Terry A. Davis
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GULF POWER
A SOUTHERN COMPANY

March 27, 2009

FILED-RECEIVED-FPSC
09 MAR 30 AM 9:15
COMMISSION
CLERK

Ms. Ann Cole
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Ms. Cole:

Re: Docket No. 070673-EI, Order Number PSC-07-1007-FOF-EI
Application of Gulf Power Company for authority to receive common equity contributions and to issue and sell securities

An original and three copies of the Consummation Report dated March 27, 2009, and four copies of the exhibits are enclosed with this letter for filing in the above referenced docket.

Sincerely,

Terry A. Davis

ck

Enclosures

cc: E. W. Boston, Southern Company Services
J. A. Stone, Beggs & Lane

DOCUMENT NUMBER-DATE
02776 MAR 30 09
FPSC-COMMISSION CLERK

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Application of Gulf Power Company for authority to receive common equity contributions and to issue and sell securities.	)))))	Docket No.: 070673-EI Filed: March 27, 2009

TO THE HONORABLE FLORIDA PUBLIC SERVICE COMMISSION:

CONSUMMATION REPORT

GULF POWER COMPANY ("Gulf Power", "Gulf", or "the Company"), by and through its undersigned representative, and pursuant to Rule 25-8.009, Florida Administrative Code, and the reporting requirements of Order No. PSC-07-1007-FOF-EI entered in Docket No. 070673-EI on December 19, 2007, hereby reports for the fiscal year ending December 31, 2008:

A. 1. After negotiated arrangements on April 2, 2008, Gulf Power Company (the "Company") entered into a $110,000,000 Term Loan Agreement with Lloyds TSB Bank PLC, (the "Bank"), as the holder of two promissory notes, due April 8, 2011. The first promissory note, dated April 8, 2008, is payable in the principal amount of $80,000,000. The second promissiory note, dated June 9, 2008, is payable in the principal amount of $30,000,000. The promissory notes are subject to the terms and conditions set forth in the Term Loan Agreement and may be accelerated as therein provided.

2. The proceeds from the promissory notes were used by the Company for general corporate purposes.

3. The interest rate for each monthly interest period shall be equal to the sum of the Adjusted LIBOR, as defined in the promissory note, for each subsequent interest period plus 0.45 percent. The principal of the promissory note may be prepaid.

4. The promissory note is unsecured.

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Pursuant to Rule 25-8.009, F.A.C., Gulf Power Company submits the following documents relative to the issuance of the above referenced notes:

A. Exhibits for $110,000,000 Promissory Notes:

1. Promissory Notes dated April 8, 2008 and June 9, 2008 executed by Gulf Power Company to Lloyds TSB Bank PLC.
2. Term Loan Agreement dated as of April 2, 2008 between Lloyds TSB Bank PLC and Gulf Power Company.
3. Description of Holder.
4. Report of Expenses.
5. 10-K for the year ended December 31, 2008, filed with the Securities and Exchange Commission, File No. 0-2429. On page II-266 of the 10-K is shown the Pro Forma Capitalization and Pretax Interest Coverage Statements. On page II-270 of the 10-K is shown the debt interest and preferred/preference stock dividend requirements.

Respectfully submitted,

Terry A. Davis

Terry A. Davis
Assistant Secretary and Assistant Treasurer

Dated March 27, 2009

PROMISSORY NOTE

US$80,000,000 April 8, 2008

FOR VALUE RECEIVED, Gulf Power Company (the "Borrower") unconditionally promises to pay to the order of Lloyds TSB Bank PLC, acting through its New York Branch (the "Lender"), to and for any account designated by the Lender, the principal sum of Eighty Million Dollars ($80,000,000) pursuant to the Term Loan Agreement, dated as of April 2, 2008, between the Borrower and the Lender (as the same may be amended, supplemented or otherwise modified from time to time, the "Loan Agreement").

The outstanding principal of this Note and any accrued interest thereon shall be repaid as set forth in the Loan Agreement, with final payment on the Maturity Date (as defined in the Loan Agreement).

All payments of principal and interest on this Note shall be payable in lawful money of the United States of America in immediately available funds without set-off, defense or counterclaim.

This Note is issued pursuant to the terms of the Loan Agreement and is subject to the terms and conditions and entitled to the benefits therein provided. Upon the occurrence of an Event of Default (as defined in the Loan Agreement), the principal of and the accrued interest on this Note may become due and payable in the manner and with the same effect as provided in the Loan Agreement, without presentment, demand, protest or notice of any kind unless otherwise expressly required therein.

Failure or delay of the holder of this Note to enforce any provision of this Note shall not be deemed a waiver of any such provision, nor shall the holder of this Note be estopped from enforcing any such provision at a later time. Any waiver of any provision hereof must be in writing. This Note shall be governed by, and interpreted in accordance with, the law of the State of New York.

DOCUMENT NUMBER-DATE
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GULF POWER COMPANY

By: Constance J. Erickson

Constance J. Erickson
Comptroller

By: Terry A. Davis

Terry A. Davis
Assistant Secretary and Assistant Treasurer

PROMISSORY NOTE

US$30,000,000 June 9, 2008

FOR VALUE RECEIVED, Gulf Power Company (the "Borrower") unconditionally promises to pay to the order of Lloyds TSB Bank PLC, acting through its New York Branch (the "Lender"), to and for any account designated by the Lender, the principal sum of Thirty Million Dollars ($30,000,000) pursuant to the Term Loan Agreement, dated as of April 2, 2008, between the Borrower and the Lender (as the same may be amended, supplemented or otherwise modified from time to time, the "Loan Agreement").

The outstanding principal of this Note and any accrued interest thereon shall be repaid as set forth in the Loan Agreement, with final payment on the Maturity Date (as defined in the Loan Agreement).

All payments of principal and interest on this Note shall be payable in lawful money of the United States of America in immediately available funds without set-off, defense or counterclaim.

This Note is issued pursuant to the terms of the Loan Agreement and is subject to the terms and conditions and entitled to the benefits therein provided. Upon the occurrence of an Event of Default (as defined in the Loan Agreement), the principal of and the accrued interest on this Note may become due and payable in the manner and with the same effect as provided in the Loan Agreement, without presentment, demand, protest or notice of any kind unless otherwise expressly required therein.

Failure or delay of the holder of this Note to enforce any provision of this Note shall not be deemed a waiver of any such provision, nor shall the holder of this Note be estopped from enforcing any such provision at a later time. Any waiver of any provision hereof must be in writing. This Note shall be governed by, and interpreted in accordance with, the law of the State of New York.

GULF POWER COMPANY

By: Constance J Erickson

Constance J. Erickson
Comptroller

By: Terry A. Davis

Terry A. Davis
Assistant Secretary and Assistant Treasurer

TERM LOAN AGREEMENT

Dated as of April 2, 2008

Between

GULF POWER COMPANY

And

LLOYDS TSB BANK PLC

DOCUMENT NUMBER-DATE
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EXHIBIT A: Form of Term Loan Note
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SCHEDULE 1: Notice Addresses

TERM LOAN AGREEMENT (this "Loan Agreement"), dated as of April 2, 2008, is entered into between GULF POWER COMPANY, a Florida corporation (the "Borrower"), and LLOYDS TSB BANK PLC (the "Lender").

RECITAL

WHEREAS, the Borrower has requested that the Lender provide a term loan facility, and the Lender is willing to do so on the terms and conditions set forth herein.

NOW, THEREFORE, IN CONSIDERATION of the premises and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the parties hereto agree as follows:

SECTION 1: DEFINITIONS AND ACCOUNTING TERMS

SECTION 1.1 Definitions. As used herein, the following terms shall have the meanings herein specified unless the context otherwise requires. Defined terms herein shall include in the singular number the plural and in the plural the singular:

"Affiliate" means, with respect to any Person, any other Person directly or indirectly controlling (including but not limited to all directors and officers of such Person), controlled by or under direct or indirect common control with such Person. A Person shall be deemed to control a corporation if such Person possesses, directly or indirectly, the power (i) to vote twenty percent (20%) or more of the securities having ordinary voting power for the election of directors of such corporation or (ii) to direct or cause direction of the management and policies of such corporation, whether through the ownership of voting securities, by contract or otherwise.

"April Loan" shall mean the term loan made available by the Lender to the Borrower in the principal amount of Eighty Million Dollars ($80,000,000) to be made on April 8, 2008, subject to the terms and conditions hereunder.

"April Note" shall mean the promissory note in substantially the form of Exhibit A attached hereto in the principal amount of the April Loan and dated April 8, 2008.

"Bankruptcy Code" means the Bankruptcy Code in Title 11 of the United States Code, as amended, modified, succeeded or replaced from time to time.

"Borrower" means Gulf Power Company, a Florida corporation, or such other Person as may become the Borrower pursuant to Section 8.2(b)(ii).

"Borrower Obligations" means, without duplication, all of the obligations of the Borrower to the Lender, whenever arising, under this Loan Agreement, the Term Loan Note or any of the other Loan Documents.

"Borrowing Dates" shall mean each of April 8, 2008 and June 9, 2008.

"Business Day" means any day other than (i) a Saturday, a Sunday or a legal holiday, (ii) a day on which the Lender specifically or banking institutions generally are authorized or required by law or other governmental action to close in New York, New York or (iii) a day on which dealings in dollar deposits are not carried on between banks in the London Interbank Eurodollar market, provided that clause (iii) shall be disregarded in connection with calculation of or payment of interest at the Substitute Rate or the payment of principal of a Loan bearing interest at the Substitute Rate.

"Capitalization" means, with respect to the Borrower and its consolidated Subsidiaries (determined on a consolidated basis), without duplication, the sum of (a) the aggregate of (i) the capital stock (but excluding treasury stock and capital stock subscribed and unissued), other equity accounts (including retained earnings and paid-in capital but excluding accumulated other comprehensive income and loss) of the Borrower as the same appears on its balance sheet prepared in accordance with GAAP as of the date of determination and (ii) the principal or liquidation amount of Hybrid Securities provided such amount of Hybrid Securities is not Indebtedness and (b) the amount of all Indebtedness as of the same date.

"Change of Control" means the failure of The Southern Company, a Delaware corporation, to own more than fifty-one (51%) of the outstanding shares of the capital stock of the Borrower entitled to vote generally for the election of directors of the Borrower.

"Closing Date" means the date hereof.

"Code" means the Internal Revenue Code of 1986, as amended from time to time.

"Controlled Group" means (a) the controlled group of corporations as defined in Section 414(b) of the Code and the applicable regulations thereunder or (b) the group of trades or businesses under common control as defined in Section 414(c) of the Code and the applicable regulations thereunder, of which the Borrower is a part or may become a part.

"corporation" includes corporations, partnerships, limited liability companies, associations, companies, statutory trusts and business trusts.

"Debt Rating" means any credit rating of the Borrower by S&P, Moody's or Fitch.

"Default" means any event, act or condition which, with notice or lapse of time, or both, would constitute an Event of Default.

"Default Rate" means an interest rate equal to the interest rate otherwise applicable to the Borrower Obligations plus 2% per annum.

"Dollars" and "$" means dollars in lawful currency of the United States of America.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and the regulations promulgated and the rulings issued thereunder.

"ERISA Affiliate" means each person (as defined in Section 3(9) of ERISA) which together with the Borrower or any Subsidiary of the Borrower would be deemed to be a member of the same "controlled group" within the meaning of Section 414(b), (c), (m) and (o) of the Code.

"Eurodollar Rate" means, with respect to the Loans, for each Interest Period applicable thereto, a rate per annum determined pursuant to the following formula:

$$\text{"Eurodollar Rate"} = \frac{\text{Interbank Offered Rate}}{\text{1- Eurodollar Reserve Percentage}}$$

"Eurodollar Reserve Percentage" means for any day, that percentage (expressed as a decimal) which is in effect from time to time under Regulation D, as the maximum reserve requirement (including, without limitation, any basic, supplemental, emergency, special or marginal reserves) applicable with respect to "Eurocurrency liabilities" as that term is defined in Regulation D (or against any other category of liabilities that includes deposits by reference to which the interest rate of the Loans is determined), whether or not the Lender has any Eurodollar liabilities subject to such reserve requirement at that time. The Loans shall be deemed to constitute Eurodollar liabilities and as such shall be deemed subject to reserve requirements without benefits of credits for proration, exceptions or offsets that may be available from time to time to the Lender. The Eurodollar Rate shall be adjusted automatically on and as of the effective date of any change in the Eurodollar Reserve Percentage.

"Event of Default" has the meaning specified in Section 9.1.

"Federal Funds Effective Rate" means, for any day, an interest rate per annum equal to the weighted average of the rates on overnight Federal funds transactions with members of the Federal Reserve System arranged by Federal funds brokers on such day, as published for such day (or, if such day is not a Business Day, for the immediately preceding Business Day) by the Federal Reserve Bank of New York, or, if such rate is not so published for any day with is a Business Day, the average of the quotations at approximately 11:00 a.m. (New York time) on such day on such transactions received by the Lender from three Federal funds brokers of recognized standing selected by the Lender in its sole discretion.

"Fitch" means Fitch, Inc., or any successor or assignee of the business of such company in the business of rating securities.

"FPSC" means the Florida Public Service Commission.

"GAAP" means generally accepted accounting principles in the United States applied on a consistent basis and subject to Section 1.3.

"Governmental Authority" means any federal, state, local or foreign court or governmental agency, authority, instrumentality or regulatory body.

"Guaranty Obligations" means, in respect of any Person, any legally enforceable obligation, contingent or otherwise, of such Person directly or indirectly guaranteeing any Indebtedness of another Person.

"Hybrid Securities" means (i) any Trust Preferred Obligations and any Junior Subordinated Deferred Interest Debt Obligations and (ii) any other securities of the Borrower (other than capital stock of the Borrower) that are afforded equity treatment by any rating agency at the time of issuance of such securities.

"Indebtedness" means, as to the Borrower and its consolidated Subsidiaries (determined on a consolidated basis), without duplication: (i) all obligations of the Borrower and such Subsidiaries for borrowed money or evidenced by bonds, debentures, notes or similar instruments, including, without limitation, the obligations of the Borrower under the SCFC Notes; (ii) all obligations of the Borrower and such Subsidiaries for the deferred purchase price of property or services (except trade accounts payable arising in the ordinary course of business); (iii) all capital lease obligations of the Borrower and such Subsidiaries; (iv) all Indebtedness of others secured by a Lien on any properties, assets or revenues of the Borrower and such Subsidiaries (other than stock, partnership interests or other equity interests of the Borrower and such Subsidiaries in entities other than the Borrower or any of its Subsidiaries) to the extent of the lesser of the value of the property subject to such Lien or the amount of such Indebtedness; (v) all Guaranty Obligations; and (vi) all non-contingent obligations of the Borrower and such Subsidiaries under any letters of credit or bankers' acceptances. It is understood and agreed that, for the purpose of calculations under Section 7.11, Indebtedness (including Guaranty Obligations) shall not include any (A) Off Balance Sheet Indebtedness existing as of the Closing Date other than obligations of any partnership or joint venture that are recourse to the Borrower or any of its Subsidiaries, (B) refinancing of Off Balance Sheet Indebtedness described in clause (A) above in a principal amount not in excess of that outstanding as of the date of such refinancing (C) Securitized Storm Bonds, or (D) any Indebtedness with respect to Hybrid Securities; provided that the aggregate amount of Hybrid Securities excluded from this definition of Indebtedness at any time shall not exceed 15% of Capitalization; provided, further, that any Hybrid Securities with a maturity date prior to the Maturity Date shall be included in this definition of Indebtedness and provided, however, that the amount of any mandatory principal amortization of such Hybrid Securities prior to the Maturity Date shall be included in this definition of Indebtedness for such purposes.

"Interbank Offered Rate" means, with respect to the Loans for each Interest Period applicable thereto:

(a) the rate per annum equal to the rate determined by the Lender to be the offered rate that appears on the page of the Telerate screen (or any successor thereto) that displays an average British Bankers Association Interest Settlement Rate for deposits in Dollars (for delivery on the first day of such Interest Period) with a term equivalent to such Interest Period, determined as of approximately 11:00 a.m. (London time) two (2) Business Days prior to the first day of such Interest Period, or

(b) if the rate referenced in the preceding clause (a) does not appear on such page or service or such page or service shall not be available, the rate per annum equal to the rate determined by the Lender to be the offered rate on such other page or other service that displays an average British Bankers Association Interest Settlement Rate for deposits in Dollars (for delivery on the first day of such Interest Period) with a term equivalent to such Interest Period, determined as of approximately 11:00 a.m. (London time) two (2) Business Days prior to the first day of such Interest Period, or

(c) if the rates referenced in the preceding clauses (a) and (b) are not available, the rate per annum determined by the Lender as the rate of interest at which deposits in Dollars for delivery on the first day of such Interest Period in same day funds in the approximate amount of the Loans and with a term equivalent to such Interest Period would be offered to leading banks in the London Interbank Eurodollar market at their request at approximately 4:00 p.m. (London time) two (2) Business Days prior to the first day of such Interest Period.

"Interest Payment Date" means the last day of each Interest Period, the Maturity Date and the date of any prepayment.

"Interest Period" means as to each Loan, a period of one month's duration, commencing, in the case of the first Interest Period, on the applicable Borrowing Date, and in the case of each subsequent Interest Period, on the last day of the preceding Interest Period, provided, however, (i) if any Interest Period would end on a day which is not a Business Day, such Interest Period shall be extended to the next succeeding Business Day (except that where the next succeeding Business Day falls in the next succeeding calendar month, then on the next preceding Business Day), (ii) no Interest Period shall extend beyond the Maturity Date and (iii) where an Interest Period begins on a day for which there is no numerically corresponding day in the calendar month in which the Interest Period is to end, such Interest Period shall end on the last Business Day of such calendar month.

"June Loan" shall mean the term loan made available by the Lender to the Borrower in the principal amount of Thirty Million Dollars ($30,000,000) on June 9, 2008, subject to the terms and conditions hereunder.

"June Note" shall mean the promissory note in substantially the form of Exhibit A attached hereto in the principal amount of the June Loan and dated June 9, 2008.

"Junior Subordinated Deferred Interest Debt Obligations" means subordinated deferrable interest debt obligations of the Borrower or one of its Subsidiaries.

"Lender" means Lloyds TSB Bank PLC, acting through its New York branch, together with its successors and assigns.

"Lender-Related Persons" means each of the Lender (including any successor Lender), together with its Affiliates, and the officers, directors, employees, representatives, agents, counsel and attorneys-in-fact of the Lender and its Affiliates.

"Lien" means any mortgage, pledge, hypothecation, assignment, deposit arrangement, security interest, encumbrance, lien (statutory or otherwise), preference, priority or charge of any kind (including any agreement to give any of the foregoing, any conditional sale or other title retention agreement, any financing or similar statement or notice filed under the Uniform Commercial Code as adopted and in effect in the relevant jurisdiction or other similar recording or notice statute, and any lease in the nature thereof).

"Loans" means, collectively, the April Loan and the June Loan, together in the total principal amount of One Hundred Ten Million Dollars (U.S. $110,000,000.00).

"Loan Documents" means this Loan Agreement, the Term Loan Notes and all other related agreements and documents issued or delivered hereunder or thereunder or pursuant hereto or thereto.

"Material Adverse Effect" means a material adverse effect on (a) the operations, assets, financial condition or business of the Borrower, (b) the ability of the Borrower to perform its obligations under this Loan Agreement and the other Loan Documents or (c) the validity or enforceability of this Loan Agreement, any of the other Loan Documents, or the rights and remedies of the Lender hereunder or thereunder, provided, that neither a downgrade in any Debt Rating nor the inability of the Borrower to place commercial paper shall, in and of itself, constitute a Material Adverse Effect.

"Maturity Date" means April 8, 2011, provided that if the Maturity Date as determined hereunder falls on a day that is not a Business Day, such Maturity Date shall be deemed to fall on the next preceding Business Day.

"Moody's" means Moody's Investors Service, Inc., or any successor or assignee of the business of such company in the business of rating securities.

"Multiemployer Plan" means at any time an employee pension benefit plan within the meaning of Section 4001(a)(3) of ERISA to which any member of the Controlled Group is then making or accruing an obligation to make contributions or has within the preceding five plan years made contributions, including for these purposes any Person which ceased to be a member of the Controlled Group during such five year period but only with respect to the period during which such Person was a member of the Controlled Group.

"Net Tangible Assets" means, as of any date, the total assets shown on the balance sheet of the Borrower and its Subsidiaries, determined on a consolidated basis in accordance with GAAP less (a) all current liabilities and minority interests and (b) goodwill and other identifiable intangibles.

"Notice of Borrowing" means the request by the Borrower for each of the April Loan and the June Loan (or any continuation thereof) in a form acceptable to the Lender.

"Off Balance Sheet Indebtedness" means any obligation of a Person that would be considered indebtedness for tax purposes but is not set forth on the balance sheet of such Person, including, but not limited to, (a) any synthetic lease, tax retention operating lease, off balance sheet loan or similar off balance sheet financing product of such Person, (b) the aggregate amount of uncollected accounts receivables of such Person subject at such time to a sale of receivables (or similar transaction) and (c) obligations of any partnership or joint venture that is recourse to such Person.

"Other Taxes" has the meaning set forth in Section 4.6(b).

"PBGC" means the Pension Benefit Guaranty Corporation established under ERISA, and any successor thereto.

"Pension Plan" means any "pension plan" as defined in Section 3(2) of ERISA which is maintained for the employees of the Borrower or any Subsidiary of the Borrower.

"Person" means any individual, partnership (general or limited), limited liability company, joint venture, firm, corporation, association, trust or other enterprise (whether or not incorporated), or any government or political subdivision or any agency, department or instrumentality thereof.

"Plan" means any single-employer plan as defined in Section 4001 of ERISA and to which ERISA applies, which is maintained, or at any time during the five calendar years preceding the date of this Loan Agreement was maintained, for employees of the Borrower, any Subsidiary of the Borrower or an ERISA Affiliate.

"Prime Rate" means the rate of interest per annum established from time to time by the Lender as its prime rate in effect at its office in New York City; each change in the Prime Rate shall be effective from and including the date such change is publicly announced as being effective.

"Regulation D, U or X" means Regulation D, U or X, respectively, of the Board of Governors of the Federal Reserve System as from time to time in effect and any successor to all or a portion thereof.

"Reportable Event" means a "reportable event" as defined in Section 4043 of ERISA with respect to which the notice requirements to the PBGC have not been waived.

"Responsible Officer" means, as to the Borrower, any of the Chief Executive Officer, Chief Financial Officer, Treasurer, Comptroller, Secretary, Assistant Treasurer or Assistant Secretary of the Borrower.

"S&P" means Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc., or any successor or assignee of the business of such division in the business of rating securities.

"Securitized Storm Bonds" means any bonds, debentures, notes, certificates of participation, certificates of beneficial interest, certificates of ownership or other evidences of indebtedness or ownership that are issued by the Borrower, any entity formed by the Borrower or any assignee pursuant to an order issued by the FPSC under legislation passed by the legislature of the State of Florida, including but not limited to §366.8260 of the Florida Statutes (2005), the proceeds of which are used directly or indirectly to recover, finance or refinance FPSC-approved storm-recovery costs, financing costs and/or costs to replenish the storm-recovery reserve to the level that existed before the applicable storm or storms or such other level as the FPSC may authorize in the applicable storm-recovery financing order, and which are secured by or payable from all rights and interests of the Borrower or its Subsidiaries or successor or assignee under the applicable storm-recovery financing order, including the right to impose, bill, collect and receive storm-recovery charges and to obtain periodic adjustments to such charges as provided in the applicable storm-recovery financing order.

"Senior Debt Rating" means the long-term senior unsecured, non-credit enhanced debt rating of the Borrower by S&P, Moody's or Fitch.

"Significant Subsidiary" means a Subsidiary of the Borrower which represents more than ten percent (10%) of the Borrower's assets on a consolidated basis.

"Subsidiary" means, as to any Person, (a) any corporation more than fifty percent (50%) of whose stock of any class or classes having by the terms thereof ordinary voting power to elect a majority of the directors of such corporation (irrespective of whether or not at the time, any class or classes of such corporation shall have or might have voting power by reason of the happening of any contingency) is at the time owned by such Person directly or indirectly through Subsidiaries and (b) any partnership, limited liability company, association, joint venture or other entity in which at the time such Person directly or indirectly through Subsidiaries has more than fifty percent (50%) equity interest.

"Substitute Rate" means, for each day, the per annum rate equal to the higher of the Prime Rate for such day or the sum of ½ of 1% plus the Federal Funds Effective Rate for such day.

"Taxes" has the meaning set forth in Section 4.6(a).

"Term Loan Notes" shall mean, collectively, the April Note and the June Note.

"Trust Preferred Obligations" means the subordinated, deferrable interest debt securities of the Borrower, and, without duplication, any related securities issued by a trust or other special purpose entity in connection therewith.

SECTION 1.2 Computation of Time Periods and Other Definitional Provisions. For purposes of computation of periods of time hereunder, the word "from" means "from and including" and the words "to" and "until" each mean "to but excluding." References in this Loan Agreement to "Sections", "Schedules" or "Exhibits" shall be to Sections, Schedules or Exhibits of or to this Loan Agreement unless otherwise specifically provided.

SECTION 1.3 Accounting Terms. Except as otherwise expressly provided herein, all accounting terms used herein shall be interpreted, and all financial statements and certificates and reports as to financial matters required to be delivered to the Lender hereunder shall be prepared, in accordance with GAAP applied on a consistent basis. All calculations made for the purposes of determining compliance with this Loan Agreement shall (except as otherwise expressly provided herein) be made by application of GAAP applied on a basis consistent with the most recent annual or quarterly financial statements delivered pursuant to Section 7.1 (or, prior to the delivery of the first financial statements pursuant to Section 7.1, consistent with the financial statements described in Section 5.1(e)), provided, however, if (a) the Borrower shall object to determining such compliance on such basis at the time of delivery of such financial statements due to any change in GAAP or the rules promulgated with respect thereto or (b) the Lender shall so object in writing within thirty (30) days after delivery of such financial statements, then such calculations shall be made on a basis consistent with the most recent financial statements delivered by the Borrower to the Lender as to which no such objection shall have been made.

SECTION 2: THE LOANS

SECTION 2.1 Term Loans. Subject to the terms and conditions set forth herein, the Lender agrees to make the April Loan and the June Loan to the Borrower on their respective Borrowing Dates, which shall be Business Days. Amounts borrowed and repaid or prepaid may not be reborrowed.

SECTION 2.2 Evidence of Obligations. (a) Lender Records. The date, amount, interest rate and duration of each Interest Period applicable to the Loans, and each payment made on account of the principal thereof, shall be recorded by the Lender on its books, provided that the failure of the Lender to make any such recordation shall not affect the obligations of the Borrower to make a payment when due of any amount owing hereunder or under the applicable Term Loan Note, and each such recordation shall be conclusive and binding absent manifest error.

(b) Term Loan Notes. The Loans shall be evidenced by the Term Loan Notes.

SECTION 3: PAYMENTS

SECTION 3.1 Payment in Full at Maturity. On the Maturity Date, the entire outstanding principal amount of the Loans, together with accrued but unpaid interest and all other sums owing under the Loan Documents shall be due and payable in full, unless accelerated sooner pursuant to Section 9.2.

SECTION 3.2 Interest. (a) Interest Rate. The principal amount of the Loans shall accrue interest at the Interbank Offered Rate plus 0.45%.

(b) Default Rate of Interest. Upon the occurrence, and during the continuance, of an Event of Default, the principal of and, to the extent permitted by law, interest on the Loans and any other amounts owing hereunder or under the other Loan Documents shall bear interest, payable on demand, at the Default Rate.

(c) Interest Payments. Accrued interest on Loans shall be due and payable in arrears on each Interest Payment Date.

SECTION 3.3 Prepayments. The Borrower shall have the right to prepay the Loans in whole or in part, without premium or penalty, at any time, provided, however, that (i) the Loans may only be prepaid on three (3) Business Days' prior written notice to the Lender; (ii) the Borrower shall pay all accrued interest and other amounts owing under the Loan Documents on the date of prepayment; and (iii) if any such prepayment is made on a date other than the last day of an Interest Period, the Borrower shall also pay any amounts owing pursuant to Section 4.5 on the date of prepayment.

SECTION 3.4 Place and Manner of Payments. All payments of principal, interest, fees, expenses and other amounts to be made by the Borrower under this Loan Agreement shall be made unconditionally and without deduction for any counterclaim, defense, recoupment or setoff. All such payments shall be received not later than 2:00 p.m. on the date when due in Dollars and in immediately available funds by the Lender at the account maintained by the Lender at its offices at Bank of America International, ABA #026-009-593, Account No. 655-010-1938, Account Name: Lloyds TSB Bank plc, New York, Reference: Gulf Power or any other designated account or location specified by the Lender. Whenever any payment hereunder shall be stated to be due on a day which is not a Business Day, the due date thereof shall be extended to the next succeeding Business Day (and interest shall accrue for the period of such extension), except that, if the extension would cause the payment to be made in the next following calendar month, then such payment shall instead be made on the next preceding Business Day.

SECTION 3.5 Computations of Interest. (a) All computations of interest and fees hereunder shall be made on the basis of the actual number of days elapsed over a year of three hundred sixty (360) days.

(b) It is the intent of the Lender and the Borrower to conform to and contract in strict compliance with applicable usury law from time to time in effect. All agreements between the Lender and the Borrower are hereby limited by the provisions of this Section 3.5(b) which shall override and control all such agreements, whether now existing or hereafter arising and whether written or oral. In no way, nor in any event or contingency (including but not limited to prepayment or acceleration of the maturity of the Loans), shall the interest taken, reserved, contracted for, charged or received under this Loan Agreement, under the Term Loan Notes or otherwise, exceed the maximum nonusurious amount permissible under applicable law. If, from any possible construction of any of the Loan Documents or any other document, interest would otherwise be payable in excess of the maximum nonusurious amount, any such construction shall be subject to the provisions of this Section 3.5(b) and the amount payable as interest hereunder shall be automatically reduced to the maximum nonusurious amount permitted under applicable law, without the necessity of execution of any amendment or new document. If the Lender shall ever receive anything of value which is characterized as interest on the Loans under applicable law and which would, apart from this Section 3.5(b), be in excess of the maximum lawful amount, an amount equal to the amount which would have been excessive interest shall, without penalty, be applied to the reduction of the principal amount owing on the Loans and not to the payment of interest, or refunded to the Borrower if and to the extent such amount which would have been excessive exceeds such unpaid principal amount of the Loans. The right to demand payment of the Loans or any other indebtedness evidenced by any of the Loan Documents does not include the right to receive any interest which has not otherwise accrued on the date of such demand, and the Lender does not intend to charge or receive any unearned interest in the event of such demand. All interest paid or agreed to be paid to the Lender with respect to the Loans shall, to the extent permitted by applicable law, be amortized, prorated, allocated and spread throughout the full stated term (including any renewal or extension) of the Loans so that the amount of interest on account of such indebtedness does not exceed the maximum nonusurious amount permitted by applicable law.

SECTION 4: ADDITIONAL PROVISIONS

SECTION 4.1 Unavailability. In the event that the Lender shall have determined in good faith (i) that Dollar deposits in the principal amount of the Loans are not generally available in the London Interbank Eurodollar market or (ii) that reasonable means do not exist for ascertaining the Eurodollar Rate, the Lender shall, as soon as practicable thereafter, give written notice of such determination to the Borrower, and thereupon the Loans shall bear interest at the Substitute Rate.

SECTION 4.2 Change in Legality. Notwithstanding any other provision herein, if any change in any law or regulation or in the interpretation thereof by any Governmental Authority charged with the administration or interpretation thereof shall make it unlawful for the Lender to make or maintain the Loans or to give effect to its obligations as contemplated hereby with respect to the Loans, then, by written notice to the Borrower, the

Lender may declare that the Loans, and continuations of it, will not thereafter be made by the Lender.

SECTION 4.3 Increased Costs. If at any time the Lender shall incur increased costs or reductions in the amounts received or receivable hereunder with respect to the making or the maintaining of the Loans because of any change since the date of this Loan Agreement in any applicable law, governmental rule, regulation, guideline or order (or in the interpretation or administration thereof and including the introduction of any new law or governmental rule, regulation, guideline or such order), including, without limitation, the imposition, modification or deemed applicability of any reserves, deposits or similar requirements (such as, for example, but not limited to, a change in official reserve requirements, but, in all events, excluding reserves required under Regulation D to the extent included in the computation of the Eurodollar Rate), then the Borrower shall pay to the Lender within fifteen (15) days after demand, which demand shall contain the basis and calculations supporting such demand, such additional amounts (in the form of an increased rate of, or a different method of calculating, interest or otherwise as the Lender may determine in its sole discretion) as may be required to compensate the Lender for such increased costs or reductions in amounts receivable hereunder. Each determination and calculation made by the Lender hereunder shall, absent manifest error, be binding and conclusive on the Borrower.

SECTION 4.4 Capital Adequacy. If, after the date hereof, the Lender has determined that the adoption or effectiveness of any applicable law, rule or regulation regarding capital adequacy, mandatory reserves, deposits or similar requirements (such as, for example, but not limited to, a change in official reserve requirements, but, in all events, excluding reserves required under Regulation D to the extent included in the computation of the Eurodollar Rate), or any change therein, or any change in the interpretation or administration thereof by any Governmental Authority, central bank or comparable agency charged with the interpretation or administration thereof, or compliance by the Lender with any request or directive regarding capital adequacy (whether or not having the force of law) of any such authority, central bank or comparable agency, has or would have the effect of reducing the rate of return on the Lender's (or its parent corporation's) capital or assets as a consequence of its obligations hereunder to a level below that which the Lender, or its parent corporation, could have achieved but for such adoption, effectiveness, change or compliance (taking into consideration the Lender's (or its parent corporation's) policies with respect to capital adequacy), then the Borrower shall pay to the Lender within fifteen (15) days after demand, which demand shall contain the basis and calculations supporting such demand, such additional amount or amounts as will compensate the Lender for such reduction. Each determination by any the Lender of amounts owing under this Section 4.4 shall, absent manifest error, be binding and conclusive on the Borrower.

SECTION 4.5 Compensation. The Borrower shall compensate the Lender, within fifteen (15) days after demand, which demand shall contain the basis and calculations supporting such demand, for all reasonable losses, expenses and liabilities (including, without limitation, any loss, expense or liability incurred by reason of the liquidation or reemployment of deposits or other funds required by the Lender to fund the Loans) which the Lender may sustain:

(a) if for any reason (other than a default by the Lender) the borrowing of the Loans does not occur on the Borrowing Date;

(b) if any repayment or prepayment of the Loans occurs on a date which is not the last day of an Interest Period applicable thereto, including, without limitation, in connection with any demand, acceleration, prepayment or otherwise (including any demand under this Section 4), unless at the time of such repayment or prepayment, the Loans bear interest at the Substitute Rate, in which case no such compensation from the Borrower to the Lender shall be paid; or

(c) if the Borrower fails to repay the Loans when required by the terms of this Loan Agreement.

Calculation of all amounts payable to the Lender under this Section 4.5 shall be made as though the Lender has actually funded the Loans through the purchase of a Eurodollar deposit bearing interest at the Eurodollar Rate in an amount equal to the amount of the Loans, having a maturity comparable to the relevant Interest Period and through the transfer of such Eurodollar deposit from an offshore office of the Lender to a domestic office of the Lender in the United States of America, provided, however, that the Lender may fund the Loans in any manner it sees fit and the foregoing assumption shall be utilized only for the calculation of amounts payable under this Section 4.5. Each determination and calculation hereunder shall be in good faith and shall be conclusive absent manifest error.

