s	Calendar Year 1988
			$
	Operation & Maintenance Expense		
320	Steam	(500,502,504-507,511, & 514)	15,555,311
320	Nuclear	(517,519,520,523-525,529, 532)	-0-
320/321	Hydro	(535-540, 541-543 & 545)	3,586,009
321	Other	(546, 548-554)	2,243,259
323	A&G (See Page W11)	(923-935 Less: 928)	21,573,542
	Total O&M		**42,958,121**
	Depreciation Expense		
336	Steam	403	13,565,300
336	Nuclear	403	-0-
336	Hydro	403	3,292,700
336	Other	403	1,039,300
	General (see Page W12)	403	496,656
	Common (see Page W12)	403	718,238
	Total Depreciation	403	**19,112,194**
	Other Taxes		
262	Operating Charge	408.1 & 409.1	534,716
	Payroll Taxes (See Page W12)	408.1 & 409.1	1,979,973
	County Property Taxes (See Page W12)	408.1 & 409.1	11,766,379
	Total Other Taxes	408.1 & 409.1	**14,281,068**
	Total Capacity Expenses		**76,351,383**

TABLE 1
SOUTH CAROLINA ELECTRIC & GAS COMPANY
ACCUMULATED DEFERRED INC. TAXES – 1988

FERC Acct. #	Steam	Other Hydro	Prod.	T&D	General & Common	Total	FERC Form 1 Page #
Acct 281	11,215,460	-	-	-	-	11,215,460	272-273
Acct 282	65,374,452	22,400,942	1,441,228	110,388,106	12,369,200	211,973,928	274-275
Acct 283	2,056,900	1,719,900	39,100	3,465,800	2,206,800	9,488,500	276-277
Less: Acct 190	-	-	-	-	12,627,487	12,627,487	234-234A
Total Accum Def. Inc. Taxes	78,646,812	24,120,842	1,480,328	113,853,906	1,948,513	220,050,401	

TABLE 2
SOUTH CAROLINA ELECTRIC & GAS COMPANY
COST OF CAPITAL
12 MONTHS ENDED DECEMBER 31, 1988

Component	Capitalization	Ratio	Embedded Cost/Rate	Overall Cost/Rate
	$	%	%	%
Long Term Debt	776,388,311	47.48	8.57	4.07
Preferred Stock	103,272,450	6.32	7.76	.49
Common Equity	755,467,715	46.20	12.38	(1) 5.72
Total	1,635,128,476	100.00		10.28

(1) FERC Benchmark Return on Common Equity for the period February 1, through April 30 of the current year.

TABLE 3
SOUTH CAROLINA ELECTRIC & GAS COMPANY
GENERATING STATION STATISTICS

NAME AND LOCATION OF STATION	FIRST AND LAST UNIT	RATING IN KILOWATTS NET PEAK CAPABILITY
Steam:		
Canadys – Canadys, SC	1962-67	430,000
Hagood – Charleston, SC	1947-51	94,000
McMeekin – Near Irmo, SC	1958	252,000
Urquhart – Beech Island, SC	1953-55	250,000
Wateree – Eastover, SC	1970-71	700,000
Williams – Charleston, SC	1973	560,000
Total Steam		**2,286,000**
IC Turbines:		
Burton, SC	1961	9,500
Charleston, SC	1961	9,500
Burton, SC	1963	9,500
Burton, SC	1963	9,500
Hardeeville, SC	1968	14,000
Canadys, SC	1968	14,000
Urquhart Turbines (2-17 MW & 13 MW)	1969	26,000
Coit Turbines (2 X 16 MW)	1969	30,000
Parr Turbines (2 X 14 MW)	1970	26,000
Parr Turbines (2 X 18 MW)	1971	34,000
Parr – Heat Recovery – Parr, SC	1925-29	28,000
Williams Turbines (2 X 27 MW)	1972	49,000
Total IC Turbines		**259,000**
Hydro:		
Columbia – Columbia, SC	1927-29	10,000
Neal Shoals – Union, SC	1905	5,000
Parr Shoals – Parr, SC	1914-21	14,000
Saluda – Near Irmo, SC	1930-71	206,000
Stevens Creek – Near Martinez, GA	1914-26	9,000
Fairfield Pump Storage – Parr, SC	1978	512,000
Total Hydro		**756,000**
Total (Excl. V.C. Summer Nuclear	as of 2-14-89	**3,301,000**
V. C. Summer Nuclear	2-14-89	590,000 (1)
Total (Incl. V. C. Summer Nuclear)	After 2-14-89	**3,891,000**