SECTION 4.6 Taxes. (a) Tax Liabilities Imposed on the Lender. Any and all payments by the Borrower hereunder or under any of the Loan Documents shall be made, in accordance with the terms hereof and thereof, free and clear of and without deduction for any and all present or future taxes, levies, imposts, deductions, charges or withholdings, and all liabilities with respect thereto, excluding taxes measured by net income and franchise taxes imposed on the Lender by the jurisdiction under the laws of which the Lender is organized or transacting business or any political subdivision thereof (all such nonexcluded taxes, being hereinafter referred to as "Taxes"). If the Borrower shall be required by law to deduct any Taxes from or in respect of any sum payable hereunder to the Lender, (i) the sum payable shall be increased as may be necessary so that after making all required deductions (including deductions applicable to additional sums payable under this Section 4.6) the Lender receives an amount equal to the sum it would have received had no such deductions been made, (ii) the Borrower shall make such deductions, (iii) the Borrower shall pay the full amount deducted to the relevant Governmental Authority in accordance with applicable law, and (iv) the Borrower shall deliver to the Lender evidence of such payment to the relevant Governmental Authority.

(b) Other Taxes. In addition, the Borrower agrees to pay, upon written notice from the Lender and prior to the date when penalties attach thereto, all present or future stamp or documentary taxes or any other excise or property taxes, charges or similar levies of the United States or any state or political subdivision thereof or any applicable foreign jurisdiction that arise

from any payment made hereunder or from the execution, delivery or registration of, or otherwise with respect to, this Loan Agreement (collectively, the "Other Taxes").

(c) Refunds. If the Lender shall become aware that it is entitled to claim a refund (or a refund in the form of a credit) (each, a "Refund") from a Governmental Authority (as a result of any error in the amount of Taxes or Other Taxes paid to such Governmental Authority or otherwise) of Taxes or Other Taxes which the Borrower has paid, or with respect to which the Borrower has paid additional amounts, pursuant to this Section 4.6, it shall promptly notify the Borrower in writing of the availability of such Refund and shall, within thirty (30) days after receipt of written notice by the Borrower, make a claim to such Governmental Authority for such Refund at the Borrower's expense if, in the judgment of the Lender, the making of such claim will not be otherwise disadvantageous to it, provided that nothing in this Section 4.6(c) shall be construed to require the Lender to institute any administrative proceeding (other than the filing of a claim for any such Refund) or judicial proceeding to obtain such Refund.

If the Lender determines that it has received a Refund from a Governmental Authority (as a result of any error in the amount of Taxes or Other Taxes paid to such Governmental Authority or otherwise) of any Taxes or Other Taxes which have been paid by the Borrower, or with respect to which the Borrower has paid additional amounts pursuant to this Section 4.6, it shall promptly pay to the Borrower the amount so received (but only to the extent of payments made, or additional amounts paid, by the Borrower under this Section 4.6 with respect to Taxes or Other Taxes giving rise to such Refund), net of all reasonable out of pocket expenses (including the net amount of taxes, if any, imposed on the Lender with respect to such Refund) by the Lender, and without interest (other than interest paid by the relevant Governmental Authority with respect to such Refund), provided, however, that the Borrower, upon the request of the Lender, agrees to repay the amount paid over to the Borrower (plus penalties, interest or other charges) to the Lender in the event the Lender is required to repay such Refund to such Governmental Authority. Nothing contained in this Section 4.6(c) shall require the Lender to make available any of its tax returns (or any other information that it deems to be confidential or proprietary).

SECTION 4.7 Mitigation; Mandatory Assignment. The Lender shall use reasonable efforts to avoid or mitigate any increased cost or suspension of the availability of an interest rate under Sections 4.1 through 4.4 above to the greatest extent practicable unless, in the opinion of the Lender, such efforts would be likely to have an adverse effect upon it.

SECTION 5: CONDITIONS PRECEDENT

SECTION 5.1 Borrowing Conditions. The obligation of the Lender to make a Loan is subject to satisfaction of the following conditions on or prior to the applicable Borrowing Date (in form and substance acceptable to the Lender):

(a) Executed Loan Documents. Receipt by the Lender of duly executed copies of (i) this Loan Agreement and (ii) the applicable Term Loan Note.

(b) Officer's Certificate. Receipt by the Lender of a certificate of an officer of the Borrower stating that, as of the applicable Borrowing Date, (i) there exists no Default or Event of Default and (ii) all representations and warranties contained herein and in the other Loan Documents are true and correct in all material respects.

(c) Opinion of Counsel. Receipt by the Lender of an opinion, or opinions, satisfactory to the Lender, addressed to the Lender from legal counsel to the Borrower.

(d) Corporate Documents. Receipt by the Lender of the following:

(i) Charter Documents. A copy of the Borrower's articles of incorporation, as amended, certified by the Secretary of State of Florida.

(ii) Bylaws. A copy of the bylaws of the Borrower certified by the secretary or an assistant secretary of the Borrower to be true and correct as of the applicable Borrowing Date.

(iii) Resolutions. Copies of resolutions of the Board of Directors of the Borrower approving and adopting the Loan Documents and the transactions contemplated therein and authorizing execution and delivery thereof, certified by the secretary or an assistant secretary of the Borrower to be true and correct and in force and effect as of the applicable Borrowing Date.

(iv) Good Standing. Copies of certificates of good standing, existence or its equivalent with respect to the Borrower certified as of a recent date by the appropriate Governmental Authorities of the state or other jurisdiction of its incorporation and each other jurisdiction in which the failure to so qualify to be in good standing would have a Material Adverse Effect.

(v) Incumbency. An incumbency certificate of the Borrower, certified by the secretary or an assistant secretary of the Borrower to be true and correct as of the applicable Borrowing Date.

(e) Financial Statements. Receipt by the Lender of the consolidated audited financial statements of the Borrower dated as of December 31, 2007, including balance sheets and income and cash flow statements, in each case audited by independent public accountants of recognized standing and prepared in accordance with GAAP.

(f) Fees and Expenses. Payment by the Borrower of all fees and expenses owed by it to the Lender.

(g) Material Adverse Effect. No event or condition shall have occurred since the date of the financial statements delivered pursuant to Section 5.1(e) above that has had or would be likely to have a Material Adverse Effect.

(h) Litigation. Except as disclosed in the Borrower's Annual Report on Form 10-K for the year ended December 31, 2007 and in any Current Report on Form 8-K filed by the Borrower between December 31, 2007 and the applicable Borrowing Date, there shall not exist any action, suit, investigation or proceeding, nor shall any action, suit or investigation be pending or, to the knowledge of the Borrower, threatened in any court or before any arbitrator or Governmental Authority that materially adversely affects the Borrower or any transaction contemplated hereby or the ability of the Borrower to perform its obligations under the Loan Documents.

(i) Other. Receipt by the Lender of such other documents, instruments, agreements or information as reasonably requested by the Lender.

(j) Request. The Borrower shall have timely delivered a duly executed and completed Notice of Borrowing in conformance with all the terms and conditions of this Loan Agreement; such Notice of Borrowing to be received by the Bank on the third Business Day prior to the date on which the relevant Loan is required to be made;

(k) Representations and Warranties. The representations and warranties made by the Borrower in the Loan Documents are true and correct in all material respects at and as if made as of the applicable Borrowing Date; and

(l) No Default. On the applicable Borrowing Date, no Default or Event of Default has occurred and is continuing or would be caused by making the applicable Loan, including, without limitation, the restrictions on the use of proceeds set forth in Section 7.9.

The delivery of a Notice of Borrowing shall constitute a representation and warranty by the Borrower of the correctness of the matters specified in Sections 5.1(k) and 5.1(l) above.

SECTION 6: REPRESENTATIONS AND WARRANTIES

The Borrower hereby represents and warrants to the Lender that:

SECTION 6.1 Organization and Good Standing. The Borrower and each Significant Subsidiary (a) is a corporation duly incorporated, validly existing and in good standing under the laws of the jurisdiction of its incorporation, (b) is duly qualified and in good standing as a foreign corporation authorized to do business in every jurisdiction where the failure to so qualify would have a Material Adverse Effect and (c) has the requisite corporate power and authority to own its properties and to carry on its business as now conducted and as proposed to be conducted.

SECTION 6.2 Due Authorization. The Borrower (a) has the requisite corporate power and authority to execute, deliver and perform this Loan Agreement and the other Loan Documents and to incur the obligations herein and therein provided for and (b) is duly authorized, and has been authorized by all necessary corporate action, to execute, deliver and perform this Loan Agreement and the other Loan Documents.

SECTION 6.3 No Conflicts. Neither the execution and delivery of the Loan Documents, nor the consummation of the transactions contemplated therein, nor performance of and compliance with the terms and provisions thereof by the Borrower will (a) violate or conflict with any provision of its certificate or articles of incorporation or bylaws, (b) violate, contravene or materially conflict with any law, regulation (including without limitation, Regulation D, U or X), order, writ, judgment, injunction, decree or permit applicable to it, (c) violate, contravene or materially conflict with contractual provisions of, or cause an event of default under, any indenture, loan agreement, mortgage, deed of trust, contract or other agreement or instrument to which it is a party or by which it may be bound, the violation of which could have a Material Adverse Effect or (d) result in or require the creation of any Lien upon or with respect to its properties.

SECTION 6.4 Consents. No consent, approval, authorization or order of, or filing, registration or qualification with, any court or Governmental Authority or third party is required in connection with the execution, delivery or performance of this Loan Agreement or any of the other Loan Documents that has not been obtained.

SECTION 6.5 Enforceable Obligations. This Loan Agreement and the other Loan Documents have been duly executed and delivered by the Borrower and constitute legal, valid and binding obligations of the Borrower enforceable against the Borrower in accordance with their respective terms, except as may be limited by bankruptcy or insolvency laws or similar laws affecting creditors' rights generally or by general equitable principles.

SECTION 6.6 Financial Condition. The financial statements provided to the Lender as described in Section 5.1(e): (a) fairly present the financial condition and operations of the Borrower as of the date thereof and (b) were prepared in accordance with GAAP.

SECTION 6.7 No Default. No Default or Event of Default presently exists.

SECTION 6.8 Indebtedness and Off Balance Sheet Indebtedness. As of the Closing Date, the Borrower and its Subsidiaries have no Indebtedness except as disclosed in the financial statements referenced in Section 5.1(e) and as otherwise incurred in the ordinary course. Set forth on the Borrower's Annual Report on Form 10 K for the year ended December 31, 2007 is a specific description of all material Off Balance Sheet Indebtedness of the Borrower and its Subsidiaries as of the periods covered thereby.

SECTION 6.9 Litigation. Except as disclosed in the Borrower's Annual Report on Form 10-K for the year ended December 31, 2007 and in any Current Report on Form 8-K filed by the Borrower between December 31, 2007 and the Closing Date, there are no

actions, suits or legal, equitable, arbitration or administrative proceedings, pending or, to the knowledge of the Borrower, threatened against the Borrower or a Significant Subsidiary, in which there is a reasonable possibility of an adverse decision which has had or would be reasonably expected to have a Material Adverse Effect.

SECTION 6.10 Material Agreements. The Borrower is not in default in any respect under any contract, lease, loan agreement, indenture, mortgage, security agreement or other agreement or obligation to which it is a party or by which any of its properties is bound which default has had or would be reasonably expected to have a Material Adverse Effect.

SECTION 6.11 Taxes. The Borrower has filed, or caused to be filed, all material tax returns (federal, state, local and foreign) required to be filed and paid all amounts of taxes shown thereon to be due (including interest and penalties) and has paid all other taxes, fees, assessments and other governmental charges (including mortgage recording taxes, documentary stamp taxes and intangibles taxes) owing by it, except for such taxes (a) which are not yet delinquent or (b) that are being contested in good faith and by proper proceedings, and against which adequate reserves are being maintained in accordance with GAAP. The Borrower is not aware of any proposed material tax assessments against it.

SECTION 6.12 Compliance with Law. The Borrower is in compliance with all laws, rules, regulations, orders and decrees applicable to it, or to its properties, unless such failure to comply would not have a Material Adverse Effect.

SECTION 6.13 ERISA. (a) No Reportable Event has occurred and is continuing with respect to any Plan; (b) no Plan has an accumulated funding deficiency determined under Section 412 of the Code; (c) no proceedings have been instituted, or, to the knowledge of the Borrower, planned to terminate any Plan; (d) neither the Borrower, nor any member of a Controlled Group, nor any duly-appointed administrator of a Plan has instituted or intends to institute proceedings to withdraw from any Multiemployer Plan; and (e) each Plan has been maintained and funded in all material respects with its terms and with the provisions of ERISA applicable thereto.

SECTION 6.14 Use of Proceeds; Margin Stock. The proceeds of the Loans (a) will be used solely for the purposes specified in Section 7.9 and (b) will not be used (i) in a manner that would cause a violation of Regulation U or Regulation X or (ii) for the acquisition of another Person unless the board of directors (or other comparable governing body) or stockholders, as appropriate, of such Person has approved such acquisition.

SECTION 6.15 Government Regulation. The issuance of the Term Loan Notes by the Borrower hereunder, the incurrence of the indebtedness contemplated by this Loan Agreement and the borrowing and repayment of the Loans hereunder requires no authorization or approval of any Governmental Authority other than such authorizations and approvals that already have been obtained. The Borrower is not an "investment company" registered or

required to be registered under the Investment Company Act of 1940, as amended, or controlled by such a company.

SECTION 6.16 Solvency. The Borrower is solvent. For purposes of the preceding sentence, "solvent" means (a) the fair saleable value (on a going concern basis) of the Borrower's assets exceed its liabilities, contingent or otherwise, fairly valued, (b) the Borrower will be able to pay its debts as they become due and (c) upon paying its debts as they become due, the Borrower will not be left with unreasonably small capital as is necessary to satisfy all of its current and reasonably anticipated obligations.

SECTION 7: AFFIRMATIVE COVENANTS

The Borrower hereby covenants and agrees that so long as this Loan Agreement is in effect and until the Loans, together with interest, fees, costs, expenses and other obligations hereunder, have been paid in full:

SECTION 7.1 Information Covenants. The Borrower will furnish, or cause to be furnished, to the Lender:

(a) Annual Financial Statements. As soon as available, and in any event within one hundred twenty (120) days after the close of each fiscal year of the Borrower, a consolidated balance sheet and income statement of the Borrower and its Subsidiaries as of the end of such fiscal year, together with related statements of operations and retained earnings and of cash flows for such fiscal year, setting forth in comparative form figures for the preceding fiscal year, all such financial information described above to be in reasonable form and detail and audited by registered independent public accounting firm of recognized national standing reasonably acceptable to the Lender and whose opinion shall be to the effect that such financial statements have been prepared in accordance with GAAP (except for changes with which such accountants concur) and shall not be limited as to the scope of the audit or qualified as to going concern.

(b) Quarterly Financial Statements. As soon as available, and in any event within fifty-five (55) days after the close of each fiscal quarter of the Borrower (other than the fourth fiscal quarter) a consolidated balance sheet and income statement of the Borrower and its Subsidiaries as of the end of such fiscal quarter, together with related statements of operations and retained earnings and of cash flows for such fiscal quarter in each case setting forth in comparative form figures for the corresponding period of the preceding fiscal year, all such financial information described above to be in reasonable form and detail and reasonably acceptable to the Lender, and accompanied by a certificate of the chief financial officer of the Borrower to the effect that such quarterly financial statements fairly present in all material respects the financial condition of the Borrower and its Subsidiaries and have been prepared in accordance with GAAP, subject to changes resulting from audit and normal year end audit adjustments.

(c) Officer's Certificate. At the time of delivery of the financial statements provided for in Sections 7.1(a) and 7.1(b) above, a certificate of the chief financial officer of the Borrower, substantially in the form of Exhibit B, (i) demonstrating compliance with the financial covenant contained in Section 7.11 by calculation thereof as of the end of each such fiscal period and (ii) stating that no Default or Event of Default exists, or if any Default or Event of Default does exist, specifying the nature and extent thereof and what action the Borrower proposes to take with respect thereto.

(d) Reports. Promptly upon transmission or receipt thereof, copies of any filings and registrations with, and reports to or from, the Securities and Exchange Commission, or any successor agency, and copies of all financial statements, proxy statements, notices and reports as the Borrower shall send to its shareholders.

(e) Notices. Upon the Borrower obtaining knowledge thereof, the Borrower will give written notice to the Lender immediately of (i) the occurrence of an event or condition consisting of a Default or Event of Default, specifying the nature and existence thereof and what action the Borrower proposes to take with respect thereto, and (ii) the occurrence of any of the following with respect to the Borrower: (A) the pendency or commencement of any litigation, arbitral or governmental proceeding against the Borrower which, if adversely determined, is likely to have a Material Adverse Effect, (B) the institution of any proceedings against the Borrower with respect to, or the receipt of notice by the Borrower of potential liability or responsibility for, violation or alleged violation of any federal, state or local law, rule or regulation, the violation of which would likely have a Material Adverse Effect or (C) any notice or determination concerning the imposition of any withdrawal liability by a Multiemployer Plan against the Borrower or any of its ERISA Affiliates, the determination that a Multiemployer Plan is, or is expected to be, in reorganization within the meaning of Title IV of ERISA or the termination of any Plan.

(f) Other Information. With reasonable promptness upon any such request, such other information regarding the business, properties or financial condition of the Borrower as the Lender may reasonably request.

(g) Electronic Delivery. The Borrower's obligation to provide financial statements or other information to the Lender pursuant to this Section 7.1 shall be deemed satisfied if and to the extent such financial statements or other information shall be available to the Lender via the Internet or e-mail.

SECTION 7.2 Preservation of Existence and Franchises. The Borrower will, except as permitted by Section 8.2, do all things necessary to preserve and keep in full force and effect its existence, rights, franchises and authority.

SECTION 7.3 Books and Records. The Borrower will keep complete and accurate books and records of its transactions in accordance with good accounting practices on the basis of GAAP (including the establishment and maintenance of appropriate reserves).

SECTION 7.4 Compliance with Law. The Borrower will comply with all laws, rules, regulations and orders, and all restrictions imposed by all Governmental Authorities, applicable to it and its property if noncompliance with any such law, rule, regulation, order or restriction would be reasonably expected to have a Material Adverse Effect.

SECTION 7.5 Payment of Taxes. The Borrower will pay and discharge all taxes, assessments and governmental charges or levies imposed upon it, or upon its income or profits, or upon any of its properties, before they shall become delinquent, provided, however, that the Borrower shall not be required to pay any such tax, assessment, charge, levy or claim which is being contested in good faith by appropriate proceedings and as to which adequate reserves therefor have been established in accordance with GAAP.

SECTION 7.6 Insurance. The Borrower will at all times maintain in full force and effect insurance (including worker's compensation insurance, liability insurance, casualty insurance and business interruption insurance) in such amounts, covering such risks and liabilities and with such deductibles or self insurance retentions as are in accordance with normal industry practice.

SECTION 7.7 Performance of Obligations. The Borrower will perform in all material respects all of its obligations under the terms of all material agreements, indentures, mortgages, security agreements or other material debt instruments to which it is a party or by which it is bound.

SECTION 7.8 ERISA. The Borrower and each ERISA Affiliate will (a) at all times make prompt payment of all contributions (i) required under all Pension Plans and (ii) required to meet the minimum funding standard set forth in ERISA with respect to each Plan; (b) promptly upon request, furnish the Lender copies of each annual report/return (Form 5500 Series), as well as all schedules and attachments required to be filed with the Department of Labor and/or the Internal Revenue Service pursuant to ERISA, in connection with each of its Pension Plans for each Plan Year (as defined in ERISA); (c) notify the Lender immediately of any fact, including, but not limited to, any Reportable Event arising in connection with any of its Plans, which might constitute grounds for termination thereof by the PBGC or for the appointment by the appropriate United States District Court of a trustee to administer such Plan, together with a statement, if requested by the Lender, as to the reason therefor and the action, if any, proposed to be taken in respect thereof; and (d) furnish to the Lender, upon its request, such additional information concerning any of its Plans as may be reasonably requested. The Borrower will not nor will it permit any ERISA Affiliate to (i) terminate a Plan if any such termination would have a Material Adverse Effect or (ii) cause or permit to exist any Reportable Event under ERISA or other event or condition which presents a material risk of termination at the request of the PBGC if such termination would have a Material Adverse Effect.

SECTION 7.9 Use of Proceeds. The proceeds of the Loans shall be used for general corporate purposes, provided that the proceeds of the Loans may not be used to acquire

another Person unless the board of directors (or other comparable body) or stockholders, as appropriate, of such Person has approved such acquisition.

SECTION 7.10 Audits/Inspections. Upon reasonable notice and during normal business hours, the Borrower will permit representatives appointed by the Lender, including, without limitation, independent accountants, agents, attorneys and appraisers to visit and inspect the Borrower's property, including its books and records, its accounts receivable and inventory, the Borrower's facilities and its other business assets, and to make photocopies or photographs thereof and to write down and record any information such representative obtains and shall permit the Lender or its representatives to investigate and verify the accuracy of information provided to the Lender and to discuss all such matters with the officers, employees and representatives of the Borrower.

SECTION 7.11 Indebtedness to Capitalization. The ratio of (a) Indebtedness of the Borrower to (b) Capitalization shall at all times be less than or equal to sixty-five hundredths to one (.65 to 1.0).

SECTION 8: NEGATIVE COVENANTS

The Borrower hereby covenants and agrees that so long as this Loan Agreement is in effect and until the Loans, together with interest, fees, costs, expenses and other obligations hereunder, have been paid in full:

SECTION 8.1 Nature of Business. The Borrower will not alter the character of its business from that conducted as of the Closing Date.

SECTION 8.2 Consolidation and Merger. The Borrower will not enter into any transaction of merger or consolidation or liquidate, wind up or dissolve itself (or suffer any liquidation or dissolution), provided that notwithstanding the foregoing provisions of this Section 8.2, the following actions may be taken if after giving effect thereto no Default or Event of Default exists:

(a) a Subsidiary of the Borrower may be merged or consolidated with or into the Borrower, provided that the Borrower shall be the continuing or surviving corporation; and

(b) the Borrower may merge or consolidate with any other Person (other than one of its Subsidiaries) if either (i) the Borrower shall be the continuing or surviving corporation or (ii) the Borrower shall not be the continuing or surviving corporation and the corporation so continuing or surviving (A) is a corporation organized and duly existing under the law of any state of the United States, (B) has (1) a long-term, senior, unsecured, non-credit enhanced debt rating of BBB- or better from S&P and Baa3 or better from Moody's or (2) a commercial paper rating of A-2 or better from S&P and P-2 or better from Moody's and (C) executes and delivers to the Lender an instrument in form satisfactory to the Lender pursuant to which it expressly assumes the Loans and all of the other obligations of the Borrower under the Loan Documents

and procures for the Lender an opinion in form satisfactory to the Lender and from counsel satisfactory to the Lender in respect of the due authorization, execution, delivery and enforceability of such instrument and covering such other matters as the Lender may reasonably request, provided that prior to any such merger or consolidation, the Borrower shall have delivered to the Lender a certificate demonstrating that, upon giving effect to such merger or consolidation on a pro forma basis, the Borrower will be in compliance with Section 7.11.

SECTION 8.3 Sale or Lease of Assets. The Borrower will not convey, sell, lease, transfer or otherwise dispose of in one transaction or a series of transactions, all or substantially all of its business or assets whether now owned or hereafter acquired.

SECTION 8.4 Transactions with Affiliates. Except as otherwise required by law, the Borrower will not enter into any transaction or series of transactions, whether or not in the ordinary course of business, with any of its Affiliates other than on terms and conditions substantially as favorable as would be obtainable in a comparable arm's length transaction with a Person other than an Affiliate.

SECTION 8.5 Fiscal Year. The Borrower will not change its fiscal year (a) without prior written notification to the Lender and (b) if such change would materially affect the Lender's ability to read and interpret the financial statements delivered pursuant to Section 7.1 or calculate the financial covenant in Section 7.11.

SECTION 8.6 Liens. The Borrower will not contract, create, incur, assume or permit to exist any Lien with respect to any of its property or assets of any kind (whether real or personal, tangible or intangible), whether now owned or hereafter acquired, securing any Indebtedness (unless the Loans hereunder are equally and ratably secured with such other Indebtedness) other than the following: (a) Liens securing Borrower Obligations, (b) Liens for taxes not yet due or Liens for taxes being contested in good faith by appropriate proceedings for which adequate reserves determined in accordance with GAAP have been established (and as to which the property subject to any such Lien is not yet subject to foreclosure, sale or loss on account thereof), (c) Liens in respect of property imposed by law arising in the ordinary course of business such as materialmen's, mechanics', warehousemen's, carrier's, landlords' and other nonconsensual statutory Liens which are not yet due and payable, which have been in existence less than 90 days or which are being contested in good faith by appropriate proceedings for which adequate reserves determined in accordance with GAAP have been established (and as to which the property subject to any such Lien is not yet subject to foreclosure, sale or loss on account thereof), (d) pledges or deposits made in the ordinary course of business to secure payment of worker's compensation insurance, unemployment insurance, pensions or social security programs, (e) Liens arising from good faith deposits in connection with or to secure performance of tenders, bids, leases, government contracts, performance and return-of-money bonds and other similar obligations incurred in the ordinary course of business (other than obligations in respect of the payment of borrowed money), (f) Liens arising from good faith deposits in connection with or to secure performance of statutory obligations and surety and appeal bonds, (g) easements, rights-of-way, restrictions (including zoning restrictions), minor

defects or irregularities in title and other similar charges or encumbrances not, in any material respect, impairing the use of the encumbered property for its intended purposes, (h) judgment Liens that would not constitute an Event of Default, (i) Liens arising by virtue of any statutory or common law provision relating to banker's liens, rights of setoff or similar rights as to deposit accounts or other funds maintained with a creditor depository institution, (j) any Lien created or arising over any property which is acquired, constructed or created by the Borrower, but only if (i) such Lien secures only principal amounts (not exceeding the cost of such acquisition, construction or creation) raised for the purposes of such acquisition, construction or creation, together with any costs, expenses, interest and fees incurred in relation thereto or a guarantee given in respect thereof, (ii) such Lien is created or arises on or before 180 days after the completion of such acquisition, construction or creation and (iii) such Lien is confined solely to the property so acquired, constructed or created and any improvements thereto, (k) any liens arising in connection with the issuance of Securitized Storm Bonds, (l) any Lien on any property or assets acquired from a corporation or other entity which is merged with or into the Borrower in accordance with Section 8.2, and is not created in anticipation of any such transaction (unless such Lien is created to secure or provide for the payment of any part of the purchase price of such corporation or other entity), (m) any Lien on any property or assets existing at the time of acquisition of such property or assets by the Borrower and which is not created in anticipation of such acquisition (unless such Lien was created to secure or provide for the payment of any part of the purchase price of such property or assets), (n) any extension, renewal or replacement (or successive extensions, renewals or replacements), as a whole or in part, of any Liens referred to in the foregoing clauses (a) through (m), for amounts not exceeding the principal amount of the Indebtedness secured by the Lien so extended, renewed or replaced, provided that such extension, renewal or replacement Lien is limited to all or a part of the same property or assets that were covered by the Lien extended, renewed or replaced (plus improvements on such property or assets) and (o) Liens on property, in addition to those otherwise permitted by clauses (a) through (n) above, securing, directly or indirectly, Indebtedness which does not exceed, in the aggregate at any one time outstanding, fifteen percent (15%) of Net Tangible Assets.

SECTION 9: EVENTS OF DEFAULT

SECTION 9.1 Events of Default. An Event of Default shall exist upon the occurrence of any of the following specified events (each an "Event of Default"):

(a) Payment. The Borrower shall:

(i) default in the payment when due of any principal of the Loans;

(ii) default, and such default shall continue for five (5) or more Business Days, in the payment when due of any interest on the Loans or of any fees, costs, expenses or other amounts owing hereunder, under any of the other Loan Documents or in connection herewith.

(b) Representations. Any representation, warranty or statement made or deemed to be made by the Borrower herein, in any of the other Loan Documents, or in any statement or certificate delivered or required to be delivered pursuant hereto or thereto shall prove untrue in any material respect on the date as of which it was made or deemed to have been made.

(c) Covenants. The Borrower shall:

(i) default in the due performance or observance of any term, covenant or agreement contained in Sections 7.2, 7.3, 7.4, 7.9, 7.11 or 8.1 through 8.6, inclusive; or

(ii) default in the due performance or observance by it of any term, covenant or agreement contained in Section 7.1(a), 7.1(b), 7.1(c) or 7.1(e) and such default shall continue unremedied for a period of ten (10) Business Days after the earlier of an officer of the Borrower becoming aware of such default or written notice thereof given by the Lender; or

(iii) default in the due performance or observance by it of any term, covenant or agreement (other than those referred to in Sections 9.1(a), 9.1(b), 9.1(c)(i) or 9.1(c)(ii)) contained in this Loan Agreement or any other Loan Document and such default shall continue unremedied for a period of at least thirty (30) days after the earlier of an officer of the Borrower becoming aware of such default or written notice thereof given by the Lender.

(d) Loan Documents. Any Loan Document shall fail to be in full force and effect or to give the Lender the rights, powers and privileges purported to be created thereby.

(e) Bankruptcy, etc. The occurrence of any of the following with respect to the Borrower or a Significant Subsidiary: (i) a court or governmental agency having jurisdiction in the premises shall enter a decree or order for relief in respect of the Borrower or a Significant Subsidiary in an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or appoint a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of the Borrower or a Significant Subsidiary or for any substantial part of its property or ordering the winding up or liquidation of its affairs; or (ii) an involuntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect is commenced against the Borrower or a Significant Subsidiary and such petition remains unstayed and in effect for a period of sixty (60) consecutive days; or (iii) the Borrower or a Significant Subsidiary shall commence a voluntary case under any applicable bankruptcy, insolvency or other similar law now or hereafter in effect, or consent to the entry of an order for relief in an involuntary case under any such law, or consent to the appointment or taking possession by a receiver, liquidator, assignee, custodian, trustee, sequestrator or similar official of such Person or any substantial part of its property or make any general assignment for the benefit of creditors; or (iv) the Borrower or a Significant Subsidiary shall admit in writing its inability to pay its debts generally as they become due or any action shall be taken by such Person in furtherance of any of the aforesaid purposes.

(f) Defaults under Other Agreements. With respect to any Indebtedness (other than the Indebtedness under this Loan Agreement) of the Borrower or a Significant Subsidiary in a principal amount in excess of $25,000,000, (i) the Borrower or such Significant Subsidiary shall (A) default in any payment (interest or principal) (beyond the applicable grace period with respect thereto, if any) with respect to any such Indebtedness, or (B) default (after giving effect to any applicable grace period) in the observance or performance of any covenant or agreement relating to such Indebtedness or contained in any instrument or agreement evidencing, securing or relating thereto, or any other event or condition shall occur or condition exist, the effect of which default or other event or condition is to cause, or permit, the holder or holders of such Indebtedness (or trustee or agent on behalf of such holders) to cause any such Indebtedness to become due prior to its stated maturity; or (ii) any such Indebtedness shall be declared due and payable, or required to be prepaid other than by a regularly scheduled required prepayment, prior to the stated maturity thereof; or (iii) any such Indebtedness matures and remains unpaid.

(g) Judgments. One or more judgments, orders or decrees shall be entered against the Borrower or a Significant Subsidiary involving a liability of $25,000,000 or more, in the aggregate, (to the extent not paid or covered by insurance provided by a carrier who has acknowledged coverage) and such judgments, orders or decrees shall continue unsatisfied, undischarged and unstayed for a period ending on the first to occur of (i) the last day on which such judgment, order or decree becomes final and unappealable and, where applicable, with the status of a judicial lien or (ii) thirty (30) days.

(h) ERISA. (i) The Borrower, or any member of the Controlled Group, shall fail to pay when due an amount or amounts aggregating in excess of $100,000,000 which it shall have become liable to pay under Title IV of ERISA; or (ii) notice of intent to terminate a Plan or Plans which in the aggregate have unfunded liabilities in excess of $100,000,000 (individually and collectively, a "Material Plan") shall be filed under Title IV of ERISA by the Borrower or any member of the Controlled Group, any plan administrator or any combination of the foregoing; or (iii) the PBGC shall institute proceedings under Title IV of ERISA to terminate, to impose liability (other than for premiums under Section 4007 of ERISA) in respect of, or to cause a trustee to be appointed to administer any Material Plan; or (iv) a condition shall exist by reason of which the PBGC would be entitled to obtain a decree adjudicating that any Material Plan must be terminated; or (v) there shall occur a complete or partial withdrawal from, or a default, within the meaning of Section 4219(c)(5) of ERISA, with respect to, one or more Multiemployer Plans which could cause one or more members of the Controlled Group to incur a current payment obligation in excess of $100,000,000.

(i) Change of Control. The occurrence of any Change of Control.

SECTION 9.2 Acceleration; Remedies. Upon the occurrence of an Event of Default, and at any time thereafter unless and until such Event of Default has been waived by the Lender or cured to the satisfaction of the Lender, the Lender may, by written notice to the

Borrower take any of the following actions without prejudice to the rights of the Lender to enforce its claims against the Borrower, except as otherwise specifically provided for herein:

(a) Acceleration of the Loans. Declare the unpaid principal of and any accrued interest in respect of the Loans and any and all other indebtedness or obligations of any and every kind owing by the Borrower to the Lender hereunder to be due whereupon the same shall be immediately due and payable without presentment, demand, protest or other notice of any kind, all of which are hereby waived by the Borrower.

(b) Enforcement of Rights. Enforce any and all rights and interests created and existing under the Loan Documents, including, without limitation, all rights of set-off.

Notwithstanding the foregoing, if an Event of Default specified in Section 9.1(e) shall occur, then the Loans, all accrued interest in respect thereof, all accrued and unpaid fees and other indebtedness or obligations owing to the Lender hereunder shall immediately become due and payable.

SECTION 10: MISCELLANEOUS

SECTION 10.1 Notices and other Communications; Facsimile Copies. Except as otherwise expressly provided herein, all notices and other communications shall have been duly given and shall be effective at the earliest of the following: (a) when hand delivered, (b) when transmitted via telecopy (or other facsimile device) or electronic mail, (c) the Business Day following the day on which the same has been delivered prepaid to a reputable national overnight air courier service, or (d) the third Business Day following the day on which the same is sent by certified or registered mail, postage prepaid, in each case to the respective parties at the address or telecopy numbers set forth on Schedule 10.1, or at such other address as such party may specify by written notice to the other parties hereto. Notwithstanding the foregoing, a Notice of Borrowing or notice of payment or prepayment may not be given by electronic mail and any such notice shall only be effective upon receipt by the Lender.