(1) S. C. Elec. & Gas Co.'s 2/3 Portion

SOUTH CAROLINA ELECTRIC & GAS COMPANY
DEVELOPMENT OF COMPOSITE
TAX FACTOR
TABLE 4
(YEAR ENDING DECEMBER 31, 1988)

Line No.		Debt (Col. 1)	Preferred (Col. 2)	Common (Col. 3)	Total (Col. 4)
1	Rate Base (Production)	465,969,193	465,969,193	465,969,193	465,969,193
2	Weighted Cost of Capital (Table 2)	x 4.07%	x .49%	x 5.72%	x 10.28%
3	Required Return	18,964,946	2,283,249	26,653,438	47,901,633
4	Revenue Effect (See Example)	÷ .99602	÷ .62451	÷ .062451	
		19,040,728	3,656,065	42,678,961	
5	Required Revenue				65,375,754
6	Composite Tax Factor (Col 4 Line 3: Col 4 Line 5)				73.271%

Example:

	1,000,000	100.00%
Less:		
(A) Gross Receipts & SCPSC Tax		
\$1,000,000 x .00398 =	3,980	.398%
(B) State Income Tax		
\$1,000,000 – 3,980 = 996,020 x 5.0%	49,801	4.980%
(C) Federal Income Tax		
\$1,000,000 – (49,801 - 3,980) = 946,219 x 34%	321,714	32.171%
(D) Total Taxes	375,495	37.549%
Additional Return	624,505	62.451%

Note # 1: SCPSC = Assessment for expenses of Commission
Note # 2: Any billing month will be charged the currently effective Federal or State Corporate Income rate

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CAPACITY RATE ANALYSIS
PRODUCTION

Page References are from Form 1

General & Common Plant Allocation

[1]Production Payroll (Pg 354) ÷ PT&D Payroll (Pg 354) x General Plant (Pg 206-207)

[2]Production Payroll (Pg 354) ÷ PT&D Payroll (Pg 354) x Common Plant (Pg 356b) + GENCO common plant + Fuel Co. Common Plant (Pg 356b)

General & Common Accumulated Provision for Depreciation Allocation

[1]Production Payroll (Pg 354) ÷ PT&D Payroll (Pg 354) x General Accumulated Provision (Pg 219)

[2]Production Payroll (Pg 354) ÷ PT&D Payroll (Pg 354) x Common Accumulated Provision (Pg 356b) + GENCO Common Accumulated Provision + Fuel Co. Common Accumulated Provision (Pg 356b)

Working Cash Computation

Total O&M (Exclusive of Purchased Power and Nuc. Fuel.) from W3 ÷ 8 (45 day formula)

Accumulated Deferred Income Taxes

[1]Production Payroll (Pg. 354) ÷ PT&D Payroll (Pg 354) x General & Common Deferred Taxes (Table 1)

Administrative & General Expenses Allocation

[1]Production Payroll (Pg 354) ÷ PT&D Payroll (Pg 354) x (Total A&G less Account 928)

[1]Includes GENCO, Excludes Nuclear (W15)
[2]Excludes Nuclear (W15)

General & Common Depreciation Expenses Allocation

[1]Production Payroll (Pg 354) ÷ PT&D Payroll (Pg 354) x General Provision (Pg 336)

[2]Production Payroll (Pg 354) ÷ PT&D Payroll (Pg 354) x Common Provision (Pg 336) + GENCO Common Provision (Pg 336)

Other Taxes

Payroll Taxes: [2]Production Payroll (Pg 354) ÷ PT&D Payroll (Pg 354) x Payroll taxes (Pg 263, Lines 3, 4, & 13) & GENCO Payroll Taxes (P. 263, Lines 3, 4, & 8)

County Property Tax: Total Production Plant (W2) ÷ Total Plant (Pg 207) x Property tax (Pg. 263, Line 16) & GENCO Property Tax (P. 263)

Rate of Return

The allowable rate of return shall be computed using capitalization figures and debt and preferred embedded costs as of December 31. The cost of equity shall be at the stated FERC Benchmark Rate of Return for the period February 1 through April 30.

1 Includes GENCO, excludes Nuclear (W15)
2 Excludes Nuclear (W15)

SOUTH CAROINA ELECTRIC & GAS COMPANY
FUNCTIONALIZATION OF PRODUCTION PAYROLL
FOR YEAR ENDING DECEMBER 31, 1988

	FERC Form 1 Page #	Operation $	Maintenance $	Total $
Production				
Steam		7,174,094	3,645,047	10,819,141
Hydro		2,107,667	716,917	2,824,584
Nuclear		15,761,043	2,365,730	18,126,773
Other Power		34,847	187,147	221,994
Total Production	354	25,077,651	6,914,841	31,992,492

APPENDIX B

DETERMINATION OF DEMAND RATE
PURSUANT TO SERVICE SCHEDULE A,
EMERGENCY RESERVE CAPACITY,
DAILY RESERVE CAPACITY, AND
CONTINGENCY RESERVE CAPACITY

DUKE ENERGY PROGRESS, LLC

This Appendix incorporates the provisions applicable to pricing of the reserve service being rendered under this Interconnection Agreement. All investments associated with production will be based on a projected, end-of-year test period. In addition to the rates calculated under the following provisions DEP will provide transmission services in accordance with the provisions of DEP's Joint Open Access Transmission Tariff. Unless otherwise mutually agreed to by DEP and SCE&G, the rate shall be calculated on an annual basis and will be applicable to service rendered during the 12 months beginning July 1 of the test year.

RESERVE

The rate for Reserve sales consists of a production demand rate.

The annual production demand rate is the sum of the total production demand cost (Appendix page 3 of 8) and applicable taxes (Appendix page 5 of 8). The annual production demand rate per kW is divided by 312 for a daily rate.

TOTAL PRODUCTION DEMAND COST

The total production demand cost is determined by subtracting the accumulated deferred income tax credit per kW from the production demand cost per kW and adding the demand-related production expense per kW and the allowed CWIP per kW.

An explanation of the components used in calculating the total production demand cost is as follows:

A. Production demand cost per kW – This cost is the sum of the production-related demand costs per kW of the generating plants contributing to the sale. Individual generating plant production related demand cost per kW is the product of the weighted investment per kW for that plant and the applicable annual carrying charge. The annual carrying charge consists of the components listed below and explained on pages 7 and 8 of 8 of this appendix.

1. Cost of Capital
2. Income Taxes
3. Ad Valorem and Labor-Related Taxes
4. Depreciation
5. Decommissioning Expenses
6. Administrative and General Expenses
7. General Plant
8. Working Capital
   (a) Cash Working Capital
   (b) Materials and Supplies
   (c) Prepayments

B. Accumulated deferred income tax credit per kW – This credit is determined by summing the products of the weighted accumulated deferred income tax per kW and the annual carrying charge, consisting of the cost of capital and income tax components, for each generating plant contributing to the sale.

C. Demand-related production expense per kW – This cost is determined by summing the products of demand-related production expense per kW and the percent participation for each generating plant contributing to the sale. The demand-related portion of

Accounts 500-554 is determined through an analysis of each FERC account. The purchased capacity, including related O&M from jointly owned units, is included in the calculation of demand-related production expenses. This purchased capacity is booked in Account 555.

D. Allowed CWIP per kW – This cost is determined by summing the products of the FERC allowed production-related CWIP and the annual carrying charge, consisting of the cost of capital and income tax components for each generating plant contributing to the sale where CWIP is projected for the test period.

APPLICABLE TAXES

The Service Schedule with which this Appendix is used provides for adding to the cost any taxes which might be applicable to the transactions. Such taxes may include, but are not limited to:

Support of South Carolina Public Service Commission
South Carolina Gross Receipts Tax
South Carolina Excise Tax (kWh Tax)
North Carolina Gross Receipts Tax
North Carolina Sales Tax

COST FOR CAPACITY RESERVES

The cost for capacity reserves is determined by taking 20 percent of the total production demand cost.

CARRYING CHARGES

The carrying charges will include the appropriate following components which are determined using projected values with an end-of-year test period:

1. Cost of Capital – The capital structure is based on end-of-year ratios of debt, preferred stock, and common equity. The cost of each capital component is computed using the end-of-year embedded cost of debt and preferred stock and the return on common equity as set forth in the Exhibit No. 1 to this Appendix as the same may be changed subject to appropriate filing with the FERC.