SECTION 10.2 Right of Set Off. In addition to any rights now or hereafter granted under applicable law or otherwise, and not by way of limitation of any such rights, upon the occurrence of an Event of Default and the commencement of remedies described in Section 9.2, the Lender is authorized at any time and from time to time, without presentment, demand, protest or other notice of any kind (all of which rights being hereby expressly waived), to set-off and to appropriate and apply any and all deposits (general or special) and any other indebtedness at any time held or owing by the Lender (including, without limitation, branches, agencies or Affiliates of the Lender wherever located) to or for the credit or the account of the Borrower against obligations and liabilities of the Borrower to the Lender hereunder, under the Term Loan Notes, the other Loan Documents or otherwise, irrespective of whether the Lender shall have made any demand hereunder and although such obligations, liabilities or claims, or any of them, may be contingent or unmatured, and any such set-off shall be deemed to have been made

immediately upon the occurrence of an Event of Default even though such charge is made or entered on the books of the Lender subsequent thereto.

SECTION 10.3 No Waiver; Remedies Cumulative. No failure or delay on the part of the Lender in exercising any right, power or privilege hereunder or under any other Loan Document and no course of dealing between the Borrower and the Lender shall operate as a waiver thereof; nor shall any single or partial exercise of any right, power or privilege hereunder or under any other Loan Document preclude any other or further exercise thereof or the exercise of any other right, power or privilege hereunder or thereunder. The rights and remedies provided herein are cumulative and not exclusive of any rights or remedies which the Lender would otherwise have. No notice to or demand on the Borrower in any case shall entitle the Borrower to any other or further notice or demand in similar or other circumstances or constitute a waiver of the rights of the Lender to any other or further action in any circumstances without notice or demand.

SECTION 10.4 Payment of Expenses, etc. The Borrower agrees to: (i) pay all reasonable out of pocket costs and expenses of (A) each Lender-Related Person in connection with the administration of this Loan Agreement and the other Loan Documents and the documents and instruments referred to therein and any amendment, waiver, consent or assignment relating hereto and thereto including, but not limited to, any such amendments, waivers or consents resulting from or related to any work out, renegotiation or restructure relating to the performance by the Borrower under this Loan Agreement, and (B) the Lender in connection with enforcement of the Loan Documents and the documents and instruments referred to therein (including, without limitation, in connection with any such enforcement, the reasonable fees and disbursements of counsel for the Lender) and (ii) indemnify each Lender-Related Person from and hold each of them harmless against any and all losses, liabilities, claims, damages or expenses incurred by any of them as a result of, or arising out of, or in any way related to, or by reason of, any investigation, litigation or other proceeding (whether or not the Lender is a party thereto) related to the entering into and/or performance of any Loan Document or the use of proceeds of the Loans or the consummation of any other transactions contemplated in any Loan Document, including, without limitation, the reasonable fees and disbursements of counsel incurred in connection with any such investigation, litigation or other proceeding, provided that the Borrower shall not be responsible for any such losses, liabilities, claims, damages or expenses to the extent incurred by reason of gross negligence or willful misconduct on the part of the Person to be indemnified, and provided further that in no event shall the Borrower have any liability with respect to the settlement or compromise of any claim or proceeding effected without its prior written consent nor shall the Borrower be liable for the fees and disbursements of more than one firm of attorneys in connection with the same matter in the same jurisdiction for all Persons indemnified.

SECTION 10.5 Amendments, Waivers and Consents. Neither this Loan Agreement nor any other Loan Document nor any of the terms hereof or thereof may be amended, changed, waived, discharged or terminated unless such amendment, change, waiver, discharge or termination is in writing and signed by the Lender and the Borrower.

SECTION 10.6 Counterparts; Facsimile. This Loan Agreement may be executed in any number of counterparts, each of which when so executed and delivered shall be an original, but all of which shall constitute one and the same instrument. It shall not be necessary in making proof of this Loan Agreement to produce or account for more than one such counterpart. Delivery of executed counterparts by facsimile or electronic mail shall be as effective as an original and shall constitute a representation that an original will be delivered.

SECTION 10.7 Headings. The headings of the sections and subsections hereof are provided for convenience only and shall not in any way affect the meaning or construction of any provision of this Loan Agreement.

SECTION 10.8 Survival of Indemnification and Representations and Warranties. All indemnities set forth herein and all representations and warranties made herein shall survive the execution and delivery of this Loan Agreement, the making of the Loans, and the repayment of the Loans and other obligations hereunder.

SECTION 10.9 Time. All references to time herein shall be references to Eastern Standard Time or Eastern Daylight time, as the case may be, unless specified otherwise.

SECTION 10.10 Severability. If any provision of any of the Loan Documents is determined to be illegal, invalid or unenforceable, such provision shall be fully severable and the remaining provisions shall remain in full force and effect and shall be construed without giving effect to the illegal, invalid or unenforceable provisions.

SECTION 10.11 Entirety. This Loan Agreement together with the other Loan Documents represent the entire agreement of the parties hereto and thereto, and supersede all prior agreements and understandings, oral or written, if any, including any commitment letters or correspondence relating to the Loan Documents or the transactions contemplated herein and therein.

SECTION 10.12 Confidentiality. The Lender agrees that it will use its reasonable best efforts to keep confidential and to cause any representative designated under Section 7.10 to keep confidential any nonpublic information from time to time supplied to it under or in connection with any Loan Document (the "Information"), provided, however, that nothing herein shall affect the disclosure of any such Information to (a) the extent the Lender in good faith believes such disclosure is required by statute, rule, regulation or judicial process, (b) the extent requested by any regulatory authority having jurisdiction over the Lender or its Affiliates (including any self-regulatory authority) which has been notified of the confidential nature of such Information, (c) counsel for the Lender or to its accountants, (d) bank examiners or auditors or comparable Persons, (e) any Affiliate of the Lender, (f) (i) any assignee, transferee or participant or (ii) any potential assignee, transferee or participant of all or any portion of the Lender's rights under this Loan Agreement, in each case, who is notified of the confidential nature of the Information and agrees to be bound by this provision or provisions reasonably comparable hereto or (g) any other Person in connection with any litigation to which the Lender

is a party, and provided further that the Lender shall not have any obligation under this Section 10.12 to the extent any such Information becomes available on a nonconfidential basis from a source other than the Borrower or its Subsidiaries or that any Information becomes publicly available other than by a breach of this Section 10.12.

SECTION 10.13 Binding Effect. This Loan Agreement shall become effective when it shall have been executed by the Borrower and the Lender and thereafter this Loan Agreement shall be binding upon and inure to the benefit of the Borrower and the Lender, together with their respective successors and assigns.

SECTION 10.14 USA Patriot Act Notice. The Lender hereby notifies the Borrower that pursuant to the requirements of the USA Patriot Act (Title III of Pub. L. 107-56 (signed into law October 26, 2001)) (the "Act"), it is required to obtain, verify and record information that identifies the Borrower, which information includes the name and address of the Borrower and other information that will allow the Lender to identify the Borrower in accordance with the Act.

SECTION 10.15 No Fiduciary Responsibility. The Borrower acknowledges and agrees that in connection with all aspects of each transaction contemplated by this Loan Agreement, the Borrower, on the one hand, and the Lender, on the other hand, have an arms-length business relationship that creates no fiduciary duty on the part of either party hereto, and the Borrower expressly disclaims any fiduciary relationship.

SECTION 10.16 Governing Law. THIS LOAN AGREEMENT AND THE OTHER LOAN DOCUMENTS AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER AND THEREUNDER SHALL BE GOVERNED BY AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH THE LAWS OF THE STATE OF NEW YORK.

SECTION 10.17 Waiver of Jury Trial. EACH OF THE PARTIES TO THIS LOAN AGREEMENT HEREBY IRREVOCABLY WAIVES ALL RIGHT TO TRIAL BY JURY IN ANY ACTION, PROCEEDING OR COUNTERCLAIM ARISING OUT OF OR RELATING TO THIS LOAN AGREEMENT, ANY OF THE OTHER LOAN DOCUMENTS OR THE TRANSACTIONS CONTEMPLATED HEREIN AND THEREIN.

SECTION 10.18 Assignments and Participations. The Lender may:

(a) with the written consent of the Borrower, such consent not to be unreasonably withheld, assign to one or more Persons all or a portion of its rights and obligations under the Loan Agreement, provided, however, that such consent is not required (i) if the assignment is to an Affiliate of the Lender, or (ii) an Event of Default has occurred and is continuing. Upon the execution of an assignment agreement with the lender, the assignee thereunder shall be a party hereto and have the rights and obligations assigned to it by the Lender;

(b) sell participations to one or more banks or other entities (other than the Borrower or any of its Affiliates) in or to all or a portion of its rights and/or obligations under

this Loan Agreement without the consent of the Borrower, provided, however, that (i) the Lender's obligations under this Loan Agreement shall remain unchanged and (ii) the Borrower shall continue to deal solely and directly with the Lender in connection with the Lender's rights and obligations under this Loan Agreement; or

(c) pledge or assign a security interest in all or any portion of its rights under this Loan Agreement (including under the Term Loan Notes) to secure obligations of the Lender, including any pledge or assignment to secure obligations to a Federal Reserve Bank; provided that no such pledge or assignment shall release the Lender from any of its obligations hereunder or substitute any such pledgee or assignee for the Lender as a party hereto.

LENDER:

LLOYDS TSB BANK PLC, acting through its New York branch

By: _____
Name: _____
Title: _____

Mario Del Duca
Associate Director
Corporate Banking USA
D029

By: _____
Name: _____
Title: _____

Windsor R. Davies
Managing Director
Corporate Banking USA
D061

EXHIBIT A
FORM OF NOTE

US$_____ _____ __, _____

FOR VALUE RECEIVED, Gulf Power Company (the "Borrower") unconditionally promises to pay to the order of Lloyds TSB Bank PLC, acting through its New York Branch (the "Lender"), to and for any account designated by the Lender, the principal sum of _____ Million Dollars ($_____) pursuant to the Term Loan Agreement, dated as of April 2, 2008, between the Borrower and the Lender (as the same may be amended, supplemented or otherwise modified from time to time, the "Loan Agreement").

The outstanding principal of this Note and any accrued interest thereon shall be repaid as set forth in the Loan Agreement, with final payment on the Maturity Date (as defined in the Loan Agreement).

All payments of principal and interest on this Note shall be payable in lawful money of the United States of America in immediately available funds without set-off, defense or counterclaim.

This Note is issued pursuant to the terms of the Loan Agreement and is subject to the terms and conditions and entitled to the benefits therein provided. Upon the occurrence of an Event of Default (as defined in the Loan Agreement), the principal of and the accrued interest on this Note may become due and payable in the manner and with the same effect as provided in the Loan Agreement, without presentment, demand, protest or notice of any kind unless otherwise expressly required therein.

Failure or delay of the holder of this Note to enforce any provision of this Note shall not be deemed a waiver of any such provision, nor shall the holder of this Note be estopped from enforcing any such provision at a later time. Any waiver of any provision hereof must be in writing. This Note shall be governed by, and interpreted in accordance with, the law of the State of New York.

GULF POWER COMPANY

By: _____
Name:
Title:

By: _____

Name:
Title:

EXHIBIT B
OFFICER'S CERTIFICATE

The undersigned, _____, the duly elected, qualified and acting Vice President and Chief Financial Officer of Gulf Power Company (the "Company"), does hereby certify pursuant to Section 5.1(b) of the Term Loan Agreement dated as of April 2, 2008 between the Company and Lloyds TSB Bank PLC, acting through its New York Branch, as Lender (the "Loan Agreement"), that, as of the date hereof, (i) there exists no Default or Event of Default and (ii) the Company is in compliance with the financial covenant set forth in Section 7.11 of the Loan Agreement, as demonstrated by the calculations on Schedule A attached hereto.

Capitalized terms used herein and not otherwise defined have the meanings given to them in the Loan Agreement.

Dated: _____ ___, 20__

By: _____
Name:
Title:

Schedule A

Financial Covenant Calculations
Indebtedness to Capitalization

As of _____ __, 20__

Compliance with Section 7.11:
Ratio of Indebtedness to Capitalization

(a)	Indebtedness	$
(b)	Capitalization	$
(c)	Ratio of Indebtedness to Capitalization	%

Maximum Allowed: .65 : 1.0

EXHIBIT A.3.

Description of Holder

$80,000,000 Promissory Note
$30,000,000 Promissory Note

Lloyds TSB Bank PLC
1251 Avenue of the Americas
New York, New York 10019

GULF POWER COMPANY **EXHIBIT A.4.**

Summary of Debt Expenses in Conjunction with the $110,000,000 Promissory Notes

Item Number	Issuance Expenses For:	Amount $
1	Lender Fee	110,000.00
2	Fees and Expenses of Counsel	2,142.35
	Total Expenses of Note	112,142.35

Exhibit A.5

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(X) ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2008
OR
( ) TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period from to

Commission File Number	Registrant, State of Incorporation, Address and Telephone Number	I.R.S. Employer Identification No.
1-3526	**The Southern Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-0690070
1-3164	**Alabama Power Company** (An Alabama Corporation) 600 North 18th Street Birmingham, Alabama 35291 (205) 257-1000	63-0004250
1-6468	**Georgia Power Company** (A Georgia Corporation) 241 Ralph McGill Boulevard, N.E. Atlanta, Georgia 30308 (404) 506-6526	58-0257110
0-2429	**Gulf Power Company** (A Florida Corporation) One Energy Place Pensacola, Florida 32520 (850) 444-6111	59-0276810
001-11229	**Mississippi Power Company** (A Mississippi Corporation) 2992 West Beach Gulfport, Mississippi 39501 (228) 864-1211	64-0205820
333-98553	**Southern Power Company** (A Delaware Corporation) 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308 (404) 506-5000	58-2598670

DOCUMENT NUMBER-DATE
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Securities registered pursuant to Section 12(b) of the Act:[1]

Each of the following classes or series of securities registered pursuant to Section 12(b) of the Act is listed on the New York Stock Exchange.

Title of each class		Registrant
Common Stock, $5 par value		**The Southern Company**
Class A preferred, cumulative, $25 stated capital		**Alabama Power Company**
5.20% Series	5.83% Series	
5.30% Series		
Senior Notes		
5 5/8% Series AA	5.875% Series II	
5 7/8% Series GG	6.375% Series JJ	
5.875% Series 2007B		
Class A Preferred Stock, non-cumulative, Par value $25 per share		**Georgia Power Company**
6 1/8% Series		
Senior Notes		
5.90% Series O	6% Series R	5.70% Series X
5.75% Series T	6% Series W	5.75% Series G[2]
6.375% Series 2007D	8.20% Series 2008C	
Long-term debt payable to affiliated trusts, $25 liquidation amount		
5 7/8% Trust Preferred Securities[3]		
Senior Notes		**Gulf Power Company**
5.25% Series H	5.75% Series I	
5.875% Series J		

1 As of December 31, 2008.

2 Assumed by Georgia Power Company in connection with its merger with Savannah Electric and Power Company, effective July 1, 2006.

3 Issued by Georgia Power Capital Trust VII and guaranteed by Georgia Power Company.

Senior Notes 5 5/8% Series E	**Mississippi Power Company**
Depositary preferred shares, each representing one-fourth of a share of preferred stock, cumulative, $100 par value 5.25% Series	

Securities registered pursuant to Section 12(g) of the Act:[4]

Title of each class			**Registrant**
Preferred stock, cumulative, $100 par value			**Alabama Power Company**
4.20% Series	4.60% Series	4.72% Series	
4.52% Series	4.64% Series	4.92% Series	
Preferred stock, cumulative, $100 par value			**Mississippi Power Company**
4.40% Series	4.60% Series		
4.72% Series			

4 As of December 31, 2008.

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Registrant	Yes	No
The Southern Company	x	
Alabama Power Company	x	
Georgia Power Company	x	
Gulf Power Company		x
Mississippi Power Company		x
Southern Power Company		x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes _ No X (Response applicable to all registrants.)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes X No _

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (X)

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Registrant	Large Accelerated Filer	Accelerated Filer	Non-accelerated Filer	Smaller Reporting Company
The Southern Company	X			
Alabama Power Company			X	
Georgia Power Company			X	
Gulf Power Company			X	
Mississippi Power Company			X	
Southern Power Company			X	

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes _ No X (Response applicable to all registrants.)

Aggregate market value of The Southern Company's common stock held by non-affiliates of The Southern Company at June 30, 2008: $26.9 billion. All of the common stock of the other registrants is held by The Southern Company. A description of each registrant's common stock follows:

Registrant	Description of Common Stock	Shares Outstanding at January 31, 2009
The Southern Company	Par Value $5 Per Share	777,621,764
Alabama Power Company	Par Value $40 Per Share	25,475,000
Georgia Power Company	Without Par Value	9,261,500
Gulf Power Company	Without Par Value	3,142,717
Mississippi Power Company	Without Par Value	1,121,000
Southern Power Company	Par Value $0.01 Per Share	1,000

Documents incorporated by reference: specified portions of The Southern Company's Definitive Proxy Statement on Schedule 14A relating to the 2009 Annual Meeting of Stockholders are incorporated by reference into PART III. In addition, specified portions of the Definitive Information Statements on Schedule 14C of Alabama Power Company, Georgia Power Company, and Mississippi Power Company relating to each of their respective 2009 Annual Meetings of Shareholders are incorporated by reference into PART III.

Southern Power Company meets the conditions set forth in General Instructions I(1)(a) and (b) of Form 10-K and is therefore filing this Form 10-K with the reduced disclosure format specified in General Instructions I(2)(b) and (c) of Form 10-K.

This combined Form 10-K is separately filed by The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company. Information contained herein relating to any individual company is filed by such company on its own behalf. Each company makes no representation as to information relating to the other companies.

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DEFINITIONS

When used in Items 1 through 5 and Items 9A through 15, the following terms will have the meanings indicated.

Term	Meaning
AFUDC	Allowance for Funds Used During Construction
Alabama Power	Alabama Power Company
AMEA	Alabama Municipal Electric Authority
Clean Air Act	Clean Air Act Amendments of 1990
Dalton	Dalton Utilities
DOE	United States Department of Energy
Duke Energy	Duke Energy Corporation
Energy Act of 1992	Energy Policy Act of 1992
Energy Act of 2005	Energy Policy Act of 2005
Energy Solutions	Southern Company Energy Solutions, Inc.
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FMPA	Florida Municipal Power Agency
FP&L	Florida Power & Light Company
Georgia Power	Georgia Power Company
Gulf Power	Gulf Power Company
Hampton	City of Hampton, Georgia
IBEW	International Brotherhood of Electrical Workers
IIC	Intercompany Interchange Contract
IPP	Independent Power Producer
IRP	Integrated Resource Plan
IRS	Internal Revenue Service
KUA	Kissimmee Utility Authority
MEAG	Municipal Electric Authority of Georgia
Mirant	Mirant Corporation
Mississippi Power	Mississippi Power Company
Moody's	Moody's Investors Service
NRC	Nuclear Regulatory Commission
OPC	Oglethorpe Power Corporation
OUC	Orlando Utilities Commission
power pool	The operating arrangement whereby the integrated generating resources of the traditional operating companies and Southern Power are subject to joint commitment and dispatch in order to serve their combined load obligations
PowerSouth	PowerSouth Energy Cooperative (formerly, Alabama Electric Cooperative, Inc.)
PPA	Power Purchase Agreement
Progress Energy Carolinas	Carolina Power & Light Company, d/b/a Progress Energy Carolinas, Inc.
Progress Energy Florida	Florida Power Corporation, d/b/a Progress Energy Florida, Inc.
PSC	Public Service Commission
registrants	The Southern Company, Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Southern Power Company

DEFINITIONS
(continued)

Term	Meaning
RFP	Request for Proposal
RUS	Rural Utility Service (formerly Rural Electrification Administration)
S&P	Standard and Poor's, a division of The McGraw-Hill Companies
Savannah Electric	Savannah Electric and Power Company (merged into Georgia Power on July 1, 2006)
SCS	Southern Company Services, Inc. (the system service company)
SEC	Securities and Exchange Commission
SEGCO	Southern Electric Generating Company
SEPA	Southeastern Power Administration
SERC	Southeastern Electric Reliability Council
SMEPA	South Mississippi Electric Power Association
Southern Company	The Southern Company
Southern Company system	Southern Company, the traditional operating companies, Southern Power, SEGCO, Southern Nuclear, SCS, SouthernLINC Wireless, and other subsidiaries
Southern Holdings	Southern Company Holdings, Inc.
SouthernLINC Wireless	Southern Communications Services, Inc.
Southern Nuclear	Southern Nuclear Operating Company, Inc.
Southern Power	Southern Power Company
Stone & Webster	Stone & Webster, Inc.
traditional operating companies	Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company
TVA	Tennessee Valley Authority
Westinghouse	Westinghouse Electric Company LLC

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

This Annual Report on Form 10-K contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales growth, customer growth, storm damage cost recovery and repairs, fuel cost recovery and other rate actions, environmental regulations and expenditures, earnings growth, dividend payout ratios, access to sources of capital, projections for postretirement benefit and nuclear decommissioning trust contributions, financing activities, completion of construction projects, plans and estimated costs for new generation resources, impacts of adoption of new accounting rules, unrecognized tax benefits related to leveraged lease transactions, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, IRS audits, and Mirant matters;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs;
- investment performance of Southern Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- regulatory approvals related to the potential Plant Vogtle expansion, including Georgia PSC and NRC approvals;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with neighboring utilities and other wholesale customers;
- the direct or indirect effect on Southern Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on Southern Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports filed by the registrants from time to time with the SEC.

The registrants expressly disclaim any obligation to update any forward-looking statements.

PART I

Item 1. BUSINESS

Southern Company was incorporated under the laws of Delaware on November 9, 1945. Southern Company is domesticated under the laws of Georgia and is qualified to do business as a foreign corporation under the laws of Alabama. Southern Company owns all of the outstanding common stock of Alabama Power, Georgia Power, Gulf Power, and Mississippi Power, each of which is an operating public utility company. The traditional operating companies supply electric service in the states of Alabama, Georgia, Florida, and Mississippi. More particular information relating to each of the traditional operating companies is as follows:

Alabama Power is a corporation organized under the laws of the State of Alabama on November 10, 1927, by the consolidation of a predecessor Alabama Power Company, Gulf Electric Company, and Houston Power Company. The predecessor Alabama Power Company had been in continuous existence since its incorporation in 1906.

Georgia Power was incorporated under the laws of the State of Georgia on June 26, 1930, and admitted to do business in Alabama on September 15, 1948. Effective July 1, 2006, Savannah Electric, formerly a wholly-owned subsidiary of Southern Company, was merged with and into Georgia Power.

Gulf Power is a Florida corporation that has had a continuous existence since it was originally organized under the laws of the State of Maine on November 2, 1925. Gulf Power was admitted to do business in Florida on January 15, 1926, in Mississippi on October 25, 1976, and in Georgia on November 20, 1984. Gulf Power became a Florida corporation after being domesticated under the laws of the State of Florida on November 2, 2005.

Mississippi Power was incorporated under the laws of the State of Mississippi on July 12, 1972, was admitted to do business in Alabama on November 28, 1972, and effective December 21, 1972, by the merger into it of the predecessor Mississippi Power Company, succeeded to the business and properties of the latter company. The predecessor Mississippi Power Company was incorporated under the laws of the State of Maine on November 24, 1924 and was admitted to do business in Mississippi on December 23, 1924 and in Alabama on December 7, 1962.

In addition, Southern Company owns all of the common stock of Southern Power, which is also an operating public utility company. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. Southern Power is a corporation organized under the laws of Delaware on January 8, 2001 and was admitted to do business in the States of Alabama, Florida, and Georgia on January 10, 2001, in the State of Mississippi on January 30, 2001, and in the State of North Carolina on February 19, 2007.

Southern Company also owns all the outstanding common stock or membership interests of SouthernLINC Wireless, Southern Nuclear, SCS, Southern Holdings, and other direct and indirect subsidiaries. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets these services to the public and also provides wholesale fiber optic solutions to telecommunication providers in the Southeast. Southern Nuclear operates and provides services to Alabama Power's and Georgia Power's nuclear plants. SCS is the system service company providing, at cost, specialized services to Southern Company and its subsidiary companies. Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses.

Alabama Power and Georgia Power each own 50% of the outstanding common stock of SEGCO. SEGCO is an operating public utility company that owns electric generating units with an aggregate capacity of 1,019,680 kilowatts at Plant Gaston on the Coosa River near Wilsonville, Alabama. Alabama Power and Georgia Power are each entitled to one-half of SEGCO's capacity and energy. Alabama Power acts as SEGCO's agent in the operation of SEGCO's units and furnishes coal to SEGCO as fuel for its units. SEGCO also owns one 230,000 volt transmission line extending from Plant Gaston to the Georgia state line at which point connection is made with the Georgia Power transmission line system.

Southern Company's segment information is included in Note 11 to the financial statements of Southern Company in Item 8 herein.

The registrants' Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports are made available on Southern Company's website, free of charge, as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC. Southern Company's internet address is www.southerncompany.com.

The Southern Company System

Traditional Operating Companies

The traditional operating companies own generation, transmission, and distribution facilities. See PROPERTIES in Item 2 herein for additional information on the traditional operating companies' generating facilities. The transmission facilities of each of the traditional operating companies are connected to the respective company's own generating plants and other sources of power and are interconnected with the transmission facilities of the other traditional operating companies and SEGCO by means of heavy-duty high voltage lines. For information on Georgia Power's integrated transmission system, see "Territory Served by the Traditional Operating Companies and Southern Power" herein.

Operating contracts covering arrangements in effect with principal neighboring utility systems provide for capacity exchanges, capacity purchases and sales, transfers of economy energy, and other similar transactions. Additionally, the traditional operating companies have entered into voluntary reliability agreements with the subsidiaries of Entergy Corporation, Florida Electric Power Coordinating Group, and TVA and with Progress Energy Carolinas, Duke Energy, South Carolina Electric & Gas Company, and Virginia Electric and Power Company, each of which provides for the establishment and periodic review of principles and procedures for planning and operation of generation and transmission facilities, maintenance schedules, load retention programs, emergency operations, and other matters affecting the reliability of bulk power supply. The traditional operating companies have joined with other utilities in the Southeast (including those referred to above) to form the SERC to augment further the reliability and adequacy of bulk power supply. Through the SERC, the traditional operating companies are represented on the National Electric Reliability Council.

The IIC provides for coordinating operations of the power producing facilities of the traditional operating companies and Southern Power and the capacities available to such companies from non-affiliated sources and for the pooling of surplus energy available for interchange. Coordinated operation of the entire interconnected system is conducted through a central power supply coordination office maintained by SCS. The available sources of energy are allocated to the traditional operating companies and Southern Power to provide the most economical sources of power consistent with reliable operation. The resulting benefits and savings are apportioned among each of the companies. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Intercompany Interchange Contract" of each registrant in Item 7 herein and Note 3 to the financial statements of each registrant, all under "FERC Matters – Intercompany Interchange Contract" in Item 8 herein for information on the settlement of the FERC proceeding related to the IIC.

Southern Company, each traditional operating company, Southern Power, Southern Nuclear, SEGCO, and other subsidiaries have contracted with SCS to furnish, at direct or allocated cost and upon request, the following services: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Southern Power and SouthernLINC Wireless have also secured from the traditional operating companies certain services which are furnished at cost and, in the case of Southern Power which is subject to FERC regulations, in compliance with such regulations.

Alabama Power and Georgia Power each have a contract with Southern Nuclear to operate Plant Farley and Plants Hatch and Vogtle, respectively. See "Regulation – Nuclear Regulation" herein for additional information.

Southern Power

Southern Power is an electric wholesale generation subsidiary with market-based rate authority from the FERC. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based prices in the wholesale market. Southern Power's business activities are not subject to traditional state regulation like the traditional operating companies but are subject to regulation by the FERC. Southern Power has attempted to insulate itself from significant fuel supply, fuel transportation, and electric transmission risks by making such risks the responsibility of the counterparties to the PPAs. However, Southern Power's future earnings will depend on the parameters of the wholesale market, federal regulation, and the efficient operation of its wholesale generating assets. For additional information on Southern Power's business activities, see MANAGEMENT'S DISCUSSION AND ANALYSIS – OVERVIEW – "Business Activities" of Southern Power in Item 7 herein.

In June 2008, Southern Power completed construction on Plant Franklin Unit 3 which added 659 megawatts to the Southern Company system generating capacity. In December 2008, Southern Power announced plans to construct a 720 megawatt electric generating plant in North Carolina. This new plant is expected to go into commercial operation in 2012. As of December 31, 2008, Southern Power had 7,555 megawatts of nameplate capacity in commercial operation.

Other Businesses

Southern Holdings is an intermediate holding subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses.

SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and markets its services to non-affiliates within the Southeast. SouthernLINC Wireless delivers multiple wireless communication options including push to talk, cellular service, text messaging, wireless internet access, and wireless data. Its system covers approximately 128,000 square miles in the Southeast. SouthernLINC Wireless also provides wholesale fiber optic solutions to telecommunication providers in the Southeast under the name Southern Telecom.

These efforts to invest in and develop new business opportunities offer potential returns exceeding those of rate-regulated operations. However, these activities also involve a higher degree of risk.

Construction Programs

The subsidiary companies of Southern Company are engaged in continuous construction programs to accommodate existing and estimated future loads on their respective systems. For estimated construction and environmental expenditures for the periods 2009 through 2011, see Note 7 to the financial statements of each traditional operating company and Southern Power under "Construction Program" and "Expansion Program", respectively, in Item 8 herein. Estimated construction costs in 2009 are expected to be apportioned approximately as follows: (in millions)

	Southern Company System*	Alabama Power	Georgia Power	Gulf Power	Mississippi Power	Southern Power
New generation	$1,953	$ -	$1,209	$ 6	$ 48	$ 690
Environmental	1,448	584	472	335	28	-
Other generating facilities, including associated plant substations	543	232	178	42	11	59
New business	411	196	170	29	16	-
Transmission	434	76	313	25	20	-
Distribution	404	157	189	29	30	-
Nuclear fuel	238	90	148	-	-	-
General plant	222	79	75	12	10	-
	$5,653	$1,414	$2,754	$478	$163	$ 749

*These amounts include the traditional operating companies and Southern Power (as detailed in the table above) as well as the amounts for the other subsidiaries. See "Other Businesses" herein for additional information.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

Under Georgia law, Georgia Power is required to file an IRP for approval by the Georgia PSC. Through the IRP process, the Georgia PSC must pre-certify the construction of new power plants and new PPAs. See "Rate Matters – Integrated Resource Planning" herein for additional information.

See "Regulation – Environmental Statutes and Regulations" herein for additional information with respect to certain existing and proposed environmental requirements and PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information concerning Alabama Power's, Georgia Power's, and Southern Power's joint ownership of certain generating units and related facilities with certain non-affiliated utilities.

Financing Programs

See each of the registrant's MANAGEMENT'S DISCUSSION AND ANALYSIS – FINANCIAL CONDITION AND LIQUIDITY in Item 7 herein and Note 6 to the financial statements of each registrant in Item 8 herein for information concerning financing programs.

Fuel Supply

The traditional operating companies' and SEGCO's supply of electricity is derived predominantly from coal. Southern Power's supply of electricity is primarily fueled by natural gas. See MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATION – "Fuel and Purchased Power Expenses" of Southern Company and each traditional operating company in Item 7 herein for information regarding the electricity generated and the average cost of fuel in cents per net kilowatt-hour generated for the years 2006 through 2008.

The traditional operating companies have agreements in place from which they expect to receive approximately 100% of their coal burn requirements in 2009. These agreements have terms ranging between one and seven years. In 2008, the weighted average sulfur content of all coal burned by the traditional operating companies was 0.74% sulfur. This sulfur level, along with banked and purchased sulfur dioxide allowances, allowed the traditional operating companies to remain within limits set by the Phase II acid rain requirements of the Clean Air Act. In 2008, Southern Company purchased approximately $63.5 million of sulfur dioxide and nitrogen oxide emission allowances to be used in current and future periods. As additional environmental regulations are proposed that impact the utilization of coal, the traditional operating companies' fuel mix will be monitored to ensure that the traditional operating companies remain in compliance with applicable laws and regulations. Additionally, Southern Company and the traditional operating companies will continue to evaluate the need to purchase additional emission allowances and the timing of capital expenditures for emission control equipment. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each traditional operating company in Item 7 herein for information on the Clean Air Act and global climate issues.

SCS, acting on behalf of the traditional operating companies and Southern Power, has agreements in place for the natural gas burn requirements of the Southern Company system. For 2009, SCS has contracted for 220 billion cubic feet of natural gas supply. These agreements cover remaining terms up to 10 years. In addition to gas supply, SCS has contracts in place for both firm gas transportation and storage. Management believes that these contracts provide sufficient natural gas supplies, transportation, and storage to ensure normal operations of the Southern Company system's natural gas generating units.

Changes in fuel prices to the traditional operating companies are generally reflected in fuel adjustment clauses contained in rate schedules. See "Rate Matters – Rate Structure and Cost Recovery Plans" herein for additional information. Southern Power's PPAs generally provide that the counterparty is responsible for substantially all of the cost of fuel.

Alabama Power and Georgia Power have numerous contracts covering a portion of their nuclear fuel needs for uranium, conversion services, enrichment services, and fuel fabrication. These contracts have varying expiration dates and most of them are for less than 10 years. Management believes that sufficient capacity for nuclear fuel supplies and processing exists to preclude the impairment of normal operations of the Southern Company system's nuclear generating units.

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, that provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent fuel in 1998, as required by the contracts, and Alabama Power and Georgia Power are pursuing legal remedies against the government for breach of contract. See Note 3 to the financial statements of Southern Company, Alabama Power, and Georgia Power under "Nuclear Fuel Disposal Costs" in Item 8 herein for additional information.

Territory Served by the Traditional Operating Companies and Southern Power

The territory in which the traditional operating companies provide electric service comprises most of the states of Alabama and Georgia together with the northwestern portion of Florida and southeastern Mississippi. In this territory there are non-affiliated electric distribution systems which obtain some or all of their power requirements either directly or indirectly from the traditional operating companies. The territory has an area of approximately 120,000 square miles and an estimated population of approximately 13 million. Southern Power sells electricity at market-based prices in the wholesale market to investor-owned utilities, IPPs, municipalities, and electric cooperatives.

Alabama Power is engaged, within the State of Alabama, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity at retail in over 650 communities (including Anniston, Birmingham, Gadsden, Mobile, Montgomery, and Tuscaloosa) and at wholesale to 15 municipally-owned electric distribution systems, 11 of which are served indirectly through sales to AMEA, and two rural distributing cooperative associations. Alabama Power owns coal reserves near its Plant Gorgas and uses the output of coal from the reserves in its generating plants. Alabama Power also sells, and cooperates with dealers in promoting the sale of, electric appliances.

Georgia Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity within the State of Georgia at retail in over 600 communities (including Athens, Atlanta, Augusta, Columbus, Macon, Rome, and Savannah), as well as in rural areas, and at wholesale currently to OPC, MEAG, Dalton, Hampton, and 30 electric cooperatives.

Gulf Power is engaged, within the northwestern portion of Florida, in the generation and purchase of electricity and the transmission, distribution, and sale of such electricity at retail in 71 communities (including Pensacola, Panama City, and Fort Walton Beach), as well as in rural areas, and at wholesale to a non-affiliated utility and a municipality.

Mississippi Power is engaged in the generation and purchase of electricity and the transmission, distribution, and sale of such energy within 23 counties in southeastern Mississippi, at retail in 123 communities (including Biloxi, Gulfport, Hattiesburg, Laurel, Meridian, and Pascagoula), as well as in rural areas, and at wholesale to one municipality, six rural electric distribution cooperative associations, and one generating and transmitting cooperative.