2. Income Taxes – Income taxes are the product of the current statutory tax rates applied to the return on preferred stock and common equity as computed above.

3. Ad Valorem and Labor-Related Taxes – This component is the result of dividing the sum of ad valorem and labor-related taxes by the total end-of-year net plant investment in the computation period.

4. Depreciation – The depreciation rates are the rates last allowed by the FERC adjusted to apply to net plant investment. These rates differ for the type of plant. The allowed rates are adjusted by the ratio of gross plant investment to net plant investment.

5. Decommissioning – The decommissioning component will only be applicable in the case of nuclear production. The annual decommissioning accrual is divided by the end-of-year net nuclear production plant investment to determine this percentage.

6. Administrative and General Expenses – The A&G expenses for the computation period are allocated between power production plant, transmission plant, and distribution plant based on the labor ratios of these items. The A&G expenses so determined are divided by the end-of-year net plant investment for power production plant.

7. General Plant – The general plant is allocated between power production plant, transmission plant, and distribution plant based on the labor ratios of these items. The carrying

charge applicable to general plant consists of the cost of capital, income taxes, ad valorem and labor-related taxes, and depreciation (all as determined above). This carrying charge is applied to the general plant applicable to power production. The cost of general plant applicable to power production is divided by its respective end-of-year net plants.

8. Working Capital – Working capital is composed of the three portions defined below: cash working capital, materials and supplies, and prepayments. A carrying charge, consisting of cost of capital and income taxes (both described above), will be applied to each of the three in determining the annual cost for working capital. The working capital percentage is determined by dividing the annual cost by the end-of-year net plant investment.

a. Cash Working Capital – This portion is calculated by taking one-eighth of the applicable operation and maintenance expenses. In the case of production, the O&M expenses should be exclusive of purchased power and nuclear fuel.

b. Materials and Supplies – This is the end-of-year balance of the appropriate materials and supplies.

c. Prepayments – This is the end-of-year balance of the appropriate prepaid expenditures, such as taxes and insurance.

DEMAND RATE FOR RESERVE SALES

Year Ending December 31, 1989

Annual updates, pursuant to the Appendix, will require a filing when changes are made to the return on common equity, CWIP balances, and acquisition adjustments and that such filings will be governed by the applicable parts of Sections 35.13 and 35.26 of the Commission's Regulations, as modified by Order No. 448 or any superseding Commission Regulation or Order.

RESERVE

Demand Rate

Total Production Demand Cost	$44.03 /kW/year		
Applicable Taxes	0.00 /kW/year		
Total	$44.03 /kW/year / 312	=	$0.141 /kW/day

TOTAL PRODUCTION DEMAND COST

Year Ending December 31, 1989

1.	Production Demand Cost/kW	$42.67	/kW/year
2.	Less: Accumulated Deferred Income Tax/kW	4.93	/kW/year
3.	Plus: Demand-Related Production Expenses/kW	6.29	/kW/year
4.	Plus: Allowed CWIP/kW	0.00	/kW/year
5.	Total Production Demand Cost/kW	$44.03	/kW/year

PRODUCTION DEMAND COST

(1) Generating Plants	(2) Net Plant Investment	(3) Installed Capacity (MW)	(4) Investment /kW (2) / (3)	(5) Percent Participation	(6) Weighted Investment Cost/kW (4) x (5)	(7) Annual Carrying Charge	(8) Annual Carrying Cost/kW (6) x (7)
Asheville	$27,489,000	392	70.13	4.11%	2.88	24.63%	$ 0.71
Cape Fear	$32,904,000	316	104.13	8.42%	8.77	24.63%	2.16
Lee	$19,945,000	407	49.00	10.33%	5.06	24.63%	1.25
Mayo (1)	$354,547,490	661	536.38	17.40%	93.33	24.63%	22.99
Robinson	$12,631,000	174	72.59	2.73%	1.98	24.63%	0.49
Roxboro	$263,464,000	2,371	111.12	42.62%	47.36	24.63%	11.66
Sutton	$60,364,000	613	98.47	10.83%	10.66	24.63%	2.63
Weatherspoon	$10,780,000	176	61.25	3.30%	2.02	24.63%	0.50
Brunswick	$610,688,000	1,290	473.40	0.26%	1.23	22.40%	0.28

Total Production Demand Cost $42.67 /kW/year

(1) Includes capacity charge capital costs and buy-back capacity from another part owner of Mayo Unit No. 1.