For information relating to kilowatt-hour sales by classification for the traditional operating companies, see MANAGEMENT'S DISCUSSION AND ANALYSIS – RESULTS OF OPERATIONS of each traditional operating company in Item 7 herein. Also, for information relating to the sources of revenues for Southern Company, each traditional operating company, and Southern Power, reference is made to Item 6 herein.

The RUS has authority to make loans to cooperative associations or corporations to enable them to provide electric service to customers in rural sections of the country. There are 71 electric cooperative organizations operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

One of these organizations, PowerSouth, is a generating and transmitting cooperative selling power to several distributing cooperatives, municipal systems, and other customers in south Alabama and northwest Florida. PowerSouth owns generating units with approximately 1,776 megawatts of nameplate capacity, including an undivided 8.16% ownership interest in Alabama Power's Plant Miller Units 1 and 2. PowerSouth's facilities were financed with RUS loans secured by long-term contracts requiring distributing cooperatives to take their requirements from PowerSouth to the extent such energy is available.

Alabama Power and Gulf Power have entered into separate agreements with PowerSouth involving interconnection between their respective systems. The delivery of capacity and energy from PowerSouth to certain distributing cooperatives in the service areas of Alabama Power and Gulf Power is governed by the Southern Company/PowerSouth Network Transmission Service Agreement. The rates for this service to PowerSouth are on file with the FERC. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for details of Alabama Power's joint-ownership with PowerSouth of a portion of Plant Miller.

Four electric cooperative associations, financed by the RUS, operate within Gulf Power's service area. These cooperatives purchase their full requirements from PowerSouth and SEPA (a federal power marketing agency). A non-affiliated utility also operates within Gulf Power's service area and purchases its full requirements from Gulf Power.

Mississippi Power has an interchange agreement with SMEPA, a generating and transmitting cooperative, pursuant to which various services are provided, including the furnishing of protective capacity by Mississippi Power to SMEPA.

There are also 65 municipally-owned electric distribution systems operating in the territory in which the traditional operating companies provide electric service at retail or wholesale.

Forty-eight municipally-owned electric distribution systems and one county-owned system receive their requirements through MEAG, which was established by a Georgia state statute in 1975. MEAG serves these requirements from self-owned generation facilities, some of which are acquired and jointly-owned with Georgia Power, power purchased from Georgia Power, and purchases from other resources. MEAG also has a pseudo scheduling and services agreement with

Georgia Power. Dalton serves its requirements from self-owned generation facilities, some of which are acquired and jointly-owned with Georgia Power, and through purchases from Georgia Power pursuant to their partial requirements tariff. In addition, Georgia Power serves the full requirements of Hampton's electric distribution system under a market-based contract. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Georgia Power has entered into substantially similar agreements with Georgia Transmission Corporation (formerly OPC's transmission division), MEAG, and Dalton providing for the establishment of an integrated transmission system to carry the power and energy of all parties. The agreements require an investment by each party in the integrated transmission system in proportion to its respective share of the aggregate system load. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Southern Power has PPAs with some of the traditional operating companies and with other investor owned utilities, IPPs, municipalities, and electric cooperatives. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" of Southern Power in Item 7 herein for additional information concerning Southern Power's PPAs.

SCS, acting on behalf of the traditional operating companies, also has a contract with SEPA providing for the use of the traditional operating companies' facilities at government expense to deliver to certain cooperatives and municipalities, entitled by federal statute to preference in the purchase of power from SEPA, quantities of power equivalent to the amounts of power allocated to them by SEPA from certain United States government hydroelectric projects.

The retail service rights of all electric suppliers in the State of Georgia are regulated by the Territorial Electric Service Act of 1973. Pursuant to the provisions of this Act, all areas within existing municipal limits were assigned to the primary electric supplier therein. Areas outside of such municipal limits were either to be assigned or to be declared open for customer choice of supplier by action of the Georgia PSC pursuant to standards set forth in this Act. Consistent with such standards, the Georgia PSC has assigned substantially all of the land area in the state to a supplier. Notwithstanding such assignments, this Act provides that any new customer locating outside of 1973 municipal limits and having a connected load of at least 900 kilowatts may exercise a one-time choice for the life of the premises to receive electric service from the supplier of its choice. See "Competition" herein for additional information.

Pursuant to the 1956 Utility Act, the Mississippi PSC issued "Grandfather Certificates" of public convenience and necessity to Mississippi Power and to six distribution rural cooperatives operating in southeastern Mississippi, then served in whole or in part by Mississippi Power, authorizing them to distribute electricity in certain specified geographically described areas of the state. The six cooperatives serve approximately 325,000 retail customers in a certificated area of approximately 10,300 square miles. In areas included in a "Grandfather Certificate," the utility holding such certificate may, without further certification, extend its lines up to five miles; other extensions within that area by such utility, or by other utilities, may not be made except upon a showing of, and a grant of a certificate of, public convenience and necessity. Areas included in such a certificate which are subsequently annexed to municipalities may continue to be served by the holder of the certificate, irrespective of whether it has a franchise in the annexing municipality. On the other hand, the holder of the municipal franchise may not extend service into such newly annexed area without authorization by the Mississippi PSC.

Competition

The electric utility industry in the United States is continuing to evolve as a result of regulatory and competitive factors. Among the early primary agents of change was the Energy Act of 1992 which allowed IPPs to access a utility's transmission network in order to sell electricity to other utilities.

The competition for retail energy sales among competing suppliers of energy is influenced by various factors, including price, availability, technological advancements, service, and reliability. These factors are, in turn, affected by, among other influences, regulatory, political, and environmental considerations, taxation, and supply.

Generally, the traditional operating companies have experienced, and expect to continue to experience, competition in their respective retail service territories in varying degrees as the result of self-generation (as described above) by

customers and other factors. See also "Territory Served by the Traditional Operating Companies and Southern Power" herein for additional information concerning suppliers of electricity operating within or near the areas served at retail by the traditional operating companies.

Southern Power competes with investor owned utilities, IPPs, and others for wholesale energy sales primarily in the Southeastern United States wholesale market. The needs of this market are driven by the demands of end users in the Southeast and the generation available. Southern Power's success in wholesale energy sales is influenced by various factors including reliability and availability of Southern Power's plants, availability of transmission to serve the demand, price, and Southern Power's ability to contain costs.

Alabama Power currently has cogeneration contracts in effect with nine industrial customers. Under the terms of these contracts, Alabama Power purchases excess generation of such companies. During 2008, Alabama Power purchased approximately 114 million kilowatt-hours from such companies at a cost of $5.6 million.

Georgia Power currently has contracts in effect with eight small power producers whereby Georgia Power purchases their excess generation. During 2008, Georgia Power purchased 7.2 million kilowatt-hours from such companies at a cost of $1.0 million. Georgia Power has PPAs for electricity with two cogeneration facilities. Payments are subject to reductions for failure to meet minimum capacity output. During 2008, Georgia Power purchased 222.9 million kilowatt-hours at a cost of $67.9 million from these facilities.

Also during 2008, Georgia Power purchased energy from seven customer-owned generating facilities. Six of the seven customers provide only energy to Georgia Power. These six customers make no capacity commitment and are not dispatched by Georgia Power. Georgia Power does have a contract with the remaining customer for eight megawatts of dispatchable capacity and energy. During 2008, Georgia Power purchased a total of 59.1 million kilowatt-hours from the seven customers at a cost of approximately $3.0 million.

Gulf Power currently has agreements in effect with various industrial, commercial, and qualifying facilities pursuant to which Gulf Power purchases "as available" energy from customer-owned generation. During 2008, Gulf Power purchased 41.1 million kilowatt-hours from such companies for approximately $2.7 million.

Mississippi Power currently has a cogeneration agreement in effect with one of its industrial customers. Under the terms of this contract, Mississippi Power purchases any excess generation. During 2008, this customer had no excess generation.

Seasonality

The demand for electric power generation is affected by seasonal differences in the weather. At the traditional operating companies and Southern Power, the demand for power peaks during the summer months, with market prices reflecting the demand of power and available generating resources at that time. Power demand peaks can also be recorded during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies, and Southern Power have historically sold less power when weather conditions are milder.

Regulation

State Commissions

The traditional operating companies are subject to the jurisdiction of their respective state PSCs. The PSCs have broad powers of supervision and regulation over public utilities operating in the respective states, including their rates, service regulations, sales of securities (except for the Mississippi PSC), and, in the cases of the Georgia PSC and the Mississippi PSC, in part, retail service territories. See "Territory Served by the Traditional Operating Companies and Southern Power" and "Rate Matters" herein for additional information.

Federal Power Act

The traditional operating companies, Southern Power and its generation subsidiaries, and SEGCO are all public utilities engaged in wholesale sales of energy in interstate commerce and therefore are subject to the rate, financial, and accounting jurisdiction of the FERC under the Federal Power Act. The FERC must approve certain financings and allows an "at cost standard" for services rendered by system service companies such as SCS. The FERC is also authorized to establish regional reliability organizations which are authorized to enforce reliability standards, to address impediments to the construction of transmission, and to prohibit manipulative energy trading practices.

Alabama Power and Georgia Power are also subject to the provisions of the Federal Power Act or the earlier Federal Water Power Act applicable to licensees with respect to their hydroelectric developments. Among the hydroelectric projects subject to licensing by the FERC are 14 existing Alabama Power generating stations having an aggregate installed capacity of 1,662,400 kilowatts and 18 existing Georgia Power generating stations having an aggregate installed capacity of 1,074,696 kilowatts.

On May 22, 2008, the FERC issued a new 30-year license for the Morgan Falls project, located on the Chattahoochee River near Atlanta, with an effective start date of March 1, 2009. In 2007, Georgia Power began the relicensing process for Bartlett's Ferry which is located on the Chattahoochee River near Columbus, Georgia. The current Bartlett's Ferry license expires in 2014 and the application for a new license is expected to be submitted to the FERC in 2012. In July 2005, Alabama Power filed two applications with the FERC for new 50-year licenses for its seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine developments expired in July and August 2007. The FERC issued an annual license for the Coosa developments in August 2007 and issued an annual license for the Warrior developments in September 2007. Both of these licenses were automatically renewed in 2008 pursuant to FERC regulations. These annual licenses provide the FERC with additional time to complete its review of the license applications. In 2006, Alabama Power initiated the process of developing an application to relicense the Martin hydroelectric project located on the Tallapoosa River. The current Martin license will expire in 2013 and the application for a new license is expected to be filed with the FERC in 2011. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Hydro Relicensing" of Alabama Power in Item 7 herein for additional information.

Georgia Power and OPC also have a license, expiring in 2027, for the Rocky Mountain Plant, a pure pumped storage facility of 847,800 kilowatt capacity. See PROPERTIES – "Jointly-Owned Facilities" in Item 2 herein for additional information.

Licenses for all projects, excluding those discussed above, expire in the period 2015-2034 in the case of Alabama Power's projects and in the period 2014-2039 in the case of Georgia Power's projects.

Upon or after the expiration of each license, the United States Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. In the event of takeover or relicensing to another, the original licensee is to be compensated in accordance with the provisions of the Federal Power Act, such compensation to reflect the net investment of the licensee in the project, not in excess of the fair value of the property, plus reasonable damages to other property of the licensee resulting from the severance therefrom of the property. If the FERC does not act on the new license application prior to the expiration of the existing license, the FERC is required to issue annual licenses, under the same terms and conditions of the existing license, until a new license is issued.

Nuclear Regulation

Alabama Power, Georgia Power, and Southern Nuclear are subject to regulation by the NRC. The NRC is responsible for licensing and regulating nuclear facilities and materials and for conducting research in support of the licensing and regulatory process, as mandated by the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and the Nuclear Nonproliferation Act of 1978; and in accordance with the National Environmental Policy Act of 1969, as amended, and other applicable statutes. These responsibilities also include protecting public health and safety, protecting the environment, protecting and safeguarding nuclear

materials and nuclear power plants in the interest of national security, and assuring conformity with antitrust laws.

The NRC operating licenses for Plant Vogtle units 1 and 2 currently expire in January 2027 and February 2029, respectively. In January 2002, the NRC granted Georgia Power a 20-year extension of the licenses for both units at Plant Hatch which permits the operation of units 1 and 2 until 2034 and 2038, respectively. Georgia Power filed an application with the NRC in June 2007 to extend the licenses for Plant Vogtle units 1 and 2 for an additional 20 years. Georgia Power anticipates the NRC may make a decision regarding the license extension for Plant Vogtle in 2009. In May 2005, the NRC granted Alabama Power a 20-year extension of the licenses for both units at Plant Farley which permits operation of units 1 and 2 until 2037 and 2041, respectively.

In August 2006, Southern Nuclear, on behalf of Georgia Power, OPC, MEAG, and Dalton (collectively, Owners), filed an application with the NRC for an early site permit approving two additional nuclear units on the site of Plant Vogtle. See Note 4 to the financial statements of Southern Company and Georgia Power in Item 8 herein for additional information on these co-owners. On March 31, 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license for the new units.

On April 8, 2008, Georgia Power, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse and Stone & Webster (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction Projects" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Nuclear - Construction" of Georgia Power in Item 7 herein and Note 3 to the financial statements of Southern Company and Georgia Power under "Nuclear" and "Nuclear Construction," respectively in Item 8 herein for additional information.

See Notes 1 and 9 to the financial statements of Southern Company, Alabama Power, and Georgia Power in Item 8 herein for information on nuclear decommissioning costs and nuclear insurance.

FERC Matters

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters" of each of the registrants in Item 7 herein for information on matters regarding the FERC.

Environmental Statutes and Regulations

Southern Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Compliance with these existing environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. There is no assurance, however, that all such costs will be recovered.

Compliance with the federal Clean Air Act and resulting regulations has been, and will continue to be, a significant focus for Southern Company, each traditional operating company, Southern Power, and SEGCO. In addition, existing environmental laws and regulations may be changed or new laws and regulations may be adopted or otherwise become applicable to Southern Company, the traditional operating companies, Southern Power, or SEGCO, including laws and regulations designed to address global climate change, air quality, water quality, or other environmental, public health, and welfare concerns. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Company and each of the traditional operating companies in Item 7 herein for additional information about the Clean Air Act and other environmental issues, including the litigation brought by the EPA under the New Source Review provisions of the Clean Air Act and possible climate change legislation and regulation. Also see MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Environmental Matters" of Southern Power in Item 7 herein for information about the environmental issues and possible climate change legislation and regulation.

Southern Company, the traditional operating companies, Southern Power, and SEGCO are unable to predict at this time what additional steps they may be required to take as a result of the implementation of existing or future requirements pertaining to climate change, air quality, water quality, and management of waste materials and combustion byproducts, including coal ash, but such steps could adversely affect system operations and result in substantial additional costs.

The outcome of the matters mentioned above under "Regulation" cannot now be determined, except that these developments may result in delays in obtaining appropriate licenses for generating facilities, increased construction and operating costs, or reduced generation, the nature and extent of which, while not determinable at this time, could be substantial.

Rate Matters

Rate Structure and Cost Recovery Plans

The rates and service regulations of the traditional operating companies are uniform for each class of service throughout their respective service areas. Rates for residential electric service are generally of the block type based upon kilowatt-hours used and include minimum charges. Residential and other rates contain separate customer charges. Rates for commercial service are presently of the block type and, for large customers, the billing demand is generally used to determine capacity and minimum bill charges. These large customers' rates are generally based upon usage by the customer and include rates with special features to encourage off-peak usage. Additionally, Alabama Power, Gulf Power, and Mississippi Power are generally allowed by their respective state PSCs to negotiate the terms and cost of service to large customers. Such terms and cost of service, however, are subject to final state PSC approval.

Fuel and net purchased energy costs are recovered through specific fuel cost recovery provisions at the traditional operating companies. These fuel cost recovery provisions are adjusted to reflect increases or decreases in such costs as needed. Gulf Power's and Mississippi Power's fuel cost recovery provisions are adjusted annually to reflect increases or decreases in such costs. Georgia Power expects to file for an adjustment to its fuel cost recovery rate on March 13, 2009. Alabama Power's fuel clause is adjusted as required. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

Approved environmental compliance and storm damage costs are recovered at Alabama Power, Gulf Power, and Mississippi Power through cost recovery provisions approved by their respective state PSCs. Within limits approved by their respective PSCs, these rates are adjusted to reflect increases or decreases in such costs as required.

Georgia Power's environmental compliance costs were recovered in base rates through 2007. Under the 2007 retail rate plan, an environmental compliance cost recovery tariff was implemented effective January 1, 2008 to allow for recovery of most of the costs related to environmental controls scheduled for completion between 2008 and 2010 that are mandated by state and federal regulation. Georgia Power has also requested that the Georgia PSC certify the construction of environmental controls for Plants Branch and Hammond. Georgia Power also continues to recover storm damage and new plant costs through its base rates. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction Projects - Nuclear" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Nuclear - Construction" of Georgia Power in Item 7 herein for information regarding legislation currently being considered in the State of Georgia to allow recovery of financing costs for nuclear construction projects during the construction period.

Alabama Power recovers the cost of certificated new plant and purchased power capacity and Gulf Power recovers purchased power capacity and conservation costs through cost recovery provisions which are adjusted as required to reflect increases or decreases in such costs as needed. Revenues are adjusted for differences between recoverable costs and amounts actually recovered in current rates.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "PSC Matters" of Southern Company and each of the traditional operating companies in Item 7 herein and Note 3 to the financial statements of Southern Company under "Alabama Power Retail Regulatory Matters" and "Georgia Power Retail

Regulatory Matters" and Note 3 to the financial statements of each of the traditional operating companies under "Retail Regulatory Matters" in Item 8 herein for a discussion of rate matters. Also, see Note 1 to the financial statements of Southern Company and each of the traditional operating companies in Item 8 herein for a discussion of recovery of fuel costs, storm damage costs, and environmental compliance costs through rates.

The traditional operating companies and Southern Power are authorized by the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "FERC Matters – Market-Based Rate Authority" of each registrant in Item 7 herein and Note 3 to the financial statements of each registrant under "FERC Matters – Market-Based Rate Authority" in Item 8 herein for a discussion of rate matters.

Integrated Resource Planning

Triennially, Georgia Power must file an IRP with the Georgia PSC that specifies how it intends to meet the future electrical needs of its customers through a combination of demand-side and supply-side resources. The Georgia PSC under state law will certify any new demand-side or supply-side resources. Once certified, the lesser of actual or certified construction costs and purchased power costs will be recoverable through rates.

In July 2007, the Georgia PSC approved Georgia Power's 2007 IRP including the following provisions: (1) retiring the coal units at Plant McDonough and replacing them with combined-cycle natural gas units; (2) approving new energy efficiency pilot programs and rate recovery of demand-side management programs; (3) approving pursuit of up to three new renewable generation projects with a Georgia Power ownership interest; and (4) establishing new nuclear units as a preferred option to meet demand in the 2015/2016 timeframe (2007 IRP Order).

On August 1, 2008, Georgia Power filed with the Georgia PSC an application for the certification of Plant Vogtle Units 3 and 4 and the 2008 IRP update (Updated IRP). The application requested that the Georgia PSC take the following actions: (1) certify the proposed Plant Vogtle Units 3 and 4; (2) approve the Updated IRP; (3) allow construction work in progress in rate base for Plant Vogtle Units 3 and 4; (4) institute quarterly construction monitoring and treatment of indexed costs; (5) approve Georgia Power's recommendation to install emissions controls at Plants Branch and Yates; and (6) approve the deferral for later cost recovery of the significant expenses incurred in developing and evaluating coal-fired generation, as required by the 2007 IRP Order. The Georgia PSC is scheduled to render a decision in March 2009.

Georgia Power also filed with the Georgia PSC an application for certification to convert the coal-fired unit at Plant Mitchell to a renewable wood biomass facility which would begin service in June 2012. The Georgia PSC is scheduled to render a decision in March 2009. If certified, construction on this conversion is expected to begin in the spring of 2011.

See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction Projects - Nuclear" of Southern Company and MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Nuclear - Construction" of Georgia Power in Item 7 herein for additional information regarding the proposed Plant Vogtle Units 3 and 4.

Mississippi Base Load Construction Legislation

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor on May 9, 2008 to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest

determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. The effect of this legislation on Southern Company and Mississippi Power cannot now be determined.

On January 16, 2009, Mississippi Power filed for a Certificate of Public Convenience and Necessity with the Mississippi PSC to allow construction of a new electric generating plant located in Kemper County, Mississippi. As part of its filing, Mississippi Power has requested certain rate recovery treatment in accordance with the base load construction legislation. See MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL – "Construction Projects – Integrated Coal Gasification Combined Cycle" and "Integrated Coal Gasification Combined Cycle" of Southern Company and Mississippi Power, respectively, in Item 7 herein for additional information.

Employee Relations

The Southern Company system had a total of 27,276 employees on its payroll at December 31, 2008.

	Employees at December 31, 2008
Alabama Power	6,997
Georgia Power*	9,337
Gulf Power	1,342
Mississippi Power	1,317
SCS	4,536
Southern Holdings**	-
Southern Nuclear	3,346
Southern Power***	-
Other	401
Total	27,276

* Georgia Power has initiated a voluntary attrition plan under which participating employees may elect to resign from their positions as of March 31, 2009. Approximately 700 employees who have indicated an interest in participating in the plan have been selected by Georgia Power and are permitted to resign and receive severance. The ultimate number of employees who resign under the plan cannot be determined at this time.

** Southern Holdings has agreements with SCS whereby all employee services are rendered at cost.

*** Southern Power has no employees. Southern Power has agreements with SCS and the traditional operating companies whereby employee services are rendered at amounts in compliance with FERC regulations.

The traditional operating companies have separate agreements with local unions of the IBEW generally covering wages, working conditions, and procedures for handling grievances and arbitration. These agreements apply with certain exceptions to operating, maintenance, and construction employees.

Alabama Power has agreements with the IBEW on a five-year contract extending to August 15, 2009. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Georgia Power had an agreement with the IBEW covering wages and working conditions, which was in effect through June 30, 2008. The terms of the expired agreement are still being followed while negotiations on a new agreement are ongoing.

Gulf Power has an agreement with the IBEW covering wages and working conditions, which is in effect through October 14, 2009. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Mississippi Power has an agreement with the IBEW covering wages and working conditions, which is in effect until August 16, 2010. Upon notice given at least 60 days prior to that date, negotiations may be initiated with respect to agreement terms to be effective after such date.

Southern Nuclear and the IBEW continue in negotiations to ratify a new labor agreement for certain employees at Plants Hatch and Vogtle. The three-year agreement that was set to expire on June 30, 2008 was extended for one year and remains in full effect. A three-year agreement with the IBEW representing certain employees at Plant Farley is in effect through August 15, 2009. Upon notice given at least 60 days prior to August 15, 2009, negotiations may be initiated with respect to a new agreement after such date.

The agreements also subject the terms of the pension plans for the companies discussed above to collective bargaining with the unions at either a five-year or a 10-year cycle, depending upon union and company actions.

Item 1A. RISK FACTORS

In addition to the other information in this Form 10-K, including MANAGEMENT'S DISCUSSION AND ANALYSIS – FUTURE EARNINGS POTENTIAL in Item 7 of each registrant, and other documents filed by Southern Company and/or its subsidiaries with the SEC from time to time, the following factors should be carefully considered in evaluating Southern Company and its subsidiaries. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by, or on behalf of, Southern Company and/or its subsidiaries.

Risks Related to the Energy Industry

Southern Company and its subsidiaries are subject to substantial governmental regulation. Compliance with current and future regulatory requirements and procurement of necessary approvals, permits, and certificates may result in substantial costs to Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, are subject to substantial regulation from federal, state, and local regulatory agencies. Southern Company and its subsidiaries are required to comply with numerous laws and regulations and to obtain numerous permits, approvals, and certificates from the governmental agencies that regulate various aspects of their businesses, including customer rates, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices, and the operation of fossil-fuel, hydroelectric, and nuclear generating facilities. For example, the rates charged to wholesale customers by the traditional operating companies and by Southern Power must be approved by the FERC and failure to maintain FERC market-based rate authority may impact the rates charged to wholesale customers. Additionally, the respective state PSCs must approve the traditional operating companies' rates for retail customers. While the retail rates approved by the respective state PSCs are designed to provide for recovery of costs and a return on invested capital, there can be no assurance that a state PSC will not deem certain costs to be imprudently incurred and not subject to recovery.

Southern Company and its subsidiaries believe the necessary permits, approvals, and certificates have been obtained for their respective existing operations and that their respective businesses are conducted in accordance with applicable laws; however, the impact of any future revision or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to Southern Company or any of its subsidiaries cannot now be predicted. Changes in regulation or the imposition of additional regulations could influence the operating environment of Southern Company and its subsidiaries and may result in substantial costs.

Risks Related to Environmental and Climate Change Legislation and Regulation

Southern Company's and the traditional operating companies' costs of compliance with environmental laws are significant. The costs of compliance with future environmental laws, including laws and regulations designed to address global climate change and renewable energy standards, and the incurrence of environmental liabilities could affect unit retirement decisions and negatively impact the net income, cash flows, and financial condition of Southern Company, the traditional operating companies, or Southern Power.

Southern Company, the traditional operating companies, and Southern Power are subject to extensive federal, state, and local environmental requirements which, among other things, regulate air emissions, water usage and discharges, and the management of hazardous and solid waste in order to adequately protect the environment. Compliance with these legal requirements requires Southern Company, the traditional operating companies, and Southern Power to commit significant expenditures for installation of pollution control equipment, environmental monitoring, emissions fees, and permits at all of their respective facilities. These expenditures are significant and Southern Company, the traditional operating companies, and Southern Power expect that they will increase in the future. Through 2008, Southern Company had invested approximately $6.3 billion in capital projects to comply with these requirements, with annual totals of $1.6 billion, $1.5 billion, and $661 million for 2008, 2007, and 2006, respectively. Southern Company expects that capital expenditures to assure compliance with existing and new statutes and regulations will be an additional $1.4 billion, $737 million, and $871 million for 2009, 2010, and 2011, respectively. Because Southern Company's compliance strategy is impacted by changes to existing environmental

laws, statutes, and regulations, the cost, availability, and existing inventory of emission allowances, and Southern Company's fuel mix, the ultimate outcome cannot be determined at this time.

If Southern Company, any traditional operating company, or Southern Power fails to comply with environmental laws and regulations, even if caused by factors beyond its control, that failure may result in the assessment of civil or criminal penalties and fines. The EPA has filed civil actions against Alabama Power and Georgia Power alleging violations of the new source review provisions of the Clean Air Act. Southern Company is a party to suits alleging emissions of carbon dioxide, a greenhouse gas, contribute to global warming. An adverse outcome in any of these cases could require substantial capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect unit retirement and replacement decisions, and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent.

Existing environmental laws and regulations may be revised or new laws and regulations related to global climate change, air quality, combustion byproducts, including coal ash, or other environmental and health concerns may be adopted or become applicable to Southern Company, the traditional operating companies, and Southern Power. For example, federal legislative proposals that would impose mandatory requirements on greenhouse gas emissions and renewable energy standards continue to be strongly considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. In addition, some states, including Florida, are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. In 2007, the U. S. Supreme Court ruled that the EPA has authority to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that will follow from this response may have implications for both new and existing stationary sources, such as power plants.

New or revised laws and regulations or new interpretations of existing laws and regulations, such as those related to climate change, could affect unit retirement and replacement decisions and/or result in significant additional expense and operating restrictions on the facilities of the traditional operating companies or Southern Power or increased compliance costs which may not be fully recoverable from customers and would therefore reduce the net income of Southern Company, the traditional operating companies, or Southern Power. The cost impact of such legislation, regulation, or new interpretations would depend upon the specific requirements enacted and cannot be determined at this time.

General Risks Related to Operation of Southern Company's Utility Subsidiaries

The regional power market in which Southern Company and its utility subsidiaries compete may have changing transmission regulatory structures, which could affect the ownership of these assets and related revenues and expenses.

The traditional operating companies currently own and operate transmission facilities as part of a vertically integrated utility. Transmission revenues are not separated from generation and distribution revenues in their approved retail rates. Current FERC efforts that may potentially change the regulatory and/or operational structure of transmission include rules related to the standardization of generation interconnection, as well as an inquiry into, among other things, market power by vertically integrated utilities. The financial condition, net income, and cash flows of Southern Company and its utility subsidiaries could be adversely affected by future changes in the federal regulatory or operational structure of transmission.

Deregulation or restructuring in the electric industry may result in increased competition and unrecovered costs which could negatively impact the net income of Southern Company and the traditional operating companies and the value of their respective assets.

Increased competition resulting from restructuring efforts could have a significant adverse financial impact on Southern Company and the traditional operating companies. Any adoption in the territories served by the traditional

operating companies of retail competition and the unbundling of regulated energy service could have a significant adverse financial impact on Southern Company and the traditional operating companies due to an impairment of assets, a loss of retail customers, lower profit margins, an inability to recover reasonable costs, or increased costs of capital. Southern Company and the traditional operating companies cannot predict if or when they may be subject to changes in legislation or regulation, nor can Southern Company and the traditional operating companies predict the impact of these changes.

Additionally, the electric utility industry has experienced a substantial increase in competition at the wholesale level. As a result of changes in federal law and regulatory policy, competition in the wholesale electricity market has greatly increased due to a greater participation by traditional electricity suppliers, non-utility generators, IPPs, wholesale power marketers, and brokers and due to the trading of energy futures contracts on various commodities exchanges. In addition, FERC rules on transmission service are designed to facilitate competition in the wholesale market on a nationwide basis by providing greater flexibility and more choices to wholesale power customers.

Changes to the criteria used by the FERC for approval of market-based rate authority may negatively impact the traditional operating companies' and Southern Power's ability to charge market-based rates which could negatively impact the net income and cash flow of Southern Company, the traditional operating companies, and Southern Power.

Each of the traditional operating companies and Southern Power have authorization from the FERC to sell power to nonaffiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based sale to an affiliate.

In 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by any subsidiary of Southern Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the traditional operating companies and Southern Power to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $19.7 million, plus interest. Southern Company and its subsidiaries believe that there is no meritorious basis for an adverse decision in this proceeding and are vigorously defending themselves in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting

the CBR tariff subject to providing additional information. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Risks Related to Southern Company and its Business

Southern Company may be unable to meet its ongoing and future financial obligations and to pay dividends on its common stock if its subsidiaries are unable to pay upstream dividends or repay funds to Southern Company.

Southern Company is a holding company and, as such, Southern Company has no operations of its own. Substantially all of Southern Company's consolidated assets are held by subsidiaries. Southern Company's ability to meet its financial obligations and to pay dividends on its common stock is primarily dependent on the net income and cash flows of its subsidiaries and their ability to pay upstream dividends or to repay funds to Southern Company. Prior to funding Southern Company, Southern Company's subsidiaries have financial obligations that must be satisfied, including among others, debt service and preferred and preference stock dividends. Southern Company's subsidiaries are separate legal entities and have no obligation to provide Southern Company with funds for its payment obligations.

The financial performance of Southern Company and its subsidiaries may be adversely affected if they are unable to successfully operate their facilities or perform certain corporate functions.

The financial performance of Southern Company and its subsidiaries depends on the successful operation of its subsidiaries' electric generating, transmission, and distribution facilities. Operating these facilities involves many risks, including:

- operator error or failure of equipment or processes;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- terrorist attacks;
- fuel or material supply interruptions;
- compliance with mandatory reliability standards;
- information technology system failure; and
- catastrophic events such as fires, earthquakes, explosions, floods, droughts, hurricanes, pandemic health events such as an avian influenza, or other similar occurrences.

A decrease or elimination of revenues from the electric generation, transmission, or distribution facilities or an increase in the cost of operating the facilities would reduce the net income and cash flows and could adversely impact the financial condition of the affected traditional operating company or Southern Power and of Southern Company.

The traditional operating companies could be subject to higher costs and penalties as a result of mandatory reliability standards.

As a result of the Energy Policy Act of 2005, owners and operators of bulk power transmission systems, including the traditional operating companies, are subject to mandatory reliability standards enacted by the North American

Reliability Corporation and enforced by the FERC. Compliance with the mandatory reliability standards may subject the traditional operating companies and Southern Company to higher operating costs and may result in increased capital expenditures. If any traditional operating company is found to be in noncompliance with the mandatory reliability standards, the traditional operating company could be subject to sanctions, including substantial monetary penalties.

The revenues of Southern Company, the traditional operating companies, and Southern Power depend in part on sales under PPAs. The failure of a counterparty to one of these PPAs to perform its obligations, or the failure to renew the PPAs, could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company.

Most of Southern Power's generating capacity has been sold to purchasers under PPAs. In addition, the traditional operating companies enter into PPAs with non-affiliated parties. Revenues are dependent on the continued performance by the purchasers of their obligations under these PPAs. Even though Southern Power and the traditional operating companies have a rigorous credit evaluation process, the failure of one of the purchasers to perform its obligations could have a negative impact on the net income and cash flows of the affected traditional operating company or Southern Power and of Southern Company. Although these credit evaluations take into account the possibility of default by a purchaser, actual exposure to a default by a purchaser may be greater than the credit evaluation predicts. Additionally, neither Southern Power nor any traditional operating company can predict whether the PPAs will be renewed at the end of their respective terms or on what terms any renewals may be made. If a PPA is not renewed, a replacement PPA cannot be assured.

Southern Company, the traditional operating companies, and Southern Power may incur additional costs or delays in the construction of new plants or other facilities and may not be able to recover their investment. The facilities of the traditional operating companies and Southern Power require ongoing capital expenditures.

The businesses of the registrants require substantial capital expenditures for investments in new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards. Certain of the traditional operating companies and Southern Power are in the process of constructing new generating facilities and adding environmental controls equipment at existing generating facilities. Southern Company intends to continue its strategy of developing and constructing other new facilities, including proposed new nuclear generating units and a proposed integrated coal gasification combined cycle facility, expanding existing facilities, and adding environmental control equipment. These types of projects are long-term in nature and may involve facility designs that have not been finalized or previously constructed. The completion of these types of projects without delays or cost overruns is subject to substantial risks, including:

- shortages and inconsistent quality of equipment, materials, and labor;
- work stoppages;
- contractor or supplier non-performance under construction or other agreements;
- delays in or failure to receive necessary permits, approvals, and other regulatory authorizations;
- impacts of new and existing laws and regulations, including environmental laws and regulations;
- adverse weather conditions;
- unforeseen engineering problems;
- changes in project design or scope;
- environmental and geological conditions;

- delays or increased costs to interconnect facilities to transmission grids;
- unanticipated cost increases, including materials and labor; and
- attention to other projects.

If a traditional operating company or Southern Power is unable to complete the development or construction of a facility or decides to delay or cancel construction of a facility, it may not be able to recover its investment in that facility and may incur substantial cancellation payments under equipment purchase orders or construction contracts. Even if a construction project is completed, the total costs may be higher than estimated and there is no assurance that the traditional operating company will be able to recover such expenditures through regulated rates. In addition, construction delays and contractor performance shortfalls can result in the loss of revenues and may, in turn, adversely affect the net income and financial position of a traditional operating company or Southern Power and of Southern Company. Furthermore, if construction projects are not completed according to specification, a traditional operating company or Southern Power and Southern Company may incur liabilities and suffer reduced plant efficiency, higher operating costs, and reduced net income.

Once facilities come into commercial operation, ongoing capital expenditures are required to maintain reliable levels of operation. Significant portions of the traditional operating companies' existing facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements, or to provide reliable operations.

Changes in technology may make Southern Company's electric generating facilities owned by the traditional operating companies and Southern Power less competitive.

A key element of the business model of Southern Company, the traditional operating companies, and Southern Power is that generating power at central station power plants achieves economies of scale and produces power at a competitive cost. There are distributed generation technologies that produce power, including fuel cells, microturbines, wind turbines, and solar cells. It is possible that advances in technology will reduce the cost of alternative methods of producing power to a level that is competitive with that of most central station power electric production. If this were to happen and if these technologies achieved economies of scale, the market share of Southern Company, the traditional operating companies, and Southern Power could be eroded, and the value of their respective electric generating facilities could be reduced. It is also possible that rapid advances in central station power generation technology could reduce the value of the current electric generating facilities owned by Southern Company, the traditional operating companies, and Southern Power. Changes in technology could also alter the channels through which electric customers buy or utilize power, which could reduce the revenues or increase the expenses of Southern Company, the traditional operating companies, or Southern Power.

Operation of nuclear facilities involves inherent risks, including environmental, health, regulatory, terrorism, and financial risks, that could result in fines or the closure of Southern Company's nuclear units owned by Alabama Power or Georgia Power and which may present potential exposures in excess of insurance coverage.

Alabama Power owns two nuclear units and Georgia Power holds undivided interests in, and contracts for operation of, four nuclear units. These six units are operated by Southern Nuclear and represent approximately 3,680 megawatts, or 8.6%, of Southern Company's generation capacity as of December 31, 2008. These nuclear facilities are subject to environmental, health, and financial risks such as on-site storage of spent nuclear fuel, the ability to dispose of such spent nuclear fuel, the ability to maintain adequate reserves for decommissioning, potential liabilities arising out of the operation of these facilities, and the threat of a possible terrorist attack. Alabama Power and Georgia Power maintain decommissioning trusts and external insurance coverage to minimize the financial exposure to these risks; however, it is possible that damages could exceed the amount of insurance coverage.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines

or shut down any unit, depending upon its assessment of the severity of the situation, until compliance is achieved. NRC orders or regulations related to increased security measures and any future safety requirements promulgated by the NRC could require Alabama Power and Georgia Power to make substantial operating and capital expenditures at their nuclear plants. In addition, although Alabama Power, Georgia Power, and Southern Company have no reason to anticipate a serious nuclear incident at their plants, if an incident did occur, it could result in substantial costs to Alabama Power or Georgia Power and Southern Company. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit.

In addition, potential terrorist threats and increased public scrutiny of utilities could result in increased nuclear licensing or compliance costs that are difficult or impossible to predict.

The generation operations and energy marketing operations of Southern Company, the traditional operating companies, and Southern Power are subject to risks, many of which are beyond their control, including changes in power prices and fuel costs, that may reduce Southern Company's, the traditional operating companies', and Southern Power's revenues and increase costs.

The generation operations and energy marketing operations of Southern Company, the traditional operating companies, and Southern Power are subject to changes in power prices or fuel costs, which could increase the cost of producing power or decrease the amount Southern Company, the traditional operating companies, and Southern Power receive from the sale of power. The market prices for these commodities may fluctuate significantly over relatively short periods of time. Southern Company, the traditional operating companies, and Southern Power attempt to mitigate risks associated with fluctuating fuel costs by passing these costs on to customers through the traditional operating companies' fuel cost recovery clauses or through PPAs. Among the factors that could influence power prices and fuel costs are:

- prevailing market prices for coal, natural gas, uranium, fuel oil, and other fuels used in the generation facilities of the traditional operating companies and Southern Power including associated transportation costs, and supplies of such commodities;
- demand for energy and the extent of additional supplies of energy available from current or new competitors;
- liquidity in the general wholesale electricity market;
- weather conditions impacting demand for electricity;
- seasonality;
- transmission or transportation constraints or inefficiencies;
- availability of competitively priced alternative energy sources;
- forced or unscheduled plant outages for the Southern Company system, its competitors, or third party providers;
- the financial condition of market participants;
- the economy in the service territory, the nation, and worldwide, including the impact of economic conditions on industrial and commercial demand for electricity and the worldwide demand for fuels;
- natural disasters, wars, embargos, acts of terrorism, and other catastrophic events; and
- federal, state, and foreign energy and environmental regulation and legislation.

Certain of these factors could increase the expenses of the traditional operating companies or Southern Power and

Southern Company. For the traditional operating companies, such increases may not be fully recoverable through rates. Other of these factors could reduce the revenues of the traditional operating companies or Southern Power and Southern Company.

The traditional operating companies have experienced underrecovered fuel cost balances and deficits in their storm cost recovery reserve balances and may continue to experience such balances in the future. While the traditional operating companies are generally authorized to recover underrecovered fuel costs through fuel cost recovery clauses and storm recovery costs through special rate provisions administered by the respective PSCs, recovery may be denied if costs are deemed to be imprudently incurred and delays in the authorization of such recovery could negatively impact the cash flows of the affected traditional operating company and Southern Company.

The use of derivative contracts by Southern Company and its subsidiaries in the normal course of business could result in financial losses that negatively impact the net income of Southern Company and its subsidiaries.

Southern Company and its subsidiaries, including the traditional operating companies and Southern Power, use derivative instruments, such as swaps, options, futures, and forwards, to manage their commodity and interest rate risks and, to a lesser extent, engage in limited trading activities. Southern Company and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

The traditional operating companies and Southern Power may not be able to obtain adequate fuel supplies, which could limit their ability to operate their facilities.

The traditional operating companies and Southern Power purchase fuel, including coal, natural gas, uranium, and fuel oil, from a number of suppliers. Disruption in the delivery of fuel, including disruptions as a result of, among other things, transportation delays, weather, labor relations, force majeure events, or environmental regulations affecting any of these fuel suppliers, could limit the ability of the traditional operating companies and Southern Power to operate their respective facilities, and thus reduce the net income of the affected traditional operating company or Southern Power and Southern Company.

The traditional operating companies are dependent on coal for much of their electric generating capacity. Each traditional operating company has coal supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to the traditional operating companies. The suppliers under these agreements may experience financial or technical problems which inhibit their ability to fulfill their obligations to the traditional operating companies. In addition, the suppliers under these agreements may not be required to supply coal to the traditional operating companies under certain circumstances, such as in the event of a natural disaster. If the traditional operating companies are unable to obtain their coal requirements under these contracts, the traditional operating companies may be required to purchase their coal requirements at higher prices, which may not be fully recoverable through rates.

In addition, Southern Power in particular, and the traditional operating companies to a lesser extent, are dependent on natural gas for a portion of their electric generating capacity. Natural gas supplies can be subject to disruption in the event production or distribution is curtailed, such as in the event of a hurricane.

In addition, world market conditions for fuels can impact the availability of natural gas, coal, and uranium.

Demand for power could exceed supply capacity, resulting in increased costs for purchasing capacity in the open market or building additional generation capabilities.

Through the traditional operating companies and Southern Power, Southern Company is currently obligated to supply power to retail customers and wholesale customers under long-term PPAs. At peak times, the demand for power required to meet this obligation could exceed Southern Company's available generation capacity. Market or

competitive forces may require that the traditional operating companies or Southern Power purchase capacity on the open market or build additional generation capabilities. Because regulators may not permit the traditional operating companies to pass all of these purchase or construction costs on to their customers, the traditional operating companies may not be able to recover any of these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of purchased or constructed capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's long-term fixed price PPAs, Southern Power would not have the ability to recover any of these costs. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and Southern Company.

Demand for power could decrease or fail to grow at expected rates, resulting in stagnant or reduced revenues, limited growth opportunities, and potentially stranded generation assets.

Southern Company, the traditional operating companies, and Southern Power collectively engage in a long-term planning process to determine the optimal mix and timing of new generation assets required to serve future load obligations. This planning process must look many years into the future in order to accommodate the long lead times associated with the permitting and construction of new generation facilities. Inherent risk exists in predicting demand this far into the future as these future loads are dependent on many uncertain factors, including regional economic conditions, customer usage patterns, efficiency programs, and customer technology adoption. Because regulators may not permit the traditional operating companies to adjust rates to recover the costs of new generation assets while such assets are being constructed, the traditional operating companies may not be able to fully recover these costs or may have exposure to regulatory lag associated with the time between the incurrence of costs of additional capacity and the traditional operating companies' recovery in customers' rates. Under Southern Power's model of selling capacity and energy at negotiated market-based rates under long-term PPAs, Southern Power might not be able to fully execute its business plan if market prices drop below original forecasts. Southern Power may not be able to extend its existing PPAs or to find new buyers for existing generation assets as existing PPAs expire, or it may be forced to market these assets at prices lower than originally intended. These situations could have negative impacts on net income and cash flows for the affected traditional operating company or Southern Power and Southern Company.

The operating results of Southern Company, the traditional operating companies, and Southern Power are affected by weather conditions and may fluctuate on a seasonal and quarterly basis.

Electric power supply is generally a seasonal business. In many parts of the country, demand for power peaks during the summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, the overall operating results of Southern Company, the traditional operating companies, and Southern Power in the future may fluctuate substantially on a seasonal basis. In addition, Southern Company, the traditional operating companies, and Southern Power have historically sold less power when weather conditions are milder. Unusually mild weather in the future could reduce the revenues, net income, available cash, and borrowing ability of Southern Company, the traditional operating companies, and Southern Power.

Mirant and The Official Committee of Unsecured Creditors of Mirant Corporation have filed a claim against Southern Company seeking substantial monetary damages in connection with transfers made by Mirant to Southern Company prior to the Mirant spin-off. An adverse outcome of this litigation could negatively impact the net income and cash flows of Southern Company.

Mirant was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and selected other countries. It was a wholly-owned subsidiary of Southern Company until its initial public offering in October 2000. In April 2001, Southern Company completed a spin-off to its shareholders of its remaining ownership, and Mirant became an independent corporate entity.

In July 2003, Mirant and certain of its affiliates filed for voluntary reorganization under Chapter 11 of the Bankruptcy Code. In January 2006, Mirant's plan of reorganization became effective, and Mirant emerged from bankruptcy. As part of the plan, Mirant transferred substantially all of its assets and its restructured debt to a new corporation that adopted the name Mirant Corporation (Reorganized Mirant).

In December 2004, as a result of concluding an IRS audit for the tax years 2000 and 2001, Southern Company paid approximately $39 million in additional tax and interest related to Mirant tax items and filed a claim in Mirant's bankruptcy case for that amount. Through December 2008, Southern Company received from the IRS approximately $38 million in refunds related to Mirant. Southern Company believes it has a right to recoup the $39 million tax payment owed by Mirant from such tax refunds. As a result, Southern Company intends to retain the tax refunds and reduce its claim against Mirant for the payment of Mirant taxes by the amount of such refunds. MC Asset Recovery, a special purpose subsidiary of Reorganized Mirant, has objected to and sought to equitably subordinate the Southern Company tax claim in its fraudulent transfer litigation against Southern Company. Southern Company has reserved the remaining amount with respect to its Mirant tax claim.

If Southern Company is ultimately required to make any additional payments either with respect to the IRS audit or its contingent obligations under guarantees of Mirant subsidiaries, Mirant's indemnification obligation to Southern Company for these additional payments, if allowed, would constitute unsecured claims against Mirant, entitled to stock in Reorganized Mirant. The final outcome of this matter cannot now be determined.

In June 2005, Mirant, as a debtor in possession, and The Official Committee of Unsecured Creditors of Mirant Corporation filed a complaint against Southern Company in the U.S. Bankruptcy Court for the Northern District of Texas, which was amended in July 2005, February 2006, May 2006, and March 2007. In January 2006, MC Asset Recovery was substituted as plaintiff. The fourth amended complaint (the complaint) alleges that Southern Company caused Mirant to engage in certain fraudulent transfers and to pay illegal dividends to Southern Company prior to the spin-off. The complaint also seeks to recharacterize certain advances from Southern Company to Mirant for investments in energy facilities from debt to equity. The complaint further alleges that Southern Company is liable to Mirant's creditors for the full amount of Mirant's liability under an alter ego theory of recovery and that Southern Company breached its fiduciary duties to Mirant and its creditors, caused Mirant to breach its fiduciary duties to creditors, and aided and abetted breaches of fiduciary duties by Mirant's directors and officers. The complaint also seeks recoveries under the theories of restitution and unjust enrichment. In addition, the complaint alleged a claim under the Federal Debt Collection Procedure Act (FDCPA) to avoid certain transfers from Mirant to Southern Company; however, on July 7, 2008, the court ruled that the FDCPA does not apply and that Georgia law should apply instead. The complaint seeks monetary damages in excess of $2 billion plus interest, punitive damages, attorneys' fees, and costs. Finally, the complaint includes an objection to Southern Company's pending claims against Mirant in the Bankruptcy Court (which relate to reimbursement under the separation agreements of payments such as income taxes, interest, legal fees, and other guarantees described in Note 7 to the financial statements of Southern Company in Item 8 herein) and seeks equitable subordination of Southern Company's claims to the claims of all other creditors. Southern Company served an answer to the complaint in April 2007.

In February 2006, the Company's motion to transfer the case to the U.S. District Court for the Northern District of Georgia was granted. In May 2006, Southern Company filed a motion for summary judgment seeking entry of judgment against the plaintiff as to all counts in the complaint. In December 2006, the U.S. District Court for the Northern District of Georgia granted in part and denied in part the motion. As a result, certain breach of fiduciary duty claims alleged in earlier versions of the complaint were barred; all other claims were allowed to proceed. On August 6, 2008, Southern Company filed a second motion for summary judgment. MC Asset Recovery filed its response to Southern Company's motion for summary judgment on October 20, 2008. On February 5, 2009, the court denied Southern Company's summary judgment motion in connection with the fraudulent conveyance and illegal dividend claims concerning certain advance return/loan repayments in 1999, dividends in 1999 and 2000, and transfers in connection with Mirant's separation from Southern Company. The court granted the motion with respect to certain claims, including claims for restitution and unjust enrichment, claims that Southern Company aided and abetted Mirant's directors' breach of fiduciary duties to Mirant, and claims that Southern Company used Mirant as an alter ego. In addition, the court granted Southern Company's motion in connection with the fraudulent transfer and illegal dividend claims concerning certain turbine termination payments. Southern Company believes there is no meritorious basis for the claims in the complaint and is vigorously defending itself in this action. See Note 3 to the financial statements of Southern Company under "Mirant Matters – MC Asset Recovery Litigation" in Item 8 herein. The ultimate outcome of these matters cannot now be determined at this time.

Risks Related to Market and Economic Volatility

The business of Southern Company, the traditional operating companies, and Southern Power is dependent on their ability to successfully access funds through capital markets and financial institutions. The inability of Southern Company, any traditional operating company, or Southern Power to access funds may limit its ability to execute its business plan by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows.

Southern Company, the traditional operating companies, and Southern Power rely on access to both short-term money markets and longer-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from their respective operations. If Southern Company, any traditional operating company, or Southern Power is not able to access capital at competitive rates, its ability to implement its business plan will be limited by impacting its ability to fund capital investments or acquisitions that Southern Company, the traditional operating companies, or Southern Power may otherwise rely on to achieve future earnings and cash flows. In addition, Southern Company, the traditional operating companies, and Southern Power rely on committed bank lending agreements as back-up liquidity which allows them to access low cost money markets. Each of Southern Company, the traditional operating companies, and Southern Power believes that it will maintain sufficient access to these financial markets based upon current credit ratings. However, certain market disruptions or a downgrade of the credit rating of Southern Company, any traditional operating company, or Southern Power may increase its cost of borrowing, adversely affect its ability to raise capital through the issuance of securities or other borrowing arrangements or its ability to secure committed bank lending agreements used as back-up sources of capital. Such disruptions could include:

- an economic downturn or uncertainty;
- the bankruptcy of an unrelated energy company or financial institution;
- capital markets volatility and interruption;
- financial institution distress;
- market prices for electricity and gas;
- terrorist attacks or threatened attacks on Southern Company's facilities or unrelated energy companies' facilities;
- war or threat of war; or
- the overall health of the utility and financial institution industries.

Market performance and other changes may decrease the value of benefit plans and decommissioning trust assets, which then could require significant additional funding.

The performance of the capital markets affects the values of the assets held in trust under Southern Company's pension and postretirement benefit plans and the assets held in trust to satisfy obligations to decommission Alabama Power's and Georgia Power's nuclear plants. Southern Company, Alabama Power, and Georgia Power have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below projected return rates. A decline in the market value of these assets, as has been experienced in prior periods, may increase the funding requirements relating to Southern Company's benefit plan liabilities and Alabama Power's and Georgia Power's decommissioning obligations. Additionally, changes in interest rates affect the liabilities under Southern Company's pension and postretirement benefit plans; as interest rates decrease, the liabilities increase, potentially requiring additional funding. Further, changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase the funding requirements of the obligations related to the pension benefit plans. If Southern Company is unable to successfully manage benefit plan assets and Alabama Power and Georgia

Power are unable to successfully manage the decommissioning trust funds, results of operations and financial position could be negatively affected.

Southern Company, the traditional operating companies, and Southern Power are subject to risks associated with a changing economic environment, which could impact their ability to obtain adequate insurance and the financial stability of the customers of the traditional operating companies and Southern Power.

The financial condition of some insurance companies, the threat of terrorism, and the hurricanes that affected the Gulf Coast, among other things, have had disruptive effects on the insurance industry. The availability of insurance covering risks that Southern Company, the traditional operating companies, Southern Power, and their respective competitors typically insure against may decrease, and the insurance that Southern Company, the traditional operating companies, and Southern Power are able to obtain may have higher deductibles, higher premiums, and more restrictive policy terms. Additionally, any economic downturn or disruption of financial markets could negatively affect the financial stability of the customers and counterparties of the traditional operating companies and Southern Power. These factors could adversely affect Southern Company's subsidiaries' ability to maintain energy sales, thereby decreasing Southern Company's level of future net income.

Certain of the traditional operating companies have substantial investments in the Atlantic or Gulf Coast regions which can be subject to major storm activity. The ability of the traditional operating companies to recover costs and replenish reserves in the event of a major storm, other natural disaster, terrorist attack, or other catastrophic event generally will require regulatory action.

Each traditional operating company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generating facilities and other property. In the event a traditional operating company experiences a natural disaster, terrorist attack, or other catastrophic event, recovery of costs in excess of reserves and insurance coverage is subject to the approval of its state PSC. While the traditional operating companies generally are entitled to recover prudently incurred costs incurred in connection with such an event, any denial by the applicable state PSC or delay in recovery of any portion of such costs could have a material negative impact on a traditional operating company's and Southern Company's results of operations and/or cash flows.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES

Electric Properties – The Electric Utilities

The traditional operating companies, Southern Power, and SEGCO, at December 31, 2008, owned and/or operated 34 hydroelectric generating stations, 34 fossil fuel generating stations, three nuclear generating stations, and 12 combined cycle/cogeneration stations. The amounts of capacity for each company are shown in the table below.

Generating Station	Location	Nameplate Capacity (1) (Kilowatts)
FOSSIL STEAM		
Gadsden	Gadsden, AL	120,000
Gorgas	Jasper, AL	1,221,250
Barry	Mobile, AL	1,525,000
Greene County	Demopolis, AL	300,000 (2)
Gaston Unit 5	Wilsonville, AL	880,000
Miller	Birmingham, AL	2,532,288 (3)
Alabama Power Total		6,578,538
Bowen	Cartersville, GA	3,160,000
Branch	Milledgeville, GA	1,539,700
Hammond	Rome, GA	800,000
Kraft	Port Wentworth, GA	281,136
McDonough	Atlanta, GA	490,000
McIntosh	Effingham County, GA	163,117
McManus	Brunswick, GA	115,000
Mitchell	Albany, GA	125,000
Scherer	Macon, GA	750,924 (4)
Wansley	Carrollton, GA	925,550 (5)
Yates	Newnan, GA	1,250,000
Georgia Power Total		9,600,427
Crist	Pensacola, FL	970,000
Daniel	Pascagoula, MS	500,000 (6)
Lansing Smith	Panama City, FL	305,000
Scholz	Chattahoochee, FL	80,000
Scherer Unit 3	Macon, GA	204,500 (4)
Gulf Power Total		2,059,500
Daniel	Pascagoula, MS	500,000 (6)
Eaton	Hattiesburg, MS	67,500
Greene County	Demopolis, AL	200,000 (2)
Sweatt	Meridian, MS	80,000
Watson	Gulfport, MS	1,012,000
Mississippi Power Total		1,859,500
Gaston Units 1-4	Wilsonville, AL	
SEGCO Total		1,000,000 (7)
Total Fossil Steam		21,097,965

Generating Station	Location	Nameplate Capacity (1) (Kilowatts)
NUCLEAR STEAM		
Farley	Dothan, AL	
Alabama Power Total		1,720,000
Hatch	Baxley, GA	899,612 (8)
Vogtle	Augusta, GA	1,060,240 (9)
Georgia Power Total		1,959,852
Total Nuclear Steam		3,679,852
COMBUSTION TURBINES		
Greene County	Demopolis, AL	
Alabama Power Total		720,000
Boulevard	Savannah, GA	59,100
Bowen	Cartersville, GA	39,400
Intercession City	Intercession City, FL	47,667 (10)
Kraft	Port Wentworth, GA	22,000
McDonough	Atlanta, GA	78,800
McIntosh Units 1 through 8	Effingham County, GA	640,000
McManus	Brunswick, GA	481,700
Mitchell	Albany, GA	118,200
Robins	Warner Robins, GA	158,400
Wansley	Carrollton, GA	26,322
Wilson	Augusta, GA	354,100
Georgia Power Total		2,025,689
Lansing Smith Unit A	Panama City, FL	39,400
Pea Ridge Units 1-3	Pea Ridge, FL	15,000
Gulf Power Total		54,400
Chevron Cogenerating Station	Pascagoula, MS	147,292 (11)
Sweatt	Meridian, MS	39,400

Generating Station	Location	Nameplate Capacity (1)
		(Kilowatts)
Watson	Gulfport, MS	39,360
Mississippi Power Total		226,052
Dahlberg	Jackson County, GA	756,000
DeSoto	Arcadia, FL	343,760
Oleander	Cocoa, FL	791,301
Rowan	Salisbury, NC	455,250
Southern Power Total		2,346,311
Gaston **(SEGCO)**	Wilsonville, AL	19,680 (7)
Total Combustion Turbines		5,392,132
COGENERATION		
Washington County	Washington County, AL	123,428
GE Plastics Project	Burkeville, AL	104,800
Theodore	Theodore, AL	236,418
Total Cogeneration		464,646
COMBINED CYCLE		
Barry	Mobile, AL	
Alabama Power Total		1,070,424
McIntosh Units 10&11	Effingham County, GA	
Georgia Power Total		1,318,920
Smith	Lynn Haven, FL	
Gulf Power Total		545,500
Daniel (Leased)	Pascagoula, MS	
Mississippi Power Total		1,070,424
Franklin	Smiths, AL	1,857,820
Harris	Autaugaville, AL	1,318,920
Rowan	Salisbury, NC	530,550
Stanton Unit A	Orlando, FL	428,649 (12)
Wansley	Carrollton, GA	1,073,000
Southern Power Total		5,208,939
Total Combined Cycle		9,214,207
HYDROELECTRIC FACILITIES		
Bankhead	Holt, AL	53,985
Bouldin	Wetumpka, AL	225,000
Harris	Wedowee, AL	132,000
Henry	Ohatchee, AL	72,900
Holt	Holt, AL	46,944
Jordan	Wetumpka, AL	100,000
Lay	Clanton, AL	177,000
Lewis Smith	Jasper, AL	157,500
Logan Martin	Vincent, AL	135,000
Martin	Dadeville, AL	182,000
Mitchell	Verbena, AL	170,000
Thurlow	Tallassee, AL	81,000
Weiss	Leesburg, AL	87,750
Yates	Tallassee, AL	47,000
Alabama Power Total		1,668,079
Barnett Shoals (Leased)	Athens, GA	2,800
Bartletts Ferry	Columbus, GA	173,000
Goat Rock	Columbus, GA	38,600
Lloyd Shoals	Jackson, GA	14,400
Morgan Falls	Atlanta, GA	16,800
North Highlands	Columbus, GA	29,600
Oliver Dam	Columbus, GA	60,000
Rocky Mountain	Rome, GA	215,256 (13)
Sinclair Dam	Milledgeville, GA	45,000
Tallulah Falls	Clayton, GA	72,000
Terrora	Clayton, GA	16,000
Tugalo	Clayton, GA	45,000
Wallace Dam	Eatonton, GA	321,300
Yonah	Toccoa, GA	22,500
6 Other Plants		18,080
Georgia Power Total		1,090,336
Total Hydroelectric Facilities		2,758,415
Total Generating Capacity		42,607,217

Notes:

(1) See "Jointly-Owned Facilities" herein for additional information.

(2) Owned by Alabama Power and Mississippi Power as tenants in common in the proportions of 60% and 40%, respectively.

(3) Capacity shown is Alabama Power's portion (91.84%) of total plant capacity.

(4) Capacity shown for Georgia Power is 8.4% of Units 1 and 2 and 75% of Unit 3. Capacity shown for Gulf Power is 25% of Unit 3.

(5) Capacity shown is Georgia Power's portion (53.5%) of total plant capacity.

(6) Represents 50% of the plant which is owned as tenants in common by Gulf Power and Mississippi Power.

(7) SEGCO is jointly-owned by Alabama Power and Georgia Power. See BUSINESS in Item 1 herein for additional information.

(8) Capacity shown is Georgia Power's portion (50.1%) of total plant capacity.

(9) Capacity shown is Georgia Power's portion (45.7%) of total plant capacity.

(10) Capacity shown represents 33 1/3% of total plant capacity. Georgia Power owns a 1/3 interest in the unit with 100% use of the unit from June through September. Progress Energy Florida operates the unit.

(11) Generation is dedicated to a single industrial customer.

(12) Capacity shown is Southern Power's portion (65%) of total plant capacity.

(13) Capacity shown is Georgia Power's portion (25.4%) of total plant capacity. OPC operates the plant.

Except as discussed below under "Titles to Property," the principal plants and other important units of the traditional operating companies, Southern Power, and SEGCO are owned in fee by the respective companies. It is the opinion of management of each such company that its operating properties are adequately maintained and are substantially in good operating condition.

Mississippi Power owns a 79-mile length of 500-kilovolt transmission line which is leased to Entergy Gulf States. The line, completed in 1984, extends from Plant Daniel to the Louisiana state line. Entergy Gulf States is paying a use fee over a 40-year period covering all expenses and the amortization of the original $57 million cost of the line. At December 31, 2008, the unamortized portion of this cost was approximately $23 million.

In 2008, the maximum demand on the traditional operating companies, Southern Power, and SEGCO was 37,166,000 kilowatts and occurred on August 6, 2008. The all-time maximum demand of 38,777,000 kilowatts on the traditional operating companies, Southern Power, and SEGCO occurred on August 22, 2007. These amounts exclude demand served by capacity retained by MEAG, OPC, and SEPA. The reserve margin for the traditional operating companies, Southern Power, and SEGCO in 2008 was 15.3%. See SELECTED FINANCIAL DATA in Item 6 herein for additional information on peak demands.

Jointly-Owned Facilities

Alabama Power, Georgia Power, and Southern Power have undivided interests in certain generating plants and other related facilities to or from non-affiliated parties. The percentages of ownership are as follows:

		Percentage Ownership										
	Total Capacity	Alabama Power	Power South	Georgia Power	OPC	MEAG	Dalton	Progress Energy Florida	Southern Power	OUC	FMPA	KUA
	(Megawatts)											
Plant Miller Units 1 and 2	1,320	91.8%	8.2%	–%	–%	–%	–%	–%	–%	–%	–%	–%
Plant Hatch	1,796	–	–	50.1	30.0	17.7	2.2	–	–	–	–	–
Plant Vogtle	2,320	–	–	45.7	30.0	22.7	1.6	–	–	–	–	–
Plant Scherer Units 1 and 2	1,636	–	–	8.4	60.0	30.2	1.4	–	–	–	–	–
Plant Wansley	1,779	–	–	53.5	30.0	15.1	1.4	–	–	–	–	–
Rocky Mountain	848	–	–	25.4	74.6	–	–	–	–	–	–	–
Intercession City, FL	143	–	–	33.3	–	–	–	66.7	–	–	–	–
Plant Stanton A	660	–	–	–	–	–	–	–	65%	28%	3.5%	3.5%

Alabama Power and Georgia Power have contracted to operate and maintain the respective units in which each has an interest (other than Rocky Mountain and Intercession City) as agent for the joint owners. SCS provides operation and maintenance services for Plant Stanton A.

In addition, Georgia Power has commitments regarding a portion of a five percent interest in Plant Vogtle owned by MEAG that are in effect until the later of retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest. The payments for capacity are required whether any capacity is available. The energy cost is a function of each unit's variable operating costs. Except for the portion of the capacity payments related to the Georgia PSC's disallowances of Plant Vogtle costs, the cost of such capacity and energy is included in purchased power from non-affiliates in Georgia Power's statements of income in Item 8 herein.

Titles to Property

The traditional operating companies', Southern Power's, and SEGCO's interests in the principal plants (other than certain pollution control facilities, one small hydroelectric generating station leased by Georgia Power, combined cycle units at Plant Daniel leased by Mississippi Power, and the land on which five combustion turbine generators of Mississippi Power are located, which is held by easement) and other important units of the respective companies are owned in fee by such companies, subject only to the liens pursuant to pollution control revenue bonds of Alabama Power and Gulf Power on specific pollution control facilities. See Note 6 to the financial statements of Southern Company, Alabama Power, and Gulf Power under "Assets Subject to Lien" and Note 7 to the financial statements of Mississippi Power under "Operating Leases – Plant Daniel Combined Cycle Generating Units" in Item 8 herein for additional information. The traditional operating companies own the fee interests in certain of their principal plants as tenants in common. See "Jointly-Owned Facilities" herein for additional information. Properties such as electric transmission and distribution lines and steam heating mains are constructed principally on rights-of-way which are maintained under franchise or are held by easement only. A substantial portion of lands submerged by reservoirs is held under flood right easements.

Item 3. LEGAL PROCEEDINGS

(1) United States of America v. Alabama Power (United States District Court for the Northern District of Alabama)

United States of America v. Georgia Power (United States District Court for the Northern District of Georgia)

See Note 3 to the financial statements of Southern Company and each traditional operating company under "Environmental Matters – New Source Review Actions" in Item 8 herein for information.

(2) Environmental Remediation

See Note 3 to the financial statements of Southern Company, Georgia Power, Gulf Power, and Mississippi Power under "Environmental Matters – Environmental Remediation" and Note 3 to the financial statements of Mississippi Power under "Retail Regulatory Matters – Environmental Compliance Overview Plan" in Item 8 herein for information related to environmental remediation.

(3) In re: Mirant Corporation, et al. (United States Bankruptcy Court for the Northern District of Texas)

See Note 3 to the financial statements of Southern Company under "Mirant Matters – Mirant Bankruptcy" in Item 8 herein for information.

(4) MC Asset Recovery, LLC v. Southern Company (United States District Court for the Northern District of Georgia) (formerly styled *In re: Mirant Corporation, et al.* in the United States Bankruptcy Court for the Northern District of Texas)

See Note 3 to the financial statements of Southern Company under "Mirant Matters – MC Asset Recovery Litigation" in Item 8 herein for information.

(5) In re: Mirant Corporation Securities Litigation (United States District Court for the Northern District of Georgia)

See Note 3 to the financial statements of Southern Company under "Mirant Matters – Mirant Securities Litigation" in Item 8 herein for information.

(6) Right of Way Litigation

See Note 3 to the financial statements of Southern Company and Mississippi Power under "Right of Way Litigation" in Item 8 herein for information.

See Note 3 to the financial statements of each registrant in Item 8 herein for descriptions of additional legal and administrative proceedings discussed therein.

Item 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS.

Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power

None.

EXECUTIVE OFFICERS OF SOUTHERN COMPANY

(Identification of executive officers of Southern Company is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2008.

David M. Ratcliffe
Chairman, President, Chief Executive Officer, and Director
Age 60
Elected in 1999. President since April 2004; Chairman and Chief Executive Officer since July 2004. Previously served as Chief Executive Officer of Georgia Power from June 1999 to April 2004.

W. Paul Bowers
Executive Vice President and Chief Financial Officer
Age 52
Elected in 2001. Executive Vice President and Chief Financial Officer since February 2008 and Executive Vice President since May 2007. Previously served as President of Southern Company Generation, a business unit of Southern Company, and Executive Vice President of SCS from May 2001 through January 2008; and President and Chief Executive Officer of Southern Power from May 2001 through March 2005.

Thomas A. Fanning
Executive Vice President and Chief Operating Officer
Age 51
Elected in 2003. Executive Vice President and Chief Operating Officer since February 2008. Previously served as Executive Vice President and Chief Financial Officer from May 2007 through January 2008 and Executive Vice President, Chief Financial Officer, and Treasurer from April 2003 to May 2007.

Michael D. Garrett
Executive Vice President
Age 59
Elected in 2004. Executive Vice President since January 2004. He also serves as President and Director of Georgia Power since January 2004 and Chief Executive Officer of Georgia Power since April 2004.

G. Edison Holland, Jr.
Executive Vice President, General Counsel, and Secretary
Age 56
Elected in 2001. Executive Vice President and General Counsel since April 2001.

C. Alan Martin
President and Chief Executive Officer of SCS
Age 60
Elected in 2008. President and Chief Executive Officer of SCS since February 2008. Previously served as Executive Vice President of the Customer Service Organization at Alabama Power from May 2001 through January 2008.

Charles D. McCrary
Executive Vice President
Age 57
Elected in 1998. Executive Vice President of Southern Company since February 2002; President, Chief Executive Officer, and Director of Alabama Power since October 2001.

James H. Miller, III
President and Chief Executive Officer of Southern Nuclear
Age 59
Elected in 2008. President and Chief Executive Officer of Southern Nuclear since August 27, 2008. Previously served as Senior Vice President and General Counsel of Georgia Power from March 2004 through August 2008 and Vice President and Associate General Counsel for SCS and Senior Vice President, General Counsel, and Assistant Secretary of Southern Power from August 2001 through February 2004.

Christopher C. Womack
Executive Vice President
Age 50
Elected in 2008. Executive Vice President and President of External Affairs since January 1, 2009. Previously served as Executive Vice President of External Affairs of Georgia Power from March 2006 through December 2008 and Senior Vice President of Fossil and Hydro Generation and Senior Production Officer of Georgia Power from December 2001 to February 2006.

The officers of Southern Company were elected for a term running from the first meeting of the directors following the last annual meeting (May 28, 2008) for one year until the first board meeting after the next annual meeting or until their successors are elected and have qualified, except for Mr. Miller whose election was effective on August 27, 2008 and Mr. Womack whose election was effective on January 1, 2009.

EXECUTIVE OFFICERS OF ALABAMA POWER

(Identification of executive officers of Alabama Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2008.

Charles D. McCrary
President, Chief Executive Officer, and Director
Age 57
Elected in 2001. President, Chief Executive Officer, and Director since October 2001; Executive Vice President of Southern Company since February 2002.

Art P. Beattie
Executive Vice President, Chief Financial Officer, and Treasurer
Age 54
Elected in 2004. Executive Vice President, Chief Financial Officer, and Treasurer since February 2005. Previously served as Vice President and Comptroller of Alabama Power from 1998 through January 2005.