$$\$341{,}523{,}000 + \frac{\$3{,}207{,}932}{24.63\%} = \$354{,}547{,}490$$

625 MW + 36 MW = 661 MW

ACCUMULATED DEFERRED INCOME TAX

(1) Generating Plants	(2) Accumulated Deferred Income Tax	(3) Installed Capacity (MW)	Accumulated Deferred Income Tax/kW (2) / (3)	(5) Percent Participation	(6) Weighted Accumulated Deferred Income Tax Cost/kW (4) x (5)	(7) Annual Carrying Charge	(8) Accumulated DIT/kW (6) x (7)
Asheville	$6,623,000	392	16.90	4.11%	0.69	13.93%	$0.10
Cape Fear	$4,983,000	316	15.77	8.42%	1.33	13.93%	$0.18
Lee	$4,375,000	407	10.75	10.33%	1.11	13.93%	$0.15
Mayo	$61,814,000	625	98.90	17.40%	17.21	13.93%	$2.40
Robinson	$2,867,000	174	16.48	2.73%	0.45	13.93%	$0.06
Roxboro	$62,996,000	2,371	26.57	42.62%	11.32	13.93%	$1.58
Sutton	$15,988,000	613	26.08	10.83%	2.82	13.93%	$0.39
Weatherspoon	$1,504,000	176	8.55	3.30%	0.28	13.93%	$0.04
Brunswick	$114,359,000	1,290	88.65	0.26%	0.23	13.93%	$0.03
						Total Accumulated DIT	$4.93 /kW/year

DEMAND-RELATED PRODUCTION EXPENSE

(1) Generating Plants	(2) Demand-Related Production Expense	(3) Installed Capacity (MW)	(4) Demand-Related Production Expense/kW (2) / (3)	(5) Percent Participation	(6) Weighted Demand-Related Production Expense/kW (4) x (5)
Asheville	$3,275,908	392	8.36	4.11%	$0.34
Cape Fear	$3,574,254	316	11.31	8.42%	$0.95
Lee	$3,043,852	407	7.48	10.33%	$0.77
Mayo (2)	$3,612,449	661	5.47	17.40%	$0.95
Robinson	$1,584,039	174	9.10	2.73%	$0.25
Roxboro	$9,515,784	2,371	4.01	42.62%	$1.71
Sutton	$4,188,124	613	6.83	10.83%	$0.74
Weatherspoon	$2,316,999	176	13.16	3.30%	$0.43
Brunswick	$72,120,046	1,290	55.91	0.26%	$0.15
			Total Demand-Related Production Expense		$6.29 /kW/year

(2) Includes capacity charge demand-related O&M and buy-back capacity from another part owner of Mayo Unit No.1.

$3,111,867 + $500,582 = $3,612,449

625 MW + 36 MW = 661 MW

CONSTRUCTION WORK IN PROGRESS

(1) Generating Plants	(2) Allowed Construction Work In Progress	(3) Installed Capacity (MW)	(4) Cost/kW (2) / (3)	(5) Percent Participation	(6) Weighted Cost/kW (4) / (5)	(7) Annual Carrying Charge	(8) Allowed CIP/kW (6) x (7)
Asheville	$0	392	0.00	4.11%	0.00	13.93%	$0.00
Cape Fear	$0	316	0.00	8.42%	0.00	13.93%	$0.00
Lee	$0	407	0.00	10.33%	0.00	13.93%	$0.00
Mayo	$0	625	0.00	17.40%	0.00	13.93%	$0.00
Robinson	$0	174	0.00	2.73%	0.00	13.93%	$0.00
Roxboro	$0	2,371	0.00	42.62%	0.00	13.93%	$0.00
Sutton	$0	613	0.00	10.83%	0.00	13.93%	$0.00
Weatherspoon	$0	176	0.00	3.30%	0.00	13.93%	$0.00
Brunswick	$0	1,290	0.00	0.26%	0.00	13.93%	$0.00

Total CWIP $0.00 /kW/year

CARRYING CHARGE RATE FOR PRODUCTION COST

	Steam Production	Nuclear Production
Cost of Capital	10.19%	10.19%
Income Taxes	3.74%	3.74%
Ad Valorem and Labor-Related Taxes	0.92%	0.92%
Depreciation	5.76%	3.89%
Decommissioning Expense	0.00%	0.57%
A&G Expenses	2.28%	2.28%
General Plant	0.65%	0.65%
Working Capital		
Cash	1.06%	0.14%
Materials and Supplies	0.00%	0.00%
Prepayments	0.03%	0.02%
Total	24.63%	22.40%

PRODUCTION CARRYING CHARGES

All year-end investments are from 1989 projected values. Original cost must be reduced by depreciation.

1. Cost of Capital (3)

	% Capital Structure	Cost of Each %	Cost Component
Debt	49.54%	8.45%	4.19%
Preferred	6.82%	8.76%	0.60%
Equity	43.64%	12.38%	5.40%
Total			10.19%

2. Income Taxes

State	6.67%
Federal	34.00%

Income Tax on Preferred and Common Equity:

Net Income Before Taxes				100.00%
State Income Taxes				6.67%
				93.33%
Federal	93.33%	x	34.00%	31.73%
				61.60%

Income Tax

$$\frac{1 - .6160}{.6160} \times (0.60 + 5.40) = 3.74\%$$

3. Ad Valorem and Labor-Related Taxes (4)

$$\frac{\$59{,}402{,}000}{\$6{,}438{,}127{,}000} = 0.92\%$$

4. Depreciation (5)

These are the current FERC approved composite rates for the applicable accounts. These composite rates are then adjusted to apply to net plant investment.

Steam Production $$3.43\% \times \frac{\$1{,}324{,}039{,}000}{\$788{,}481{,}000} = 5.76\%$$

Nuclear Production $$3.19\% \times \frac{\$4{,}406{,}238{,}000}{\$3{,}615{,}512{,}000} = 3.89\%$$

(3) FERC Benchmark Return on Common Equity for the period February 1, 1989 to April 30, 1989.
(4) Analysis of Company books.
(5) Analysis of Company books.

5. Decommissioning Expenses

Nuclear Production	$20,728,000 / $3,615,512,000	=	0.57%

6. A&G Expenses (6)

$101,763,906 / $4,466,281,000	=	2.28%

7. General Plant (7)

Carrying Charges

10.19%	+	3.74%	+	0.92%	+	4.95%		=	19.80%
		19.80%		x		$146,481,206		=	$29,003,279
						29,003,279 / $4,466,281,000		=	0.65%

8. Working Capital (8)

a. Cash

Carrying Charge	10.19%	+	3.74%	=	13.93%
Steam Production					
	1/8	x	$478,836,000	=	$59,854,500
	13.93%	x	$59,854,500	=	$8,337,732
			$8,337,732 / $788,481,000	=	1.06%
Nuclear Production					
	1/8	x	$286,234,000	=	$35,766,750
	13.93%	x	$35,766,750	=	$4,982,308
			$4,982,308 / $3,615,512,000	=	0.14%

(6) Analysis of Company books. Power Production-related A&G allocated on the basis of Labor.
(7) Analysis of Company books. Power Production-related General Plant allocated on the basis of Labor.
(8) Analysis of Company books.

b. Materials and Supplies

Nuclear and Steam Production		$0		
13.93%	x	$0	=	0.00%

c. Prepayments

Steam Production

13.93%	x	$1,665,933	=	$232,064
		$232,064 / $788,481,000	=	0.03%

Nuclear Production

13.93%	x	$5,544,057	=	$772,287
		$772,287 / $3,615,512,000	=	0.02%

SUPPLEMENTAL INFORMATION
DUKE ENERGY PROGRESS, LLC

DERIVATION OF LABOR RATIOS FOR A&G AND GENERAL PLANT ALLOCATIONS

1.	Distribution of Salaries and Wages		
	a.	Production	$130,888,000
	b.	Transmission	7,309,000
	c.	Distribution	38,845,000
	d.	Total	$177,042,000
2.	Labor Ratios		
	a.	Production (l.a./l.d.)	0.7393
	b.	Transmission (l.b./l.d.)	0.0413
	c.	Distribution (1.c./l.d.)	0.2194
	d.	Total	1.0000
3.	A&G Expense (page 9 of 10)		
	a.	Total A&G Expense	$137,649,000
	b.	Allocated Production A&G Expense (3.a. x 2.a.)	$101,763,906
4.	General Plant Expense (page 9 of 10)		
	a.	Total Net Generating Plant	$198,135,000
	b.	Allocated Net Production-related General Plant (4.a. x 2.a)	$146,481,206