Mark A. Crosswhite
Executive Vice President
Age 46
Elected in 2008. Executive Vice President of External Affairs since February 1, 2008. Previously served as Senior Vice President and Counsel of Alabama Power from July 2006 through January 2008; Senior Vice President, General Counsel, and Assistant Secretary of Southern Power from March 2004 through January 2005; and Vice President of SCS from March 2004 through January 2008.

Steven R. Spencer
Executive Vice President
Age 53
Elected in 2001. Executive Vice President of the Customer Service Organization since February 1, 2008. Previously served as Executive Vice President of External Affairs from 2001 through January 2008.

Jerry L. Stewart
Senior Vice President
Age 59
Elected in 1999. Senior Vice President of Fossil and Hydro Generation since 1999.

The officers of Alabama Power were elected for a term running from the last annual organizational meeting of the directors (April 25, 2008) for one year until the next annual meeting or until their successors are elected and have qualified.

EXECUTIVE OFFICERS OF GEORGIA POWER

(Identification of executive officers of Georgia Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2008.

Michael D. Garrett
President, Chief Executive Officer, and Director
Age 59
Elected in 2003. President, Chief Executive Officer, and Director of Georgia Power since April 2004. Previously served as President and Director of Georgia Power from January 2004 to April 2004.

Mickey A. Brown
Executive Vice President
Age 61
Elected in 2001. Executive Vice President of the Customer Service Organization since January 2005. Previously served as Senior Vice President of Distribution from May 2001 through December 2004.

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer, and Treasurer
Age 58
Elected in 2005. Executive Vice President, Chief Financial Officer, and Treasurer since March 2005. Previously served as Senior Vice President, Comptroller, and Chief Financial Officer of Southern Power from November 2002 to March 2005 and Vice President of SCS from June 2002 to March 2005.

Judy M. Anderson
Senior Vice President
Age 60
Elected in 2001. Senior Vice President of Charitable Giving since 2001.

W. Craig Barrs
Senior Vice President
Age 51
Elected in 2008. Senior Vice President of External Affairs since January 2009. Previously served as Vice President of Governmental and Regulatory Affairs from April 2008 to December 2008, Vice President of the Coastal Region from August 2006 to March 2008, President and Chief Executive Officer of Savannah Electric and Power Company from January 2006 until its merger with and into Georgia Power which was completed in July 2006, and Vice President of Community and Economic Development from November 2002 to December 2005.

Douglas E. Jones
Senior Vice President
Age 50
Elected in 2005. Senior Vice President of Fossil and Hydro Generation since March 2006. Previously served as Senior Vice President of Customer Service and Sales from January 2005 to February 2006 and Executive Vice President of Southern Power from January 2004 to January 2005.

Thomas P. Bishop
Senior Vice President, Chief Compliance Officer, and General Counsel
Age 48
Elected in 2008. Senior Vice President, Chief Compliance Officer, and General Counsel since September 2008. Previously served as Vice President and Associate General Counsel for SCS from July 2004 to September 2008 and Managing Attorney for SCS from April 1997 to July 2004.

Each of the above is currently an executive officer of Georgia Power, serving a term running from the last annual organizational meeting of the directors (May 21, 2008) for one year until the next annual meeting or until their successors are elected and qualified, except for Mr. Bishop and Mr. Barrs whose elections were effective September 22, 2008 and January 1, 2009, respectively.

EXECUTIVE OFFICERS OF MISSISSIPPI POWER

(Identification of executive officers of Mississippi Power is inserted in Part I in accordance with Regulation S-K, Item 401(b), Instruction 3.) The ages of the officers set forth below are as of December 31, 2008.

Anthony J. Topazi
President, Chief Executive Officer, and Director
Age 58
Elected in 2003. President, Chief Executive Officer, and Director since January 1, 2004.

John W. Atherton
Vice President
Age 48
Elected in 2004. Vice President of External Affairs since January 2005. Previously served as the Director of Economic Development from September 2003 to January 2005.

Kimberly D. Flowers
Vice President
Age 45
Elected in 2005. Vice President and Senior Production Officer since March 2005. Previously served as Plant Manager, Plant Bowen, Georgia Power from November 2000 until March 2005.

Donald R. Horsley
Vice President
Age 54
Elected in 2006. Vice President of Customer Services and Retail Marketing since April 2006. Previously served as Vice President of Transmission at Alabama Power from March 2005 to March 2006 and Manager, Transmission Lines at Alabama Power from February 2001 to March 2005.

Frances Turnage
Vice President, Treasurer, and
Chief Financial Officer
Age 60
Elected in 2005. Vice President, Treasurer, and Chief Financial Officer since March 2005. Previously served as Comptroller from 1993 to March 2005.

The officers of Mississippi Power were elected for a term running from the last annual organizational meeting of the directors (April 9, 2008) for one year until the next annual meeting or until their successors are elected and have qualified.

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PART II

Item 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(a)(1) The common stock of Southern Company is listed and traded on the New York Stock Exchange. The common stock is also traded on regional exchanges across the United States. The high and low stock prices as reported on the New York Stock Exchange for each quarter of the past two years were as follows:

	High	Low
2008		
First Quarter	$ 40.60	$33.71
Second Quarter	37.81	34.28
Third Quarter	40.00	34.46
Fourth Quarter	38.18	29.82
2007		
First Quarter	$ 37.25	$ 34.85
Second Quarter	38.90	33.50
Third Quarter	37.70	33.16
Fourth Quarter	39.35	35.15

There is no market for the other registrants' common stock, all of which is owned by Southern Company.

(a)(2) Number of Southern Company's common stockholders of record at December 31, 2008: 97,324

Each of the other registrants have one common stockholder, Southern Company.

(a)(3) Dividends on each registrant's common stock are payable at the discretion of their respective board of directors. The dividends on common stock declared by Southern Company and the traditional operating companies to their stockholder(s) for the past two years were as follows:

Registrant	Quarter	2008	2007
		(in thousands)	
Southern Company	First	$ 307,960	$ 290,292
	Second	322,634	303,699
	Third	323,844	304,775
	Fourth	325,681	306,039
Alabama Power	First	122,825	116,250
	Second	122,825	116,250
	Third	122,825	116,250
	Fourth	122,825	116,250
Georgia Power	First	180,300	172,475
	Second	180,300	172,475
	Third	180,300	172,475
	Fourth	180,300	172,475
Gulf Power	First	20,425	18,525
	Second	20,425	18,525
	Third	20,425	18,525
	Fourth	20,425	18,525
Mississippi Power	First	17,100	16,825
	Second	17,100	16,825
	Third	17,100	16,825
	Fourth	17,100	16,825

In 2007 and 2008, Southern Power paid dividends to Southern Company as follows:

Registrant	Quarter	2008	2007
		(in millions)	
Southern Power	First	$23.63	$22.45
	Second	23.63	22.45
	Third	23.63	22.45
	Fourth	23.63	22.45

The dividend paid per share of Southern Company's common stock was 38.75¢ for the first quarter of 2007 and 40.25¢ for the remaining quarters in 2007 and the first quarter of 2008. For the second, third, and fourth quarters of 2008, the dividend paid per share of Southern Company's common stock was 42¢.

The traditional operating companies and Southern Power can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Southern Power's credit facility and senior note indenture contain potential limitations on the payment of common stock dividends. At December 31, 2008, Southern Power was in compliance with the conditions of this credit facility and thus had no restrictions on its ability to pay common stock dividends. See Note 8 to the financial statements of Southern Company under "Common Stock Dividend Restrictions" and Note 6 to the financial statements of Southern Power under "Dividend Restrictions" in Item 8 herein for additional information regarding these restrictions.

(a)(4) Securities authorized for issuance under equity compensation plans.

See Part III, Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters under the heading "Equity Compensation Plan Information" herein.

(b) Use of Proceeds

Not applicable.

(c) Issuer Purchases of Equity Securities

None.

Item 6. SELECTED FINANCIAL DATA

Southern Company. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA," contained herein at pages II-106 and II-107.

Alabama Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-170 and II-171.

Georgia Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-239 and II-240.

Gulf Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-298 and II-299.

Mississippi Power. See "SELECTED FINANCIAL AND OPERATING DATA," contained herein at pages II-363 and II-364.

Southern Power. See "SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA," contained herein at page II-406.

Item 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Southern Company. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-12 through II-49.

Alabama Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-111 through II-132.

Georgia Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-175 through II-198.

Gulf Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-244 through II-265.

Mississippi Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-303 through II-327.

Southern Power. See "MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS," contained herein at pages II-368 through II-386.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See MANAGEMENT'S DISCUSSION AND ANALYSIS - FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" of each of the registrants in Item 7 herein and Note 1 of each of the registrant's financial statements under "Financial Instruments" in Item 8 herein. See also Note 6 to the financial statements of Southern Company, each traditional operating company, and Southern Power under "Financial Instruments" in Item 8 herein.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Item 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

Item 9A. CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this annual report, Southern Company conducted an evaluation under the supervision and with the participation of Southern Company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

Southern Company's Management's Report on Internal Control Over Financial Reporting is included on page II-9 of this Form 10-K.

(b) Attestation Report of the Registered Public Accounting Firm.

The report of Deloitte & Touche LLP, Southern Company's independent registered public accounting firm, regarding Southern Company's internal control over financial reporting is included on pages II-10 and II-11 of this Form 10-K.

(c) Changes in internal controls.

There have been no changes in Southern Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2008 that have materially affected or are reasonably likely to materially affect Southern Company's internal control over financial reporting.

Item 9A(T). CONTROLS AND PROCEDURES

Disclosure Controls And Procedures.

As of the end of the period covered by this annual report, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power conducted separate evaluations under the supervision and with the participation of each company's management, including the Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the disclosure controls and procedures (as defined in Sections 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934). Based upon these evaluations, the Chief Executive Officer and the Chief Financial Officer, in each case, concluded that the disclosure controls and procedures are effective.

Internal Control Over Financial Reporting.

(a) Management's Annual Report on Internal Control Over Financial Reporting.

Alabama Power's Management's Report on Internal Control Over Financial Reporting is included on page II-109 of this Form 10-K.

Georgia Power's Management's Report on Internal Control Over Financial Reporting is included on page II-173 of this Form 10-K.

Gulf Power's Management's Report on Internal Control Over Financial Reporting is included on page II-242 of this Form 10-K.

Mississippi Power's Management's Report on Internal Control Over Financial Reporting is included on page II-301 of this Form 10-K.

Southern Power's Management's Report on Internal Control Over Financial Reporting is included on page II-366 of this Form 10-K.

(b) Changes in internal controls.

There have been no changes in Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934) during the fourth quarter 2008 that have materially affected or are reasonably likely to materially affect Alabama Power's, Georgia Power's, Gulf Power's, Mississippi Power's, or Southern Power's internal control over financial reporting.

Item 9B. OTHER INFORMATION

None.

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THE SOUTHERN COMPANY
AND SUBSIDIARY COMPANIES

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

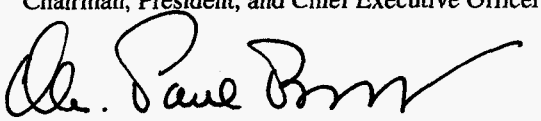
Southern Company and Subsidiary Companies 2008 Annual Report

Southern Company's management is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of Southern Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that Southern Company's internal control over financial reporting was effective as of December 31, 2008.

Deloitte & Touche LLP, an independent registered public accounting firm, as auditors of Southern Company's financial statements, has issued an attestation report on the effectiveness of Southern Company's internal control over financial reporting as of December 31, 2008. Deloitte & Touche LLP's report on Southern Company's internal control over financial reporting is included herein.

David M. Ratcliffe
Chairman, President, and Chief Executive Officer



W. Paul Bowers
Executive Vice President and Chief Financial Officer

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of Southern Company and Subsidiary Companies (the "Company") as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2008. We also have audited the Company's internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting (page II-9). Our responsibility is to express an opinion on these financial statements and an opinion on the Company's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM (continued)

In our opinion, the consolidated financial statements (pages II-50 to II-104) referred to above present fairly, in all material respects, the financial position of Southern Company and Subsidiary Companies as of December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

OVERVIEW

Business Activities

The primary business of Southern Company (the Company) is electricity sales in the Southeast by the traditional operating companies – Alabama Power, Georgia Power, Gulf Power, and Mississippi Power – and Southern Power. The four traditional operating companies are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market.

Many factors affect the opportunities, challenges, and risks of Southern Company's electricity business. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment, to maintain energy sales in the midst of the current economic downturn, and to effectively manage and secure timely recovery of rising costs. Each of the traditional operating companies has various regulatory mechanisms that operate to address cost recovery. Since 2005, the traditional operating companies have completed a number of regulatory proceedings that provide for the timely recovery of costs. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future.

Another major factor is the profitability of the competitive market-based wholesale generating business and federal regulatory policy, which may impact Southern Company's level of participation in this market. Southern Power continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into power purchase agreements (PPAs) with investor owned utilities, independent power producers, municipalities, and electric cooperatives. The Company continues to face regulatory challenges related to transmission and market power issues at the national level.

Southern Company's other business activities include leveraged lease projects, telecommunications, and energy-related services. Management continues to evaluate the contribution of each of these remaining activities to total shareholder return and may pursue acquisitions and dispositions accordingly.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than four million customers, Southern Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and earnings per share (EPS), excluding charges related to leveraged leases. Southern Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2008 Peak Season EFOR of 1.68% was better than the target. The nuclear generating fleet also uses Peak Season EFOR as an indicator of availability and efficient generation fleet operations during the peak season. The nuclear 2008 Peak Season EFOR of 1.98% was slightly better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2008 was better than the target for these reliability measures.

Southern Company's investments include three leveraged lease transactions whose tax deductions have been challenged by the Internal Revenue Service (IRS). Ongoing settlement negotiations with the IRS resulted in a charge to income of $83 million, or 11 cents per share, in 2008. Southern Company management uses EPS, excluding leveraged lease charges, to evaluate the performance of Southern Company's ongoing business activities. Southern Company believes the presentation of earnings and EPS excluding the leveraged lease charges is useful for investors because it provides investors with additional information for purposes of comparing Southern Company's performance for such periods. The presentation of this additional information is not meant to be considered a substitute for financial measures prepared in accordance with generally accepted accounting principles.

Southern Company's 2008 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2008 Target Performance	2008 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR - fossil/hydro	2.75% or less	1.68%
Peak Season EFOR - nuclear	2.00% or less	1.98%
Basic EPS	$2.28 – $2.36	$2.26
EPS, excluding leveraged lease charges	–	$2.37

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2008 reflects the continued emphasis that management places on these indicators as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

Southern Company's net income was $1.74 billion in 2008, an increase of $8 million from the prior year. Compared with the prior year, increases in retail rates and increases in revenues from market-response rates to large commercial and industrial customers were mostly offset by higher asset depreciation, milder summer temperatures compared to 2007, higher non-fuel operations and maintenance expenses, charges related to the leveraged lease business, and exiting the synthetic fuel business in 2007. Net income was $1.73 billion in 2007 and $1.57 billion in 2006, reflecting a 10.2% increase and a 1.1% decrease, respectively, over the prior year. Basic EPS was $2.26 in 2008, $2.29 in 2007, and $2.12 in 2006. Diluted EPS, which factors in additional shares related to stock-based compensation, was $2.25 in 2008, $2.28 in 2007, and $2.10 in 2006.

Dividends

Southern Company has paid dividends on its common stock since 1948. Dividends paid per share of common stock were $1.6625 in 2008, $1.595 in 2007, and $1.535 in 2006. In January 2009, Southern Company declared a quarterly dividend of 42 cents per share. This is the 245th consecutive quarter that Southern Company has paid a dividend equal to or higher than the previous quarter. The Company targets a dividend payout ratio of approximately 65% to 70% of net income. For 2008, the actual payout ratio was 73.5% while the payout ratio of net income excluding leveraged lease charges was 70.1%.

RESULTS OF OPERATIONS

Electricity Business

Southern Company's electric utilities generate and sell electricity to retail and wholesale customers in the Southeast. A condensed statement of income for the electricity business follows:

	Amount	Increase (Decrease) from Prior Year		
	2008	2008	2007	2006
		(in millions)		
Electric operating revenues	$ 17,000	$ 1,860	$ 1,052	$ 810
Fuel	6,817	973	701	655
Purchased power	815	300	(28)	(188)
Other operations and maintenance	3,584	111	183	70
Depreciation and amortization	1,414	199	51	27
Taxes other than income taxes	794	56	23	39
Total electric operating expenses	13,424	1,639	930	603
Operating income	3,576	221	122	207
Other income (expense), net	145	24	68	(9)
Interest expense and dividends	837	25	61	75
Income taxes	1,037	87	1	50
Net income	$ 1,847	$ 133	$ 128	$ 73

Electric Operating Revenues

Details of electric operating revenues were as follows:

	Amount		
	2008	2007	2006
		(in millions)	
Retail – prior year	$ 12,639	$ 11,801	$ 11,165
Estimated change in –			
Rates and pricing	668	161	9
Sales growth	-	60	115
Weather	(106)	54	35
Fuel and other cost recovery	854	563	477
Retail – current year	14,055	12,639	11,801
Wholesale revenues	2,400	1,988	1,822
Other electric operating revenues	545	513	465
Electric operating revenues	$ 17,000	$ 15,140	$ 14,088
Percent change	12.3%	7.5%	6.1%

Retail revenues increased $1.4 billion, $838 million, and $636 million in 2008, 2007, and 2006, respectively. The significant factors driving these changes are shown in the preceding table. The increase in rates and pricing in 2008 was primarily due to Alabama Power's increase under its Rate Stabilization and Equalization Plan (Rate RSE), as ordered by the Alabama Public Service Commission (PSC), and Georgia Power's increase under its 2007 retail rate

plan, as ordered by the Georgia PSC. See Note 3 to the financial statements under "Alabama Power Retail Regulatory Matters" and "Georgia Power Retail Regulatory Matters" for additional information. Also contributing to the 2008 increase was an increase in revenues from market-response rates to large commercial and industrial customers at Georgia Power. The 2007 increase in rates and pricing when compared to the prior year was primarily due to Alabama Power's increase under its Rate RSE, as ordered by the Alabama PSC. Partially offsetting the 2007 increase was a decrease in revenues from market-response rates to large commercial and industrial customers at Georgia Power. The 2006 increase in rates and pricing when compared to the prior year was not material. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. The traditional operating companies may also have one or more regulatory mechanisms to recover other costs such as environmental, storm damage, new plants, and PPAs.

Wholesale revenues consist of PPAs with investor-owned utilities and electric cooperatives, unit power sales contracts, and short-term opportunity sales. Short-term opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy. Southern Company's average wholesale contract extends more than 14 years and, as a result, the Company has significantly limited its remarketing risk.

In 2008, wholesale revenues increased $412 million primarily as a result of a 21.8% increase in the average cost of fuel per net kilowatt-hour (KWH) generated, as well as revenues resulting from new and existing PPAs and revenues derived from contracts for Southern Power's Plant Oleander Unit 5 and Plant Franklin Unit 3 placed in operation in December 2007 and June 2008, respectively. The 2008 increase was partially offset by a decrease in short-term opportunity sales and weather-related generation load reductions.

In 2007, wholesale revenues increased $166 million primarily as a result of a 9.9% increase in the average cost of fuel per net KWH generated. Excluding fuel, wholesale revenues were flat when compared to the prior year.

In 2006, wholesale revenues increased $155 million primarily as a result of a 10.0% increase in the average cost of fuel per net KWH generated, as well as revenues resulting from new PPAs in 2006. In addition, Southern Company assumed four PPAs through the acquisitions of Plants DeSoto and Rowan in June and September 2006, respectively. The 2006 increase was partially offset by a decrease in short-term opportunity sales.

Revenues associated with PPAs and opportunity sales were as follows:

	2008	2007	2006
		(in millions)	
Other power sales –			
Capacity and other	**$ 538**	$ 533	$ 499
Energy	**1,319**	989	841
Total	**$ 1,857**	$ 1,522	$ 1,340

Capacity revenues under unit power sales contracts, principally sales to Florida utilities, reflect the recovery of fixed costs and a return on investment. Unit power KWH sales decreased 2.1% in 2008, decreased 0.8% in 2007, and increased 0.2% in 2006. Fluctuations in oil and natural gas prices, which are the primary fuel sources for unit power sales customers, influence changes in these sales. However, because the energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings. The capacity and energy components of the unit power sales contracts were as follows:

	2008	2007	2006
		(in millions)	
Unit power sales –			
Capacity	**$ 223**	$ 202	$ 208
Energy	**320**	264	274
Total	**$ 543**	$ 466	$ 482

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2008 and the percent change by year were as follows:

	KWHs	Percent Change		
	2008	**2008**	2007	2006
	(in billions)			
Residential	**52.3**	**(2.0)%**	1.8%	2.5%
Commercial	**54.4**	**(0.4)**	3.2	2.2
Industrial	**52.7**	**(3.7)**	(0.7)	(0.2)
Other	**0.9**	**(2.9)**	4.4	(7.6)
Total retail	**160.3**	**(2.1)**	1.4	1.4
Wholesale	**39.3**	**(3.4)**	5.9	3.7
Total energy sales	**199.6**	**(2.3)**	2.3	1.9

KWH sales by quarter for 2008 compared to the same periods in 2007 were as follows:

	KWHs			Percent Change		
Quarter Ended	**Retail**	**Wholesale**	**Total Energy Sales**	**Retail**	**Wholesale**	**Total Energy Sales**
		(in millions)				
March 2008	**38,576**	**9,590**	**48,166**	**1.4%**	**(1.9)%**	**0.7%**
June 2008	**39,882**	**10,049**	**49,931**	**(1.2)**	**1.0**	**(0.7)**
September 2008	**45,800**	**10,969**	**56,769**	**(4.6)**	**(2.2)**	**(4.1)**
December 2008	**36,001**	**8,760**	**44,761**	**(3.3)**	**(10.6)**	**(4.8)**

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2008 decreased 3.4 billion KWHs as a result of a 1.4% decrease in electricity usage mainly due to a slowing economy that worsened during the fourth quarter. The 2008 decrease in residential sales resulted primarily from lower home occupancy rates in Southern Company's service area when compared to 2007. Throughout the year, reduced demand in the textile sector; the lumber sector; and the stone, clay, and glass sector contributed to the decrease in 2008 industrial sales. Additional weakness in the fourth quarter 2008 affected all major industrial segments. Significantly less favorable weather in 2008 when compared to

2007 also contributed to the 2008 decrease in retail energy sales. These decreases were partially offset by customer growth of 0.6%. Retail energy sales in 2007 increased 2.3 billion KWHs as a result of 1.3% customer growth and favorable weather in 2007 when compared to 2006. The 2007 decrease in industrial sales primarily resulted from reduced demand and closures within the textile sector, as well as decreased demand in the primary metals sector and the stone, clay, and glass sector. Retail energy sales in 2006 increased 2.3 billion KWHs as a result of customer growth of 1.7%, sustained economic growth primarily in the residential and commercial customer classes, and favorable weather in 2006 when compared to 2005.

Wholesale energy sales decreased by 1.4 billion KWHs in 2008, increased by 2.3 billion KWHs in 2007, and increased by 1.4 billion KWHs in 2006. The decrease in wholesale energy sales in 2008 was primarily related to longer planned maintenance outages at a fossil unit in 2008 as compared to 2007 which reduced the availability of this unit for wholesale sales. Lower short-term opportunity sales primarily related to higher coal prices also contributed to the 2008 decrease. These decreases were partially offset by Plant Oleander Unit 5 and Plant Franklin Unit 3 being placed in operation in December 2007 and June 2008, respectively. The increase in wholesale energy sales in 2007 was primarily related to new PPAs acquired by Southern Company through the acquisition of Plant Rowan in September 2006, as well as new contracts with EnergyUnited Electric Membership Corporation that commenced in September 2006 and January 2007. An increase in KWH sales under existing PPAs also contributed to the 2007 increase. The increase in wholesale energy sales in 2006 was related primarily to the new PPAs discussed previously under "Electric Operating Revenues."

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the electric utilities. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the electric utilities purchase a portion of their electricity needs from the wholesale market. Details of Southern Company's electricity generated and purchased were as follows:

	2008	2007	2006
Total generation *(billions of KWHs)*	**198**	206	201
Total purchased power *(billions of KWHs)*	**11**	8	8
Sources of generation *(percent)* –			
Coal	**68**	70	70
Nuclear	**15**	14	15
Gas	**16**	15	13
Hydro	**1**	1	2
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.27**	2.60	2.40
Nuclear	**0.50**	0.50	0.47
Gas	**7.58**	6.64	6.63
Average cost of fuel, generated *(cents per net KWH)*	**3.52**	2.89	2.63
Average cost of purchased power *(cents per net KWH)*	**7.85**	7.20	6.82

In 2008, fuel and purchased power expenses were $7.6 billion, an increase of $1.3 billion or 20.0% above 2007 costs. This increase was primarily the result of a $1.3 billion net increase in the average cost of fuel and purchased power partially resulting from a 25.8% increase in the cost of coal per net KWH generated and a 14.2% increase in the cost of gas per net KWH generated.

In 2007, fuel and purchased power expenses were $6.4 billion, an increase of $673 million or 11.8% above 2006 costs. This increase was primarily the result of a $543 million net increase in the average cost of fuel and purchased power partially resulting from a 51.4% decrease in hydro generation as a result of a severe drought. Also contributing to this increase was a $130 million increase related to higher net KWHs generated and purchased.

In 2006, fuel and purchased power expenses were $5.7 billion, an increase of $467 million or 8.9% above the prior year costs. This increase was primarily the result of a $367 million net increase in the average cost of fuel and purchased power and a $100 million increase related to higher net KWHs generated and purchased.

Over the last several years, coal prices have been influenced by a worldwide increase in demand from developing countries, as well as increases in mining and fuel transportation costs. In the first half of 2008, coal prices reached unprecedented high levels primarily due to increased demand following more moderate pricing in 2006 and 2007. Despite these fluctuations, fuel inventories have been adequate and fuel supply markets have been sufficient to meet expected fuel requirements. Demand for natural gas in the United States also increased in 2007 and the first half of 2008. However, natural gas supplies increased in the last half of 2008 as a result of increased production and higher storage levels due in part to weak industrial demand. Both coal and natural gas prices moderated in the second half of 2008 as the result of a recessionary economy. During 2008, uranium prices continued to moderate from the highs set during 2007. While worldwide uranium production levels appear to have increased slightly since 2007, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the traditional operating companies' fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information. Likewise, Southern Power's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses were $3.6 billion, $3.5 billion, and $3.3 billion, increasing $111 million, $183 million, and $70 million in 2008, 2007, and 2006, respectively. Discussion of significant variances for components of other operations and maintenance expenses follows.

Other production expenses at fossil, hydro, and nuclear plants increased $63 million, $128 million, and $3 million in 2008, 2007, and 2006, respectively. Production expenses fluctuate from year to year due to variations in outage schedules and normal increases in costs. Other production expenses increased in 2008 primarily due to a $64 million increase related to expenses incurred for maintenance outages at generating units and a $30 million increase related to labor and materials expenses, partially offset by a $15 million decrease in nuclear refueling costs. See Note 1 to the financial statements under "Property, Plant, and Equipment" for additional information regarding nuclear refueling costs. The 2008 increase was also partially offset by a $24 million decrease related to new facilities, mainly lower costs associated with the 2007 write-off of Southern Power's integrated coal gasification combined cycle (IGCC) project with the Orlando Utilities Commission. Other production expenses increased in 2007 primarily due to a $40 million increase related to expenses incurred for maintenance outages at generating units and a $29 million increase related to new facilities, mainly costs associated with the write-off of Southern Power's IGCC project and the acquisitions of Plants DeSoto and Rowan by Southern Power in June and September 2006, respectively. A $25 million increase related to labor and materials expenses and a $22 million increase in nuclear refueling costs also contributed to the 2007 increase. The 2006 increase in other production expenses when compared to the prior year was not material.

Transmission and distribution expenses increased $4 million, $21 million, and $30 million in 2008, 2007, and 2006, respectively. Transmission and distribution expenses fluctuate from year to year due to variations in maintenance schedules and normal increases in costs. The 2008 increase in transmission and distribution expenses was not material when compared to the prior year. Transmission and distribution expenses increased in 2007 primarily as a result of increases in labor and materials costs and maintenance associated with additional investment to meet customer growth. Transmission and distribution expenses increased in 2006 primarily due to expenses associated

with recovery of prior year storm costs through natural disaster recovery clauses in accordance with an accounting order approved by the Alabama PSC and maintenance associated with additional investment in distribution to meet customer growth.

Customer sales and service expenses increased $32 million, $7 million, and $9 million in 2008, 2007, and 2006, respectively. Customer sales and service expenses increased in 2008 primarily as a result of an increase in customer account expenses, including a $13 million increase in uncollectible accounts expense, a $9 million increase in meter reading and related supervision expenses, and an $8 million increase for records and collections. The 2007 and 2006 increases in customer sales and service expenses were not material when compared to the prior years.

Administrative and general expenses increased $10 million, $28 million, and $29 million in 2008, 2007, and 2006, respectively. The 2008 increase in administrative and general expenses was not material when compared to the prior year. Administrative and general expenses increased in 2007 primarily as a result of a $16 million increase in legal costs and expenses associated with an increase in employees. Also contributing to the 2007 increase was a $14 million increase in accrued expenses for the litigation and workers' compensation reserve, partially offset by an $8 million decrease in property damage expense. Administrative and general expenses increased in 2006 primarily as a result of a $17 million increase in salaries and wages and a $24 million increase in pension expense, partially offset by a $16 million reduction in medical expenses.

Depreciation and Amortization

Depreciation and amortization increased $199 million in 2008 primarily as a result of an increase in plant in service related to environmental, transmission, and distribution projects mainly at Alabama Power and Georgia Power and generation projects at Georgia Power. An increase in depreciation rates at Georgia Power and Southern Power also contributed to the 2008 increase, as well as the expiration of a rate order previously allowing Georgia Power to levelize certain purchased power capacity costs and the completion of Plant Oleander Unit 5 in December 2007 and Plant Franklin Unit 3 in June 2008.

Depreciation and amortization increased $51 million in 2007 primarily as a result of an increase in plant in service related to environmental, transmission, and distribution projects mainly at Alabama Power and Georgia Power. An increase in the amortization expense of a regulatory liability recorded in 2003 in connection with the Mississippi PSC's accounting order on Plant Daniel capacity also contributed to the 2007 increase. Partially offsetting the 2007 increase was a reduction in amortization expense due to a Georgia Power regulatory liability related to the levelization of certain purchased power capacity costs as ordered by the Georgia PSC under the terms of the retail rate order effective January 1, 2005. See Note 1 to the financial statements under "Depreciation and Amortization" for additional information.

Depreciation and amortization increased $27 million in 2006 primarily as a result of the acquisitions of Plants DeSoto, Rowan, and Oleander in June 2006, September 2006, and June 2005, respectively, and an increase in the amortization expense of the Mississippi Power regulatory liability related to Plant Daniel capacity. An increase in depreciation rates at Southern Power also contributed to the 2006 increase. Partially offsetting the 2006 increase was a reduction in the amortization expense of a Georgia Power regulatory liability related to the levelization of certain purchased power capacity costs.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $56 million in 2008 primarily as a result of increases in franchise fees and municipal gross receipt taxes associated with increases in revenues from energy sales, as well as increases in property taxes associated with property tax actualizations and additional plant in service. Taxes other than income taxes increased $23 million in 2007 primarily as a result of increases in franchise and municipal gross receipts taxes

associated with increases in revenues from energy sales, partially offset by a decrease in property taxes resulting from the resolution of a dispute with Monroe County, Georgia. Taxes other than income taxes increased $39 million in 2006 primarily as a result of increases in franchise and municipal gross receipts taxes associated with increases in revenues from energy sales, as well as increases in property taxes associated with additional plant in service.

Other Income (Expense), Net

Other income (expense), net increased $24 million in 2008 primarily as a result of an increase in allowance for equity funds used during construction related to additional investments in environmental equipment at generating plants at Alabama Power, Georgia Power, and Gulf Power, as well as additional investments in transmission and distribution projects mainly at Alabama Power and Georgia Power. Other income (expense), net increased $68 million in 2007 primarily as a result of an increase in allowance for equity funds used during construction related to additional investments in environmental equipment at generating plants and transmission and distribution projects mainly at Alabama Power and Georgia Power. The 2006 decrease in other income (expense), net when compared to the prior year was not material.

Interest Expense and Dividends

Total interest charges and other financing costs increased by $25 million in 2008 primarily as a result of an $82 million increase associated with $1.7 billion in additional debt and preference stock outstanding at December 31, 2008 compared to December 31, 2007. Also contributing to the 2008 increase was $5 million in other interest costs. The 2008 increase was partially offset by $55 million related to lower average interest rates on existing variable rate debt and $7 million of additional capitalized interest as compared to 2007.

Total interest charges and other financing costs increased by $61 million in 2007 primarily as a result of a $72 million increase associated with $1.2 billion in additional debt and preference stock outstanding at December 31, 2007 compared to December 31, 2006 and higher interest rates associated with the issuance of new long-term debt. Also contributing to the 2007 increase was $7 million related to higher average interest rates on existing variable rate debt and $19 million in other interest costs. The 2007 increase was partially offset by $38 million of additional capitalized interest as compared to 2006.

Total interest charges and other financing costs increased by $75 million in 2006 primarily due to a $78 million increase associated with $708 million in additional debt outstanding at December 31, 2006 compared to December 31, 2005 and higher interest rates associated with the issuance of new long-term debt. Also contributing to the 2006 increase was $7 million associated with higher average interest rates on existing variable rate debt, partially offset by $6 million of additional capitalized interest associated with construction projects and $3 million in lower other interest costs.

Income Taxes

Income taxes increased $87 million in 2008 primarily due to higher pre-tax earnings as compared to 2007 and a 2007 deduction for a Georgia Power land donation. The 2008 increase was partially offset by an increase in allowance for equity funds used during construction, which is not taxable. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Income taxes were relatively flat in 2007 as higher pre-tax earnings as compared to 2006 were largely offset due to a deduction for a Georgia Power land donation; an increase in allowance for equity funds used during construction, which is not taxable; and an increase in the Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 199 production activities deduction.

Income taxes increased $50 million in 2006 primarily due to higher pre-tax earnings as compared to 2005 and the impact of a 2005 accounting order approved by the Alabama PSC to return certain regulatory liabilities related to deferred taxes to Alabama Power's retail customers.

Other Business Activities

Southern Company's other business activities include the parent company (which does not allocate operating expenses to business units), investments in leveraged lease and synthetic fuel projects, telecommunications, and energy-related services. These businesses are classified in general categories and may comprise one or more of the following subsidiaries: Southern Company Holdings invests in various energy-related projects, including leveraged lease and synthetic fuel projects that receive tax benefits, which have contributed significantly to the economic results of these investments; SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast.

Southern Company's investment in synthetic fuel projects ended at December 31, 2007. A condensed statement of income for Southern Company's other business activities follows:

	Amount	Increase (Decrease) from Prior Year		
	2008	2008	2007	2006
		(in millions)		
Operating revenues	$ 127	$ (86)	$ (55)	$ (8)
Other operations and maintenance	165	(44)	(29)	(59)
Depreciation and amortization	29	(1)	(6)	(3)
Taxes other than income taxes	3	-	-	(1)
Total operating expenses	197	(45)	(35)	(63)
Operating income (loss)	(70)	(41)	(20)	55
Equity in income (losses) of unconsolidated subsidiaries	10	35	35	62
Leveraged lease income (losses)	(85)	(125)	(29)	(5)
Other income (expense), net	12	(29)	73	(19)
Interest expense	94	(28)	(27)	48
Income taxes	(122)	(7)	53	136
Net income (loss)	$ (105)	$ (125)	$ 33	$ (91)

Operating Revenues

Southern Company's non-electric operating revenues from these other businesses decreased $86 million in 2008 primarily as a result of a $60 million decrease associated with Southern Company terminating its investment in synthetic fuel projects at December 31, 2007 and a $21 million decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and fewer subscribers due to increased competition in the industry. Also contributing to the 2008 decrease was a $5 million decrease in revenues from Southern Company's energy-related services business. The $55 million decrease in 2007 primarily resulted from a $14 million decrease in fuel procurement service revenues following a contract termination, a $13 million decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and fewer subscribers due to increased competition in the industry, and an $11 million decrease in revenues from Southern Company's energy-related services business. The $8 million decrease in 2006 primarily resulted from a $21 million decrease in revenues at SouthernLINC Wireless related to lower average revenue per subscriber and lower equipment and accessory sales. The 2006 decrease was partially offset by a $12 million increase in fuel procurement service revenues.

Other Operations and Maintenance Expenses

Other operations and maintenance expenses for these other businesses decreased $44 million in 2008 primarily as a result of $11 million of lower coal expenses related to Southern Company terminating its investment in synthetic fuel projects at December 31, 2007; $9 million of lower sales expenses at SouthernLINC Wireless related to lower sales volume; and $5 million of lower parent company expenses related to advertising, litigation, and property insurance costs. Other operations and maintenance expenses decreased $29 million in 2007 primarily as a result of $11 million of lower production expenses related to the termination of Southern Company's membership interest in one of the synthetic fuel entities and $8 million attributed to the wind-down of one of the Company's energy-related services businesses. Other operations and maintenance expenses decreased $59 million in 2006 primarily as a result of $32 million of lower production expenses related to the termination of Southern Company's membership interest in one of the synthetic fuel entities, $13 million attributed to the wind-down of one of the Company's energy-related services businesses, and $7 million of lower expenses resulting from the March 2006 sale of a subsidiary that provided rail car maintenance services.

Equity in Income (Losses) of Unconsolidated Subsidiaries

Southern Company made investments in two synthetic fuel production facilities that generated operating losses. These investments allowed Southern Company to claim federal income tax credits that offset these operating losses and made the projects profitable. Equity in income of unconsolidated subsidiaries increased $35 million in 2008 as a result of Southern Company terminating its investment in synthetic fuel projects at December 31, 2007. Equity in losses of unconsolidated subsidiaries decreased $35 million in 2007 as a result of terminating Southern Company's membership interest in one of the synthetic fuel entities which reduced the amount of the Company's share of the losses and, therefore, the funding obligation for the year. Also contributing to the 2007 decrease were adjustments to the phase-out of the related federal income tax credits, partially offset by higher operating expenses due to idled production in 2006 and decreased production in 2007 in anticipation of exiting the business. Equity in losses of unconsolidated subsidiaries decreased $62 million in 2006 as a result of terminating Southern Company's membership interest in one of the synthetic fuel entities which reduced the amount of the Company's share of the losses and, therefore, the funding obligation for the year. The 2006 decrease also resulted from lower operating expenses while the production facilities at the other synthetic fuel entity were idled from May to September 2006 due to higher oil prices.

Leveraged Lease Income (Losses)

Southern Company has several leveraged lease agreements which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. Leveraged lease losses increased $125 million in 2008 as a result of Southern Company's decision to participate in a settlement with the IRS related to deductions for several sale-in-lease-out (SILO) transactions and the resulting application of Financial Accounting Standards Board (FASB) Staff Position No. FAS 13-2, "Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction" (FSP 13-2). See Note 3 to the financial statements under "Income Tax Matters – Leveraged Leases" for further information. Leveraged lease income decreased $29 million in 2007 as a result of the adoption of FSP 13-2, as well as an expected decline in leveraged lease income over the terms of the leases. The 2006 decrease in leveraged lease income when compared to the prior year was not material.

Other Income (Expense), Net

Other income (expense), net for these other businesses decreased $29 million in 2008 primarily as a result of the 2007 gain on a derivative transaction in the synthetic fuel business which settled on December 31, 2007. Other income (expense), net increased $73 million in 2007 primarily as a result of a $60 million increase related to changes in the value of derivative transactions in the synthetic fuel business and a $16 million increase related to the 2006 impairment of investments in the synthetic fuel entities, partially offset by the release of $6 million in certain contractual obligations associated with these investments in 2006. Other income (expense), net decreased $19 million in 2006 primarily as a result of a $25 million decrease related to changes in the value of derivative transactions in the synthetic fuel business and the previously mentioned impairment and release of contractual obligations.

Interest Expense

Total interest charges and other financing costs for these other businesses decreased $28 million in 2008 primarily as a result of $29 million associated with lower average interest rates on existing variable rate debt and a $4 million decrease attributed to lower interest rates associated with new debt issued to replace maturing securities. At December 31, 2008, these other businesses had $92 million in additional debt outstanding compared to December 31, 2007. The 2008 decrease was partially offset by a $5 million increase in other interest costs. Total interest charges and other financing costs decreased by $27 million in 2007 primarily as a result of $16 million of losses on debt that was reacquired in 2006. Also contributing to the 2007 decrease was $97 million less debt outstanding at December 31, 2007 compared to December 31, 2006, lower interest rates associated with the issuance of new long-term debt, and a $4 million decrease in other interest costs. Total interest charges and other financing costs increased by $48 million in 2006 primarily as a result of a $19 million increase associated with $149 million in additional debt outstanding at December 31, 2006 as compared to December 31, 2005 and higher interest rates associated with the issuance of new long-term debt. Also contributing to the increase were $12 million associated with higher average interest rates on existing variable rate debt, a $6 million loss on the early redemption of long-term debt payable to affiliated trusts in January 2006, and a $16 million loss on the repayment of long-term debt payable to affiliated trusts in December 2006. The 2006 increase was partially offset by $4 million in lower other interest costs.

Income Taxes

Income taxes for these other businesses decreased $7 million in 2008 primarily as a result of leveraged lease losses discussed previously under "Leveraged Lease Income (Losses)," partially offset by a $36 million decrease in net synthetic fuel tax credits as a result of Southern Company terminating its investment in synthetic fuel projects at December 31, 2007. Income taxes increased $53 million in 2007 primarily as a result of a $30 million decrease in net synthetic fuel tax credits as a result of terminating Southern Company's membership interest in one of the synthetic fuel entities in 2006 and increasing the synthetic fuel tax credit reserves due to an anticipated phase-out of synthetic fuel tax credits due to higher oil prices. Income taxes increased $136 million in 2006 primarily as a result of a $111 million decrease in net synthetic fuel tax credits as a result of terminating Southern Company's membership interest in one of the synthetic fuel entities, curtailing production at the other synthetic fuel entity from May to September 2006, and increasing the synthetic fuel tax credit reserves due to an anticipated phase-out of synthetic fuel tax credits due to higher oil prices. See Note 5 to the financial statements under "Effective Tax Rate" for further information.

Effects of Inflation

The traditional operating companies and Southern Power are subject to rate regulation and party to long-term contracts that are generally based on the recovery of historical costs. When historical costs are included, or when inflation exceeds projected costs used in rate regulation or in market-based prices, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, the income tax laws are based on historical costs. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on Southern Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss or the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt, preferred securities, preferred stock, and preference stock. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the traditional operating companies' approved electric rates.

FUTURE EARNINGS POTENTIAL

General

The four traditional operating companies operate as vertically integrated utilities providing electricity to customers within their service areas in the Southeastern United States. Prices for electricity provided to retail customers are set by state PSCs under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the Federal Energy Regulatory Commission (FERC). Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Southern Power continues to focus on long-term capacity contracts, optimized by limited energy trading activities. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of Southern Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of Southern Company's primary business of selling electricity. These factors include the traditional operating companies' ability to maintain a constructive regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Other major factors include the profitability of the competitive wholesale supply business and federal regulatory policy which may impact Southern Company's level of participation in this market. Future earnings for the electricity business in the near term will depend, in part, upon maintaining energy sales during the current economic downturn, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities and other wholesale customers, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service area. In addition, the level of future earnings for the wholesale supply business also depends on numerous factors including creditworthiness of customers, total generating capacity available in the Southeast, and the successful remarketing of capacity as current contracts expire. Recent recessionary conditions have negatively impacted sales growth for the traditional operating companies and may negatively impact wholesale capacity revenues at Southern Power. The timing and extent of the economic recovery will impact future earnings.

Southern Company system generating capacity increased 659 megawatts due to Southern Power's completion of Franklin Unit 3 in June 2008. In general, Southern Company has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities or to meet requirements of Southern Company's regulated retail markets, both of which are optimized by limited energy trading activities. See FUTURE EARNINGS POTENTIAL – "Construction Projects" herein for additional information.

As part of its ongoing effort to adapt to changing market conditions, Southern Company continues to evaluate and consider a wide array of potential business strategies. These strategies may include business combinations, partnerships, acquisitions involving other utility or non-utility businesses or properties, disposition of certain assets, internal restructuring, or some combination thereof. Furthermore, Southern Company may engage in new business ventures that arise from competitive and regulatory changes in the utility industry. Pursuit of any of the above strategies, or any combination thereof, may significantly affect the business operations, risks, and financial condition of Southern Company.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental statutes and regulations are adopted or modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power. The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The action against Georgia Power has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case, and the ultimate outcome of these matters cannot be determined at this time.

Southern Company believes that the traditional operating companies complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in either of these cases could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

Southern Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating

costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2008, Southern Company had invested approximately $6.3 billion in capital projects to comply with these requirements, with annual totals of $1.6 billion, $1.5 billion, and $661 million for 2008, 2007, and 2006, respectively. The Company expects that capital expenditures to assure compliance with existing and new statutes and regulations will be an additional $1.4 billion, $737 million, and $871 million for 2009, 2010, and 2011, respectively. The Company's compliance strategy can be affected by changes to existing environmental laws, statutes, and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Compliance with any new federal or state legislation or regulations related to global climate change, air quality, combustion byproducts, including coal ash, or other environmental and health concerns could also significantly affect Southern Company. Although new or revised environmental legislation or regulations could affect many areas of Southern Company's operations, the full impact of any such changes cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for Southern Company. Through 2008, the Company had spent approximately $5.4 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently being installed at several plants to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2004, the EPA designated nonattainment areas under an eight-hour ozone standard. Areas within Southern Company's service area that were designated as nonattainment under the eight-hour ozone standard included Macon (Georgia), Birmingham (Alabama), and a 20-county area within metropolitan Atlanta. The Macon and Birmingham areas have since been redesignated as attainment areas by the EPA, and maintenance plans to address future exceedances of the standard have been approved for both areas. State plans for bringing the Atlanta area into attainment with this standard were due to the EPA in 2007; however, in December 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA rules designed to provide states with the guidance necessary to develop those plans. State plans could require additional reductions in NO_x emissions from power plants. On March 12, 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard which will likely result in designation of new nonattainment areas within Southern Company's service territory. The EPA is expected to publish those designations in 2010 and require state implementation plans for any nonattainment areas by 2013.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for several areas within Southern Company's service area in Alabama and Georgia. State plans for addressing the nonattainment designations for this standard were due by April 5, 2008 but have not been finalized. These state plans could require further reductions in SO_2 and NO_x emissions from power plants. In September 2006, the EPA published a final rule which increased the stringency of the 24-hour average fine particulate matter air quality standard. On December 18, 2008, the EPA designated the Birmingham, Alabama area as nonattainment for the 24-hour standard. A state implementation plan for this nonattainment area is due in 2012.

The EPA issued the final Clean Air Interstate Rule (CAIR) in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including each of the states within Southern Company's service area, are subject to the requirements of the rule. The rule calls for additional

reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating CAIR in its entirety and remanding it to the EPA for further action consistent with its opinion. On December 23, 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit altered its July decision in response to a rehearing petition and remanded CAIR to the EPA without vacatur, thereby leaving CAIR compliance requirements in place while the EPA develops a revised rule. States in the Southern Company service territory have completed plans to implement CAIR. Emission reductions are being accomplished by the installation of emission controls at Southern Company's coal-fired facilities and/or by the purchase of emission allowances. The full impact of the court's remand and the outcome of the EPA's future rulemaking in response cannot be determined at this time.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress by 2018 toward the natural conditions goal. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that CAIR satisfies BART requirements for SO_2 and NO_x. Extensive studies were performed for each of the Company's affected units to demonstrate that additional particulate matter controls are not necessary under BART. The states of Alabama and Mississippi have determined that no additional SO_2 controls beyond CAIR are needed to satisfy reasonable progress. At the request of the State of Georgia, additional analyses were performed for certain units in Georgia to demonstrate that no additional SO_2 controls were required to demonstrate reasonable progress. States have completed or are currently completing implementation plans that contain strategies for BART and any other measures required to achieve the first phase of reasonable progress.

The impacts of the eight-hour ozone nonattainment designations, the fine particulate matter nonattainment designations, and the Clean Air Visibility Rule on the Company cannot be determined at this time and will depend on the resolution of any pending legal challenges and the development and implementation of rules at the state level. For example, the State of Georgia has approved a "multi-pollutant rule" that requires plant-specific emission controls on all but the smallest generating units in Georgia to be installed according to a schedule set forth in the rule. The rule is designed to ensure reductions in emissions of SO_2, NO_x, and mercury in Georgia.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2 and NO_x emission controls within the next several years to ensure continued compliance with applicable air quality requirements.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The final Clean Air Mercury Rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners alleged that the EPA was not authorized to establish a cap-and-trade program for mercury emissions and instead the EPA must establish maximum achievable control technology standards for coal-fired electric utility steam generating units. On February 8, 2008, the court ruled in favor of the petitioners and vacated the Clean Air Mercury Rule. The Company's overall environmental compliance strategy relies primarily on a combination of SO_2 and NOx controls to reduce mercury emissions. Any significant changes in the strategy will depend on the outcome of any appeals and/or future federal and state rulemakings. Future rulemakings necessitated by the court's decision could require emission reductions more stringent than those required by the Clean Air Mercury Rule.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. In January 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to the EPA for revisions. The decision has been appealed to the U.S. Supreme Court. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot be determined at this time.

Environmental Remediation

Southern Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the traditional operating companies could incur substantial costs to clean up properties. The traditional operating companies conduct studies to determine the extent of any required cleanup and have recognized in their respective financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The traditional operating companies may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions and renewable energy standards continue to be strongly considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. The ultimate outcome of these proposals cannot be determined at this time; however, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that will follow from this response may have implications for both new and existing stationary sources, such as power plants. The ultimate outcome of these rulemaking activities cannot be determined at this time; however, as with the current legislative proposals, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In addition, some states are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. For example, on June 25, 2008, Florida's Governor signed comprehensive energy-related legislation that includes authorization for the Florida Department of Environmental Protection to adopt rules for a cap-and-trade regulatory program to address greenhouse gas emissions from electric utilities, conditioned upon their ratification by the legislature no sooner than the 2010 legislative session. This legislation also authorizes the Florida PSC to adopt a renewable portfolio standard for public utilities, subject to legislative ratification. The impact of this and any similar legislation on Southern Company will depend on the future development, adoption, legislative ratification,

implementation, and potential legal challenges to rules governing greenhouse gas emissions and mandates regarding the use of renewable energy, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2012 timeframe, with a conclusion to this round of negotiations targeted for the end of 2009. The outcome and impact of the international negotiations cannot be determined at this time.

The Company is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. These include new nuclear generation, including proposed construction of two additional generating units at Plant Vogtle in Georgia; proposed construction of an advanced IGCC unit with approximately 50% carbon capture in Kemper County, Mississippi; and renewables investments, including the proposed conversion of Plant Mitchell in Georgia from coal-fired to biomass generation. The Company is currently considering additional projects and is pursuing research into the costs and viability of other renewable technologies for the Southeast.

FERC Matters

Market-Based Rate Authority

Each of the traditional operating companies and Southern Power has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by any subsidiary of Southern Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the traditional operating companies and Southern Power to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $19.7 million, plus interest. Southern Company and its subsidiaries believe that there is no meritorious basis for an adverse decision in this proceeding and are vigorously defending themselves in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability

obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Generation Interconnection Agreements

In November 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, filed complaints at the FERC requesting that the FERC modify the agreements and that those Southern Company subsidiaries refund a total of $19 million previously paid for interconnection facilities. No other similar complaints are pending with the FERC.

In January 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order required the modification of Tenaska's interconnection agreements, under the provisions of the order, Southern Company determined that no refund was payable to Tenaska. Southern Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of FERC's methodology for determining the amount of refunds. The requested rehearings were denied, and Southern Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

PSC Matters

Alabama Power

Effective January 2007 and thereafter, Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Retail rate adjustments for any two-year period, when averaged together, cannot exceed 4% per year and any annual adjustment is limited to 5%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13.0% and 14.5%. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range.

On October 7, 2008, the Alabama PSC approved a corrective rate package primarily providing for adjustments associated with customer charges to certain existing rate structures. This package, effective in January 2009, is expected to generate additional annual revenues of approximately $168 million. Alabama Power agreed to a moratorium on any increase in 2009 under Rate RSE. Alabama Power also agreed to defer any increase in rates during 2009 under the portion of Rate Certificated New Plant which permits recovery of costs associated with environmental laws and regulations until 2010. The deferral of the retail rate adjustments will have no significant effect on Southern Company's revenues or net income, but will have an immaterial impact on annual cash flows. On December 1, 2008, Alabama Power made its submission of projected data for calendar year 2009. See Note 3 to the financial statements under "Alabama Power Retail Regulatory Matters" for further information.

Georgia Power

In December 2007, the Georgia PSC approved the retail rate plan for the years 2008 through 2010 (2007 Retail Rate Plan). Under the 2007 Retail Rate Plan, Georgia Power's earnings will continue to be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be applied to rate refunds with the remaining one-third applied to an environmental compliance cost recovery (ECCR) tariff. Georgia Power has agreed that it will not file for a general base rate increase during this period unless its projected retail ROE falls below 10.25%. Retail base rates increased by approximately $99.7 million effective January 1, 2008 to provide for cost recovery of transmission, distribution, generation, and other investments, as well as increased operating costs. In addition, the ECCR tariff was implemented to allow for the recovery of costs for required environmental projects mandated by state and federal regulations. The ECCR tariff increased rates by approximately $222 million effective January 1, 2008. Georgia Power is required to file a general rate case by July 1, 2010, in response to which the Georgia PSC would be expected to determine whether the 2007 Retail Rate Plan should be continued, modified, or discontinued. See Note 3 to the financial statements under "Georgia Power Retail Regulatory Matters" for additional information.

Fuel Cost Recovery

The traditional operating companies each have established fuel cost recovery rates approved by their respective state PSCs. Over the past several years, the traditional operating companies have continued to experience higher than expected fuel costs for coal, natural gas, and uranium. The traditional operating companies continuously monitor the under recovered fuel cost balance in light of these higher fuel costs. Each of the traditional operating companies received approval in 2007 and/or 2008 to increase its fuel cost recovery factor to recover existing under recovered amounts as well as projected future costs. At December 31, 2008, the amount of under recovered fuel costs included in the balance sheets was $1.2 billion compared to $1.1 billion at December 31, 2007.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changing the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. Based on their respective state PSC orders, a portion of the under recovered regulatory clause revenues for Alabama Power and Georgia Power was reclassified from current assets to deferred charges and other assets in the balance sheets. See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Alabama Power Retail Regulatory Matters", "Georgia Power Retail Regulatory Matters", and "Gulf Power Retail Regulatory Matters" for additional information.

Storm Damage Cost Recovery

Each traditional operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In addition, each of the traditional operating companies has been authorized by its state PSC to defer the portion of the major storm restoration costs that exceeded the balance in its storm damage reserve account. As of December 31, 2008, the under recovered balance in Southern Company's storm damage reserve accounts totaled approximately $27 million, of which approximately $21 million and $6 million, respectively, are included in the balance sheets herein under "Other Current Assets" and "Other Regulatory Assets."

See Notes 1 and 3 to the financial statements under "Storm Damage Reserves" and "Storm Damage Cost Recovery," respectively, for additional information on these reserves. The final outcome of these matters cannot now be determined.

Mississippi Base Load Construction Legislation

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor on May 9, 2008 to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. The effect of this legislation on Southern Company cannot now be determined.

Mirant Matters

Mirant was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and selected other countries. It was a wholly-owned subsidiary of Southern Company until its initial public offering in October 2000. In April 2001, Southern Company completed a spin-off to its shareholders of its remaining ownership, and Mirant became an independent corporate entity.

In July 2003, Mirant and certain of its affiliates filed for voluntary reorganization under Chapter 11 of the Bankruptcy Code. In January 2006, Mirant's plan of reorganization became effective, and Mirant emerged from bankruptcy. As part of the plan, Mirant transferred substantially all of its assets and its restructured debt to a new corporation that adopted the name Mirant Corporation (Reorganized Mirant). Southern Company has certain contingent liabilities associated with guarantees of contractual commitments made by Mirant's subsidiaries discussed in Note 7 to the financial statements under "Guarantees" and with various lawsuits discussed in Note 3 to the financial statements under "Mirant Matters."

In December 2004, as a result of concluding an IRS audit for the tax years 2000 and 2001, Southern Company paid approximately $39 million in additional tax and interest related to Mirant tax items and filed a claim in Mirant's bankruptcy case for that amount. Through December 2008, Southern Company received from the IRS approximately $38 million in refunds related to Mirant. Southern Company believes it has a right to recoup the $39 million tax payment owed by Mirant from such tax refunds. As a result, Southern Company intends to retain the tax refunds and reduce its claim against Mirant for the payment of Mirant taxes by the amount of such refunds. MC Asset Recovery, a special purpose subsidiary of Reorganized Mirant, has objected to and sought to equitably subordinate the Southern Company tax claim in its fraudulent transfer litigation against Southern Company. Southern Company has reserved the remaining amount with respect to its Mirant tax claim.

If Southern Company is ultimately required to make any additional payments either with respect to the IRS audit or its contingent obligations under guarantees of Mirant subsidiaries, Mirant's indemnification obligation to Southern Company for these additional payments, if allowed, would constitute unsecured claims against Mirant, entitled to stock in Reorganized Mirant. See Note 3 to the financial statements under "Mirant Matters – Mirant Bankruptcy."

In June 2005, Mirant, as a debtor in possession, and The Official Committee of Unsecured Creditors of Mirant Corporation filed a complaint against Southern Company in the U.S. Bankruptcy Court for the Northern District of Texas, which was amended in July 2005, February 2006, May 2006, and March 2007. In January 2006, MC Asset Recovery was substituted as plaintiff. The fourth amended complaint (the complaint) alleges that Southern Company caused Mirant to engage in certain fraudulent transfers and to pay illegal dividends to Southern Company

prior to the spin-off. The complaint also seeks to recharacterize certain advances from Southern Company to Mirant for investments in energy facilities from debt to equity. The complaint further alleges that Southern Company is liable to Mirant's creditors for the full amount of Mirant's liability under an alter ego theory of recovery and that Southern Company breached its fiduciary duties to Mirant and its creditors, caused Mirant to breach its fiduciary duties to creditors, and aided and abetted breaches of fiduciary duties by Mirant's directors and officers. The complaint also seeks recoveries under the theories of restitution and unjust enrichment. In addition, the complaint alleged a claim under the Federal Debt Collection Procedure Act (FDCPA) to avoid certain transfers from Mirant to Southern Company; however, on July 7, 2008, the court ruled that the FDCPA does not apply and that Georgia law should apply instead. The complaint seeks monetary damages in excess of $2 billion plus interest, punitive damages, attorneys' fees, and costs. Finally, the complaint includes an objection to Southern Company's pending claims against Mirant in the Bankruptcy Court (which relate to reimbursement under the separation agreements of payments such as income taxes, interest, legal fees, and other guarantees described in Note 7 to the financial statements) and seeks equitable subordination of Southern Company's claims to the claims of all other creditors. Southern Company served an answer to the complaint in April 2007.

In February 2006, the Company's motion to transfer the case to the U.S. District Court for the Northern District of Georgia was granted. In May 2006, Southern Company filed a motion for summary judgment seeking entry of judgment against the plaintiff as to all counts in the complaint. In December 2006, the U.S. District Court for the Northern District of Georgia granted in part and denied in part the motion. As a result, certain breach of fiduciary duty claims alleged in earlier versions of the complaint were barred; all other claims were allowed to proceed. On August 6, 2008, Southern Company filed a second motion for summary judgment. MC Asset Recovery filed its response to Southern Company's motion for summary judgment on October 20, 2008. On February 5, 2009, the court denied the summary judgment motion in connection with the fraudulent conveyance and illegal dividend claims concerning certain advance return/loan repayments in 1999, dividends in 1999 and 2000, and transfers in connection with Mirant's separation from Southern Company. The court granted Southern Company's motion for summary judgment with respect to certain claims, including claims for restitution and unjust enrichment, claims that Southern Company aided and abetted Mirant's directors' breach of fiduciary duties to Mirant, and claims that Southern Company used Mirant as an alter ego. In addition, the court granted Southern Company's motion in connection with the fraudulent transfer and illegal dividend claims concerning certain turbine termination payments. Southern Company believes there is no meritorious basis for the claims in the complaint and is vigorously defending itself in this action. See Note 3 to the financial statements under "Mirant Matters – MC Asset Recovery Litigation" for additional information. The ultimate outcome of these matters cannot be determined at this time.

Mirant Securities Litigation

In November 2002, Southern Company, certain former and current senior officers of Southern Company, and 12 underwriters of Mirant's initial public offering were added as defendants in a class action lawsuit that several Mirant shareholders originally filed against Mirant and certain Mirant officers in May 2002. Several other similar lawsuits filed subsequently were consolidated into this litigation in the U.S. District Court for the Northern District of Georgia. The amended complaint is based on allegations related to alleged improper energy trading and marketing activities involving the California energy market, alleged false statements and omissions in Mirant's prospectus for its initial public offering and in subsequent public statements by Mirant, and accounting-related issues previously disclosed by Mirant. The lawsuit purports to include persons who acquired Mirant securities between September 26, 2000 and September 5, 2002.

In July 2003, the court dismissed all claims based on Mirant's alleged improper energy trading and marketing activities involving the California energy market. The other claims do not allege any improper trading and marketing activity, accounting errors, or material misstatements or omissions on the part of Southern Company but seek to impose liability on Southern Company based on allegations that Southern Company was a "control person"

as to Mirant prior to the spin-off date. Southern Company filed an answer to the consolidated amended class action complaint in September 2003. Plaintiffs also filed a motion for class certification.

During Mirant's Chapter 11 proceeding, the securities litigation was stayed, with the exception of limited discovery. Since Mirant's plan of reorganization has become effective, the stay has been lifted. In March 2006, the plaintiffs filed a motion for reconsideration requesting that the court vacate that portion of its July 2003 order dismissing the plaintiffs' claims based upon Mirant's alleged improper energy trading and marketing activities involving the California energy market. Southern Company and the other defendants opposed the plaintiffs' motion. In March 2007, the court granted plaintiffs' motion for reconsideration, reinstated the California energy market claims, and granted in part and denied in part defendants' motion to compel certain class certification discovery. In March 2007, defendants filed renewed motions to dismiss the California energy claims on grounds originally set forth in their 2003 motions to dismiss, but which were not addressed by the court. In July 2007, certain defendants, including Southern Company, filed motions for reconsideration of the court's denial of a motion seeking dismissal of certain federal securities laws claims based upon, among other things, certain alleged errors included in financial statements issued by Mirant. On August 6, 2008, the court entered an order in regard to the defendants' motions to dismiss and for partial summary judgment. The court granted the defendants' motion for partial summary judgment in two respects concluding that certain holders of Mirant stock do not have standing under the securities laws. The court denied the defendants' other motions and granted leave to the plaintiffs to re-plead their claims against the defendants. In accordance with the court's order, the plaintiffs filed an amended complaint. The plaintiffs added allegations based upon claims asserted against Southern Company in the MC Asset Recovery litigation. Southern Company and the remaining defendants filed motions to dismiss the amended complaint on October 9, 2008. On January 7, 2009, the trial judge dismissed all counts of the plaintiffs' second amended complaint with prejudice. This matter is now concluded.

Income Tax Matters

Legislation

On February 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA include an extension of bonus depreciation and multiple renewable energy incentives. These incentives could have a significant impact on Southern Company's future cash flow and net income. Additionally, the ARRA includes programs for renewable energy, transmission and smart grid enhancement, fossil energy and research, and energy efficiency and conservation. The ultimate impact cannot be determined at this time.

Georgia State Income Tax Credits

Georgia Power's 2005 through 2008 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. Georgia Power has also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue has not responded to these claims. In July 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. An unrecognized tax benefit has been recorded related to these credits. If Georgia Power prevails, these claims could have a significant, and possibly material, positive effect on Southern Company's net income. If Georgia Power is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on Southern Company's cash flow. The ultimate outcome of this matter cannot now be determined.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the Internal Revenue Code Section 199 (production activities deduction). The

deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The IRS has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, Southern Company reversed the unrecognized tax benefit and adjusted the deduction to conform to the agreement. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Construction Projects

Integrated Coal Gasification Combined Cycle

On January 16, 2009, Mississippi Power filed for a Certificate of Public Convenience and Necessity with the Mississippi PSC to allow construction of a new electric generating plant located in Kemper County, Mississippi. The plant would utilize an advanced coal IGCC with an output capacity of 582 megawatts. The Kemper IGCC will use locally mined lignite (an abundant, lower heating value coal) from a proposed mine adjacent to the plant as fuel. This certificate, if approved by the Mississippi PSC, would authorize Mississippi Power to acquire, construct and operate the Kemper IGCC and related facilities. The Kemper IGCC, subject to federal and state environmental reviews and certain regulatory approvals, is expected to begin commercial operation in November 2013. As part of its filing, Mississippi Power has requested certain rate recovery treatment in accordance with the base load construction legislation. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Mississippi Base Load Construction Legislation" herein for additional information.

Mississippi Power filed an application in June 2006 with the U.S. Department of Energy (DOE) for certain tax credits available to projects using clean coal technologies under the Energy Policy Act of 2005. The DOE subsequently certified the Kemper IGCC, and in November 2006 the IRS allocated Internal Revenue Code Section 48A tax credits of $133 million to Mississippi Power. The utilization of these credits is dependent upon meeting the certification requirements for the Kemper IGCC, including an in-service date no later than November 2013. Mississippi Power has secured all environmental reviews and permits necessary to commence construction of the Kemper IGCC and has entered into a binding contract for the steam turbine generator, completing two milestone requirements for the Section 48A credits.

On February 14, 2008, Mississippi Power also requested that the DOE transfer the remaining funds previously granted to a cancelled Southern Company project that would have been located in Orlando, Florida. On December 12, 2008, an agreement was reached to assign the remaining funds to the Kemper IGCC. The estimated construction cost of the Kemper IGCC is approximately $2.2 billion, which is net of $220 million related to funding to be received from the DOE related to project construction. The remaining DOE funding of $50 million is projected to be used for demonstration over the first few years of operation.

Beginning in December 2006, the Mississippi PSC has approved Mississippi Power's requested accounting treatment to defer the costs associated with Mississippi Power's generation resource planning, evaluation, and screening activities as a regulatory asset. On December 22, 2008, Mississippi Power requested an amendment to its original order that would allow these costs to continue to be charged to and remain in a regulatory asset until January 1, 2010. In its application, Mississippi Power reported that it anticipated spending approximately $61 million by or before May 31, 2009. At December 31, 2008, Mississippi Power had spent $42.3 million of the $61 million, of which $3.7 million related to land purchases capitalized. Of the remaining amount, $0.8 million was expensed and $37.8 million was deferred in other regulatory assets.

The final outcome of this matter cannot now be determined.

Nuclear

In August 2006, Southern Nuclear, on behalf of Georgia Power, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners (collectively, Owners), filed an application with the Nuclear Regulatory Commission (NRC) for an early site permit relating to two additional nuclear units on the site of Plant Vogtle. See Note 4 to the financial statements for additional information on these co-owners. On March 31, 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units.

On April 8, 2008, Georgia Power, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners will pay a purchase price that will be subject to certain price escalation and adjustments, adjustments for change orders, and performance bonuses. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share, based on its current ownership interest, is 45.7%. Under the terms of a separate joint development agreement, the Owners finalized their ownership percentages on July 2, 2008, except for allowed changes, under certain limited circumstances, during the Georgia PSC certification process.

On August 1, 2008, Georgia Power submitted an application for the Georgia PSC to certify the project. Hearings began November 3, 2008 and a final certification decision is expected in March 2009.

If certified by the Georgia PSC and licensed by the NRC, Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively. The total plant value to be placed in service will also include financing costs for each of the Owners, the impacts of inflation on costs, and transmission and other costs that are the responsibility of the Owners. Georgia Power's proportionate share of the estimated in-service costs, based on its current ownership interest, is approximately $6.4 billion, subject to adjustments and performance bonuses under the Vogtle 3 and 4 Agreement.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Owners and the Consortium also have agreed to certain bonuses payable to the Consortium for early completion and unit performance. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

The obligations of Westinghouse Electric Company LLC and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Vogtle 3 and 4 Agreement is subject to certification by the Georgia PSC. In addition, the Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or

delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In connection with the certification application, Georgia Power has requested Georgia PSC approval to include the construction work in progress accounts for Plant Vogtle Units 3 and 4 in rate base and allow Georgia Power to recover financing costs during the construction period.

On February 11, 2009, the Georgia State Senate passed Senate Bill 31 that would allow the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. A similar bill is being considered in the Georgia State House of Representatives.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy was organized to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs. COLs for the two reactor designs were submitted to the NRC during the fourth quarter of 2007. The COLs ultimately are expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Southern Company is also exploring other possibilities relating to additional nuclear power projects, both on its own or in partnership with other utilities.

The final outcome of these matters cannot now be determined.

Nuclear Relicensing

The NRC operating licenses for Plant Vogtle Units 1 and 2 currently expire in January 2027 and February 2029, respectively. In June 2007, Georgia Power filed an application with the NRC to extend the licenses for Plant Vogtle Units 1 and 2 for an additional 20 years. Georgia Power anticipates the NRC may make a decision regarding the license extension for Plant Vogtle in 2009.

Other Matters

Georgia Power has initiated a voluntary attrition plan under which participating employees may elect to resign from their positions as of March 31, 2009. Approximately 700 employees who have indicated an interest in participating in the plan have been selected by Georgia Power and are permitted to resign and receive severance. Each participating employee who resigns under the plan will be entitled to receive a severance payment equal to his or her annual base salary, accrued vacation, and pro-rated bonus as of March 31, 2009. Southern Company will record a charge during the first quarter 2009 in connection with the plan. The ultimate amount of the charge will be dependent on the total number of employees who elect to resign under the plan. Such charge could have a material impact on Southern Company's statements of income for the quarter ending March 31, 2009 and statements of cash flow for the six months ending June 30, 2009. The first quarter 2009 charge will generally be offset with lower salary costs for the remainder of the year and is not expected to have a material impact on Southern Company's financial statements for the year ending December 31, 2009.

Southern Company is involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. In addition, Southern Company is subject to certain claims and legal actions arising in the ordinary course of business. Southern Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and

claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Southern Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

Southern Company prepares its consolidated financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on Southern Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has discussed the development and selection of the critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

Southern Company's traditional operating companies, which comprised approximately 95% of Southern Company's total operating revenues for 2008, are subject to retail regulation by their respective state PSCs and wholesale regulation by the FERC. These regulatory agencies set the rates the traditional operating companies are permitted to charge customers based on allowable costs. As a result, the traditional operating companies apply FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the traditional operating companies; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

Southern Company and its subsidiaries are subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject them to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. Southern Company periodically evaluates its exposure to such risks and, in

accordance with generally accepted accounting principles, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect Southern Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or state revenue department interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which Southern Company or its subsidiaries may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which Southern Company or its subsidiaries may be named as a defendant.
- Resolution or progression of new or existing matters through the legislative process, the court systems, the IRS, the FERC, or the EPA.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, and power delivery volume and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

New Accounting Standards

Business Combinations

In December 2007, the FASB issued FASB Statement No. 141 (revised 2007), "Business Combinations" (SFAS No. 141R). Southern Company adopted SFAS No. 141R on January 1, 2009. The adoption of SFAS No. 141R could have an impact on the accounting for any business combinations completed by Southern Company after January 1, 2009.

In December 2007, the FASB issued FASB Statement No. 160, "Non-controlling Interests in Consolidated Financial Statements" (SFAS No. 160). SFAS No. 160 amends Accounting Research Bulletin No. 51, "Consolidated Financial Statements" to establish accounting and reporting standards for the non-controlling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a non-controlling interest in a subsidiary should be reported as equity in the consolidated financial statements and establishes a single method of accounting for changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation. Southern Company adopted SFAS No. 160 on January 1, 2009 with no material impact to the financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

Southern Company's financial condition remained stable at December 31, 2008. Throughout the recent turmoil in the financial markets, Southern Company has maintained adequate access to capital without drawing on any of its committed bank credit arrangements used to support its commercial paper programs and variable rate pollution control revenue bonds. Southern Company and the traditional operating companies have continued to issue commercial paper at reasonable rates. Southern Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. No material changes in bank credit arrangements have occurred although market rates for committed credit have increased and the Company may be subject to higher costs as its existing facilities are replaced or renewed. Southern Company's interest cost for short-term debt has decreased as market short-term interest rates have declined. The ultimate impact on future financing costs as a result of the financial turmoil cannot be determined at this time. Southern Company experienced no material counterparty credit losses as a result of the turmoil in the financial markets. See "Sources of Capital" and "Financing Activities" herein for additional information.

Southern Company's investments in pension and nuclear decommissioning trust funds declined in value as of December 31, 2008. Southern Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time. Southern Company does not expect any changes to funding obligations to the nuclear decommissioning trusts at this time.

Net cash provided from operating activities in 2008 totaled $3.4 billion, an increase of $3 million as compared to 2007. Significant changes in operating cash flow for 2008 included a $264 million increase in the use of funds for fossil fuel inventory as compared to 2007. This use of funds was offset by an increase in cash of $312 million in accrued taxes primarily due to a difference between the periods in payments for federal taxes and property taxes. Net cash provided from operating activities in 2007 totaled $3.4 billion, an increase of $575 million as compared to 2006. The increase was primarily due to an increase in net income as previously discussed, an increase in cash collections from previously deferred fuel and storm damage costs, and a reduction in cash outflows compared to the previous year in fossil fuel inventory. In 2006, net cash provided from operating activities totaled $2.8 billion, an increase over the previous year of $290 million, primarily as a result of a decrease in under recovered storm restoration costs, a decrease in accounts payable from year-end 2005 amounts that included substantial hurricane-related expenditures, partially offset by an increase in fossil fuel inventory.

Net cash used for investing activities in 2008 totaled $4.1 billion primarily due to property additions to utility plant of $4.0 billion. Net cash used for investing activities in 2007 totaled $3.7 billion primarily due to property additions to utility plant of $3.5 billion. In 2006, net cash used for investing activities was $2.8 billion primarily due to property additions to utility plant of $3.0 billion, partially offset by proceeds from the sale of Southern Company Gas LLC and the receipt by Mississippi Power of capital grant proceeds related to Hurricane Katrina.

Net cash provided from financing activities totaled $944 million in 2008 primarily due to long-term debt issuances. Net cash provided from financing activities totaled $348 million in 2007 primarily due to replacement of short-term debt with longer term financing and cash raised from common stock programs. In 2006, net cash used for financing activities was $21 million.

Significant balance sheet changes in 2008 include an increase in total property, plant, and equipment of $2.5 billion and an increase in long-term debt, excluding amounts due within one year, of $2.7 billion used primarily for construction expenditures and general corporate purposes. Other significant balance sheet changes which are

primarily attributable to the decline in market value of the Company's pension trust fund include a decrease of $2.4 billion in prepaid pension costs, an increase of $1.9 billion in other regulatory assets, and a decrease of $1.3 billion in other regulatory liabilities.

At the end of 2008, the closing price of Southern Company's common stock was $37.00 per share, compared with book value of $17.08 per share. The market-to-book value ratio was 217% at the end of 2008, compared with 239% at year-end 2007.

Southern Company, each of the traditional operating companies, and Southern Power have received investment grade credit ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and/or preference stock. SCS has an investment grade corporate credit rating.

Sources of Capital

Southern Company intends to meet its future capital needs through internal cash flow and external security issuances. Equity capital can be provided from any combination of the Company's stock plans, private placements, or public offerings. The amount and timing of additional equity capital to be raised in 2009, as well as in subsequent years, will be contingent on Southern Company's investment opportunities.

The traditional operating companies and Southern Power plan to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the type and timing of any financings, if needed, will depend upon prevailing market conditions, regulatory approval, and other factors. The issuance of securities by the traditional operating companies is generally subject to the approval of the applicable state PSC. In addition, the issuance of all securities by Mississippi Power and Southern Power and short-term securities by Georgia Power is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, Southern Company and certain of its subsidiaries file registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the appropriate regulatory authorities, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Southern Company, each traditional operating company, and Southern Power obtain financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of each company are not commingled with funds of any other company.

Southern Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs as well as scheduled maturities of long-term debt. To meet short-term cash needs and contingencies, Southern Company has substantial cash flow from operating activities and access to capital markets, including commercial paper programs (which are backed by bank credit facilities).

At December 31, 2008, Southern Company and its subsidiaries had approximately $417 million of cash and cash equivalents and $4.2 billion of unused credit arrangements with banks, of which $970 million expire in 2009, $25 million expire in 2011, and $3.2 billion expire in 2012. Approximately $84 million of the credit facilities expiring in 2009 allow for the execution of term loans for an additional two-year period, and $544 million allow for the execution of one-year term loans. Most of these arrangements contain covenants that limit debt levels and typically contain cross default provisions that are restricted only to the indebtedness of the individual company. Southern Company and its subsidiaries are currently in compliance with all such covenants. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Financing Activities

During 2008, Southern Company and its subsidiaries issued $2.5 billion of senior notes and $566 million of obligations related to pollution control revenue bonds. In addition, Georgia Power, Gulf Power, and Mississippi Power entered into long-term bank loans of $300 million, $110 million, and $80 million, respectively. Georgia Power and Gulf Power also entered into short-term bank loans of $100 million and $50 million, respectively. Interest rate hedges of $405 million notional amount were settled at a loss of $26 million related to the issuances. Southern Company issued $474 million of common stock through the Southern Company Investment Plan and employee and director stock plans. The security issuances were used to redeem or repay at maturity $1.5 billion of long-term debt, to reduce short-term indebtedness, to fund Southern Company's ongoing construction program, and for general corporate purposes. Additionally, interest rate hedges of $100 million were settled early at a loss of $2 million related to counterparty credit issues.

Also in 2008, the traditional operating companies converted their entire $1.2 billion of obligations related to auction rate pollution control revenue bonds from auction rate modes to other interest rate modes. Initially, approximately $696 million of the auction rate pollution control revenue bonds were converted to fixed interest rate modes and approximately $553 million were converted to variable rate modes. In June 2008, approximately $98 million of the variable rate pollution control revenue bonds were converted to fixed interest rate modes.

During the third quarter 2008, Alabama Power, Georgia Power, and Mississippi Power were required to purchase a total of approximately $96 million of variable rate pollution control revenue bonds that were tendered by investors. Alabama Power and Mississippi Power remarketed all of their repurchased variable rate pollution control revenue bonds of $11 million and $8 million, respectively. Georgia Power remarketed $75 million of its $77 million of tendered bonds. The remaining $2 million were extinguished.

In the fourth quarter 2008, Georgia Power and Gulf Power converted a total of approximately $171 million of variable rate pollution control revenue bonds to fixed interest rate modes.

Subsequent to December 31, 2008, Georgia Power issued $500 million of Series 2009A 5.95% Senior Notes due February 1, 2039. The proceeds were used to repay $150 million of its Series U Floating Rate Senior Notes at maturity, to repay short-term indebtedness, and for other general corporate purposes. Georgia Power settled $100 million of hedges related to the issuance at a loss of approximately $16 million.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, Southern Company and its subsidiaries plan to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Off-Balance Sheet Financing Arrangements

In 2001, Mississippi Power began the initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel for approximately $370 million. In 2003, the generating facility was acquired by Juniper Capital L.P. (Juniper), a limited partnership whose investors are unaffiliated with Mississippi Power. Simultaneously, Juniper entered into a restructured lease agreement with Mississippi Power. Juniper has also entered into leases with other parties unrelated to Mississippi Power. The assets leased by Mississippi Power comprise less than 50% of Juniper's assets. Mississippi Power is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The lease also provides for a residual value guarantee, approximately 73% of the acquisition cost, by Mississippi Power that is due upon termination of the lease in the event that Mississippi Power does not renew the lease or purchase the assets and that the fair market value is less than the unamortized cost of the assets. See Note 7 to the financial statements under "Operating Leases" for additional information.

Credit Rating Risk

Southern Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change of certain subsidiaries to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and construction of new generation. At December 31, 2008, the maximum potential collateral requirements under these contracts at a BBB and Baa2 rating were approximately $9 million and at a BBB- and/or Baa3 rating were approximately $395 million. At December 31, 2008, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $1.8 billion. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Southern Company is exposed to market risks, primarily commodity price risk and interest rate risk. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to a change in interest rates, the Company enters into forward starting interest rate swaps and other derivatives that have been designated as hedges. Derivatives outstanding at December 31, 2008 have a notional amount of $1.4 billion and are related to anticipated debt issuances and various floating rate obligations over the next two years. The weighted average interest rate on $1.6 billion of long-term variable interest rate exposure that has not been hedged at January 1, 2009 was 2.45%. If Southern Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $16 million at January 1, 2009. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Due to cost-based rate regulation, the traditional operating companies continue to have limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. In addition, Southern Power's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. To mitigate residual risks relative to movements in electricity prices, the traditional operating companies enter into physical fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The traditional operating companies continue to manage fuel-hedging programs implemented per the guidelines of their respective state PSCs.

The changes in fair value of energy-related derivative contracts were as follows at December 31:

	2008 Changes	2007 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ 4**	$(82)
Contracts realized or settled	**(150)**	80
Current period changes[a]	**(139)**	6
Contracts outstanding at the end of the period, assets (liabilities), net	**$(285)**	$4

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The decrease in the fair value positions of the energy-related derivative contracts for the year-ended December 31, 2008 was $289 million, substantially all of which is due to natural gas positions. This change is attributable to both the volume and prices of natural gas. At December 31, 2008, Southern Company had a net hedge volume of 148.9 billion cubic feet (Bcf) with a weighted average contract cost approximately $1.97 per million British thermal units (mmBtu) above market prices, compared to 99.0 Bcf at December 31, 2007 with a weighted average contract cost approximately $0.01 per mmBtu above market prices. The majority of the natural gas hedges are recorded through the traditional operating companies' fuel cost recovery clauses.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

	2008	2007
	(in millions)	
Regulatory hedges	**$(288)**	$ -
Cash flow hedges	**(1)**	1
Non-accounting hedges	**4**	3
Total fair value	**$(285)**	$4

Energy-related derivative contracts which are designated as regulatory hedges relate to the traditional operating companies' fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Unrealized pre-tax gains/(losses) recognized in income for energy-related derivative contracts that are not hedges were not material for any year presented.

The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

	December 31, 2008 Fair Value Measurements			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ -	$ -	$ -	$ -
Level 2	(285)	(203)	(77)	(5)
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(285)	$(203)	$(77)	$(5)

As part of the adoption of FASB Statement No. 157, "Fair Value Measurements" to increase consistency and comparability in fair value measurements and related disclosures, the table above now uses the three-tier fair value hierarchy, as discussed in Note 10 to the financial statements, as opposed to the previously used descriptions "actively quoted," "external sources," and "models and other methods." The three-tier fair value hierarchy focuses on the fair value of the contract itself, whereas the previous descriptions focused on the source of the inputs. Because Southern Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, the valuations of those contracts now appear in Level 2; previously they were shown as "actively quoted."

Southern Company is exposed to market risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. Southern Company's practice is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, Southern Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

During 2006 and 2007, Southern Company had derivatives in place to reduce its exposure to a phase-out of certain income tax credits related to synthetic fuel production in 2007. In accordance with Internal Revenue Code Section 45K, these tax credits were subject to limitation as the annual average price of oil increased. Because these transactions were not designated as hedges, the gains and losses were recognized in the statements of income as incurred. These derivatives settled on January 1, 2008 and thus there was no income statement impact for the year ended December 31, 2008. For 2007 and 2006, the fair value gain/(loss) recognized in other income/(expense) to mark the transactions to market was $27 million and $(32) million, respectively. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of Southern Company is currently estimated to be $5.7 billion for 2009, $5.1 billion for 2010, and $5.8 billion for 2011. These estimates include costs for new generation construction. Environmental expenditures included in these estimated amounts are $1.4 billion, $737 million, and $871 million for 2009, 2010, and 2011, respectively. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of NRC requirements, Alabama Power and Georgia Power have external trust funds for nuclear decommissioning costs; however, Alabama Power currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, Southern Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the traditional operating companies' respective regulatory commissions.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2009	2010-2011	2012-2013	After 2013	Uncertain Timing[d]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$ 617	$ 1,972	$2,745	$12,119	$ -	$17,453
Interest	858	1,616	1,424	11,102	-	15,000
Preferred and preference stock dividends[b]	65	130	130	-	-	325
Other derivative obligations[c] –						
Energy-related	224	78	5	-	-	307
Interest	21	-	-	-	-	21
Operating leases	143	212	81	146	-	582
Unrecognized tax benefits and interest[d]	145	-	-	-	16	161
Purchase commitments[e] –						
Capital[f]	5,467	10,644	-	-	-	16,111
Limestone[g]	13	70	72	144	-	299
Coal	4,608	5,999	2,602	3,421	-	16,630
Nuclear fuel	187	301	275	43	-	806
Natural gas[h]	1,507	1,609	1,242	3,798	-	8,156
Purchased power	217	455	413	1,938	-	3,023
Long-term service agreements[i]	85	203	255	1,731	-	2,274
Trusts –						
Nuclear decommissioning	3	7	7	53	-	70
Postretirement benefits[j]	56	116	-	-	-	172
Total	$14,216	$23,412	$9,251	$34,495	$16	$81,390

(a) All amounts are reflected based on final maturity dates. Southern Company and its subsidiaries plan to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2009, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 6 to the financial statements.

(d) The timing related to the $16 million in unrecognized tax benefits and interest payments in individual years beyond 12 months cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. See Notes 3 and 5 to the financial statements for additional information.

(e) Southern Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2008, 2007, and 2006 were $3.8 billion, $3.7 billion, and $3.5 billion, respectively.

(f) Southern Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures excluding those amounts related to contractual purchase commitments for nuclear fuel. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of Southern Company's program to reduce sulfur dioxide emissions from its coal plants, the traditional operating companies have begun construction of flue gas desulfurization projects and have entered into various long-term commitments for the procurement of limestone to be used in such equipment.

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2008.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) Southern Company forecasts postretirement trust contributions over a three-year period. Southern Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time. Therefore, no amounts related to the pension trust fund are included in the table. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from Southern Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

Southern Company's 2008 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning the strategic goals for the wholesale business, retail sales growth, customer growth, storm damage cost recovery and repairs, fuel cost recovery and other rate actions, environmental regulations and expenditures, earnings growth, dividend payout ratios, access to sources of capital, projections for postretirement benefit and nuclear decommissioning trust contributions, financing activities, completion of construction projects, plans and estimated costs for new generation resources, impacts of adoption of new accounting rules, unrecognized tax benefits related to leveraged lease transactions, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances, and also changes in tax and other laws and regulations to which Southern Company and its subsidiaries are subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including the pending EPA civil actions against certain Southern Company subsidiaries, FERC matters, IRS audits, and Mirant matters;
- the effects, extent, and timing of the entry of additional competition in the markets in which Southern Company's subsidiaries operate;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs;
- investment performance of Southern Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- regulatory approvals related to the potential Plant Vogtle expansion, including Georgia PSC and NRC approvals;
- the performance of projects undertaken by the non-utility businesses and the success of efforts to invest in and develop new opportunities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to Southern Company or its subsidiaries;
- the ability of counterparties of Southern Company and its subsidiaries to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with neighboring utilities and other wholesale customers;
- the direct or indirect effect on Southern Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including Southern Company's and its subsidiaries' credit ratings;
- the ability of Southern Company and its subsidiaries to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on Southern Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

Southern Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Southern Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006
		(in millions)	
Operating Revenues:			
Retail revenues	**$14,055**	$12,639	$11,801
Wholesale revenues	**2,400**	1,988	1,822
Other electric revenues	**545**	513	465
Other revenues	**127**	213	268
Total operating revenues	**17,127**	15,353	14,356
Operating Expenses:			
Fuel	**6,818**	5,856	5,152
Purchased power	**815**	515	543
Other operations and maintenance	**3,748**	3,670	3,519
Depreciation and amortization	**1,443**	1,245	1,200
Taxes other than income taxes	**797**	741	718
Total operating expenses	**13,621**	12,027	11,132
Operating Income	**3,506**	3,326	3,224
Other Income and (Expense):			
Allowance for equity funds used during construction	**152**	106	50
Interest income	**33**	45	41
Equity in income (losses) of unconsolidated subsidiaries	**11**	(24)	(57)
Leveraged lease (losses) income	**(85)**	40	69
Impairment loss on equity method investments	**-**	-	(16)
Interest expense, net of amounts capitalized	**(866)**	(886)	(866)
Preferred and preference dividends of subsidiaries	**(65)**	(48)	(34)
Other income (expense), net	**(29)**	10	(58)
Total other income and (expense)	**(849)**	(757)	(871)
Earnings Before Income Taxes	**2,657**	2,569	2,353
Income taxes	**915**	835	780
Consolidated Net Income	**$ 1,742**	$ 1,734	$ 1,573
Common Stock Data:			
Earnings per share–			
Basic	**$2.26**	$2.29	$2.12
Diluted	**2.25**	2.28	2.10
Average number of shares of common stock outstanding – (in millions)			
Basic	**771**	756	743
Diluted	**775**	761	748
Cash dividends paid per share of common stock	**$1.6625**	$1.595	$1.535

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2008, 2007, and 2006

Southern Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006
		(in millions)	
Operating Activities:			
Consolidated net income	**$ 1,742**	$ 1,734	$ 1,573
Adjustments to reconcile consolidated net income to net cash provided from operating activities --			
Depreciation and amortization	**1,704**	1,486	1,421
Deferred income taxes and investment tax credits	**215**	7	202
Deferred revenues	**120**	(2)	(1)
Allowance for equity funds used during construction	**(152)**	(106)	(50)
Equity in (income) losses of unconsolidated subsidiaries	**(11)**	24	57
Leveraged lease losses (income)	**85**	(40)	(69)
Pension, postretirement, and other employee benefits	**21**	39	46
Stock based compensation expense	**20**	28	28
Derivative fair value adjustments	**(1)**	(30)	32
Hedge settlements	**15**	10	13
Hurricane Katrina grant proceeds-property reserve	**-**	60	-
Other, net	**(97)**	60	51
Changes in certain current assets and liabilities --			
Receivables	**(176)**	165	(69)
Fossil fuel stock	**(303)**	(39)	(246)
Materials and supplies	**(23)**	(71)	7
Other current assets	**(36)**	-	73
Accounts payable	**(74)**	105	(173)
Hurricane Katrina grant proceeds	**-**	14	120
Accrued taxes	**293**	(19)	(103)
Accrued compensation	**36**	(40)	(24)
Other current liabilities	**20**	10	(68)
Net cash provided from operating activities	**3,398**	3,395	2,820
Investing Activities:			
Property additions	**(3,961)**	(3,545)	(2,994)
Investment in restricted cash from pollution control bonds	**(96)**	(157)	-
Distribution of restricted cash from pollution control bonds	**69**	78	-
Nuclear decommissioning trust fund purchases	**(720)**	(783)	(751)
Nuclear decommissioning trust fund sales	**712**	775	743
Proceeds from property sales	**34**	33	150
Hurricane Katrina capital grant proceeds	**7**	35	153
Investment in unconsolidated subsidiaries	**(1)**	(37)	(64)
Cost of removal net of salvage	**(123)**	(108)	(90)
Other	**(47)**	-	19
Net cash used for investing activities	**(4,126)**	(3,709)	(2,834)
Financing Activities:			
Increase (decrease) in notes payable, net	**(314)**	(669)	683
Proceeds --			
Long-term debt	**3,686**	3,826	1,564
Preferred and preference stock	**-**	470	150
Common stock	**474**	538	137
Redemptions --			
Long-term debt	**(1,469)**	(2,566)	(1,366)
Preferred and preference stock	**(125)**	-	(15)
Payment of common stock dividends	**(1,280)**	(1,205)	(1,140)
Other	**(28)**	(46)	(34)
Net cash provided from (used for) financing activities	**944**	348	(21)
Net Change in Cash and Cash Equivalents	**216**	34	(35)
Cash and Cash Equivalents at Beginning of Year	**201**	167	202
Cash and Cash Equivalents at End of Year	**$ 417**	$ 201	$ 167

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS

At December 31, 2008 and 2007

Southern Company and Subsidiary Companies 2008 Annual Report

Assets	2008	2007
	(in millions)	
Current Assets:		
Cash and cash equivalents	**$ 417**	$ 201
Restricted cash	**103**	68
Receivables --		
Customer accounts receivable	**1,054**	1,000
Unbilled revenues	**320**	294
Under recovered regulatory clause revenues	**646**	716
Other accounts and notes receivable	**301**	348
Accumulated provision for uncollectible accounts	**(26)**	(22)
Fossil fuel stock, at average cost	**1,018**	710
Materials and supplies, at average cost	**757**	725
Vacation pay	**140**	135
Prepaid expenses	**302**	146
Other	**326**	411
Total current assets	**5,358**	4,732
Property, Plant, and Equipment:		
In service	**50,618**	47,176
Less accumulated depreciation	**18,286**	17,413
	32,332	29,763
Nuclear fuel, at amortized cost	**510**	336
Construction work in progress	**3,036**	3,228
Total property, plant, and equipment	**35,878**	33,327
Other Property and Investments:		
Nuclear decommissioning trusts, at fair value	**864**	1,132
Leveraged leases	**897**	984
Other	**227**	238
Total other property and investments	**1,988**	2,354
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**973**	910
Prepaid pension costs	**-**	2,369
Unamortized debt issuance expense	**208**	191
Unamortized loss on reacquired debt	**271**	289
Deferred under recovered regulatory clause revenues	**606**	389
Other regulatory assets	**2,637**	768
Other	**428**	460
Total deferred charges and other assets	**5,123**	5,376
Total Assets	**$48,347**	$45,789

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS

At December 31, 2008 and 2007

Southern Company and Subsidiary Companies 2008 Annual Report

Liabilities and Stockholders' Equity	2008	2007
	(in millions)	
Current Liabilities:		
Securities due within one year	**$ 617**	$ 1,178
Notes payable	**953**	1,272
Accounts payable	**1,250**	1,214
Customer deposits	**302**	274
Accrued taxes --		
Income taxes	**197**	52
Unrecognized tax benefits	**131**	165
Other	**396**	330
Accrued interest	**196**	218
Accrued vacation pay	**179**	171
Accrued compensation	**447**	408
Liabilities from risk management activities	**261**	63
Other	**297**	286
Total current liabilities	**5,226**	5,631
Long-term Debt (See accompanying statements)	**16,816**	14,143
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**6,080**	5,839
Deferred credits related to income taxes	**259**	272
Accumulated deferred investment tax credits	**455**	479
Employee benefit obligations	**2,057**	1,492
Asset retirement obligations	**1,183**	1,200
Other cost of removal obligations	**1,321**	1,308
Other regulatory liabilities	**262**	1,613
Other	**330**	347
Total deferred credits and other liabilities	**11,947**	12,550
Total Liabilities	**33,989**	32,324
Preferred and Preference Stock of Subsidiaries (See accompanying statements)	**1,082**	1,080
Common Stockholders' Equity (See accompanying statements)	**13,276**	12,385
Total Liabilities and Stockholders' Equity	**$48,347**	$45,789
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31, 2008 and 2007

Southern Company and Subsidiary Companies 2008 Annual Report

		2008	2007	2008	2007
		(in millions)		*(percent of total)*	
Long-Term Debt:					
Long-term debt payable to affiliated trusts --					
Maturity	Interest Rates				
2042 through 2044	5.50% to 5.88%	**$ 412**	$ 412		
Long-term senior notes and debt --					
Maturity	Interest Rates				
2008	2.54% to 7.00%	**-**	459		
2009	4.10% to 7.00%	**128**	127		
2010	4.70%	**102**	102		
2011	4.00% to 5.57%	**303**	302		
2012	4.85% to 6.25%	**1,778**	1,478		
2013	4.35% to 6.00%	**936**	236		
2014 through 2048	4.88% to 8.20%	**8,437**	7,824		
Adjustable rates (at 1/1/09):					
2008	4.94% to 5.00%	**-**	550		
2009	2.3288% to 2.36%	**440**	440		
2010	2.42% to 6.10%	**1,034**	202		
2011	1.645% to 2.35%	**490**	-		
Total long-term senior notes and debt		**13,648**	11,720		
Other long-term debt --					
Pollution control revenue bonds --					
Maturity	Interest Rates				
2016 through 2048	1.95% to 6.00%	**2,030**	812		
Variable rates (at 1/1/09):					
2011 through 2041	0.80% to 3.00%	**1,257**	2,170		
Total other long-term debt		**3,287**	2,982		
Capitalized lease obligations		**106**	101		
Unamortized debt premium (discount), net		**(20)**	(19)		
Total long-term debt (annual interest requirement -- $ 858 million)		**17,433**	15,196		
Less amount due within one year		**617**	1,053		
Long-term debt excluding amount due within one year		**16,816**	14,143	**53.9%**	51.2%

CONSOLIDATED STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2008 and 2007
Southern Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2008	2007
	(in millions)		*(percent of total)*	
Preferred and Preference Stock of Subsidiaries:				
Cumulative preferred stock				
$100 par or stated value -- 4.20% to 5.44%				
Authorized - 20 million shares				
Outstanding - 1 million shares	**81**	81		
$1 par value -- 4.95% to 5.83%				
Authorized - 28 million shares				
Outstanding - 12 million shares: $25 stated value	**294**	294		
Outstanding - 2008: 0 shares	**-**	123		
Outstanding - 2007: 1,250 shares: $100,000 stated capital				
Non-cumulative preferred stock				
$25 par value -- 6.00% to 6.13%				
Authorized - 60 million shares				
Outstanding - 2 million shares	**45**	45		
Preference stock				
Authorized - 65 million shares				
Outstanding - $1 par value -- 5.63% to 6.50%	**343**	343		
- 14 million shares (non-cumulative)				
- $100 par or stated value -- 6.00% to 6.50%	**319**	319		
- 3 million shares (non-cumulative)				
Total preferred and preference stock of subsidiaries				
(annual dividend requirement -- $ 65 million)	**1,082**	1,205		
Less amount due within one year	**-**	125		
Preferred and preference stock of subsidiaries				
excluding amount due within one year	**1,082**	1,080	**3.5**	3.9
Common Stockholders' Equity:				
Common stock, par value $5 per share --	**3,888**	3,817		
Authorized - 1 billion shares				
Issued -- 2008: 778 million shares				
-- 2007: 764 million shares				
Treasury -- 2008: 0.4 million shares				
-- 2007: 0.4 million shares				
Paid-in capital	**1,893**	1,454		
Treasury, at cost	**(12)**	(11)		
Retained earnings	**7,612**	7,155		
Accumulated other comprehensive income (loss)	**(105)**	(30)		
Total common stockholders' equity	**13,276**	12,385	**42.6**	44.9
Total Capitalization	**$31,174**	$27,608	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

For the Years Ended December 31, 2008, 2007, and 2006

Southern Company and Subsidiary Companies 2008 Annual Report

	Common Stock				Accumulated	
	Par Value	Paid-In Capital	Treasury	Retained Earnings	Other Comprehensive Income (Loss)	Total
				(in millions)		
Balance at December 31, 2005	$3,759	$1,085	$ (359)	$6,332	$ (128)	$10,689
Net income	-	-	-	1,573	-	1,573
Other comprehensive income	-	-	-	-	19	19
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	-	52	52
Stock issued	-	11	168	-	-	179
Cash dividends	-	-	-	(1,140)	-	(1,140)
Other	-	-	(1)	-	-	(1)
Balance at December 31, 2006	3,759	1,096	(192)	6,765	(57)	11,371
Net income	-	-	-	1,734	-	1,734
Other comprehensive income	-	-	-	-	27	27
Stock issued	58	356	183	-	-	597
Adjustment to initially apply FIN 48, net of tax	-	-	-	(15)	-	(15)
Adjustment to initially apply FSP 13-2, net of tax	-	-	-	(125)	-	(125)
Cash dividends	-	-	-	(1,204)	-	(1,204)
Other	-	2	(2)	-	-	-
Balance at December 31, 2007	**3,817**	**1,454**	**(11)**	**7,155**	**(30)**	**12,385**
Net income	-	-	-	**1,742**	-	**1,742**
Other comprehensive loss	-	-	-	-	**(75)**	**(75)**
Stock issued	**71**	**438**	-	-	-	**509**
Cash dividends	-	-	-	**(1,279)**	-	**(1,279)**
Other	-	**1**	**(1)**	**(6)**	-	**(6)**
Balance at December 31, 2008	**$3,888**	**$1,893**	**$(12)**	**$7,612**	**$(105)**	**$13,276**

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Southern Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006
		(in millions)	
Consolidated Net Income	**$1,742**	$1,734	$1,573
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(19), $(3), and $(5), respectively	**(30)**	(5)	(8)
Reclassification adjustment for amounts included in net income, net of tax of $7, $6, and $-, respectively	**11**	9	1
Marketable securities:			
Changes in fair value, net of tax of $(4), $3, and $4, respectively	**(7)**	4	8
Reclassification adjustment for amounts included in net income, net of tax of $-, $-, and $-, respectively	-	(1)	-
Pension and other postretirement benefit plans:			
Benefit plan net gain (loss), net of tax of $(32), $13, and $-, respectively	**(51)**	20	-
Additional prior service costs from amendment to non-qualified pension plans, net of tax of $-, $(2), and $-, respectively	-	(2)	-
Change in additional minimum pension liability, net of tax of $-, $-, and $10, respectively	-	-	18
Reclassification adjustment for amounts included in net income, net of tax of $1, $1, and $-, respectively	**2**	2	-
Total other comprehensive income (loss)	**(75)**	27	19
Consolidated Comprehensive Income	**$1,667**	$1,761	$1,592

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

The Southern Company (the Company) is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power), are vertically integrated utilities providing electric service in four Southeastern states. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and the subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The financial statements reflect Southern Company's investments in the subsidiaries on a consolidated basis. The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary. All material intercompany transactions have been eliminated in consolidation.

The traditional operating companies, Southern Power, and certain of their subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC) and the traditional operating companies are also subject to regulation by their respective state public service commissions (PSC). The companies follow accounting principles generally accepted in the United States and comply with the accounting policies and practices prescribed by their respective commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Reclassifications

Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. The consolidated statements of income for the prior periods presented have been modified within the operating expenses section to combine the line items "Other operations" and "Maintenance" into a single line item entitled "Other operations and maintenance." The statements of cash flows for the prior periods presented were modified within the operating activities section to present a separate line item for "Deferred revenues" previously included in "Other, net." The consolidated balance sheet at December 31, 2007 has been modified within current liabilities to reflect the amount of "Unrecognized tax benefits" previously included within "Accrued taxes - Income taxes" and to present the amount of "Liabilities for risk management activities" previously included in "Other." These reclassifications had no effect on total assets, net income, cash flows, or earnings per share.

Related Party Transactions

Alabama Power and Georgia Power purchased synthetic fuel from Alabama Fuel Products, LLC (AFP), an entity in which Southern Holdings held a 30% ownership interest until July 2006, when its ownership interest was terminated. Total fuel purchases for January 2006 through June 2006 were $354 million. Synfuel Services, Inc. (SSI), another subsidiary of Southern Holdings, provided fuel transportation services to AFP that were ultimately reflected in the cost of the synthetic fuel billed to Alabama Power and Georgia Power. In connection with these services, the related revenues of approximately $62 million for January 2006 through June 2006, have been eliminated against fuel expense in the financial statements. SSI also provided additional services to AFP, as well as

to a related party of AFP. Revenues from these transactions totaled approximately $24 million for January 2006 through June 2006.

Subsequent to the termination of Southern Company's membership interest in AFP, Alabama Power and Georgia Power continued to purchase an additional $6 million, $750 million, and $384 million in fuel from AFP in 2008, 2007, and 2006, respectively. SSI continued to provide fuel transportation services of $131 million in 2007 and $62 million in 2006, which were eliminated against fuel expense in the financial statements. SSI also provided other additional services to AFP and a related party of AFP totaling $47 million and $21 million in 2007 and 2006, respectively. The synthetic fuel investments and related party transactions were terminated on December 31, 2007.

Regulatory Assets and Liabilities

The traditional operating companies are subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2008	2007	Note
		(in millions)	
Deferred income tax charges	$ 972	$ 911	(a)
Asset retirement obligations-asset	236	50	(a)
Asset retirement obligations-liability	(5)	(154)	(a)
Other cost of removal obligations	(1,321)	(1,308)	(a)
Deferred income tax credits	(260)	(275)	(a)
Loss on reacquired debt	271	289	(b)
Vacation pay	140	135	(c)
Under recovered regulatory clause revenues	432	371	(d)
Building lease	48	49	(d)
Generating plant outage costs	45	46	(d)
Under recovered storm damage costs	27	43	(d)
Property damage reserves	(97)	(90)	(d)
Fuel hedging (realized and unrealized) losses	314	25	(d)
Fuel hedging (realized and unrealized) gains	(10)	(20)	(d)
Other assets	164	88	(d)
Environmental remediation-asset	67	67	(d)
Environmental remediation-liability	(19)	(22)	(d)
Deferred purchased power	(156)	(20)	(d)
Other liabilities	(25)	(21)	(d)
Overfunded retiree benefit plans	-	(1,288)	(e)
Underfunded retiree benefit plans	2,068	547	(e)
Total assets (liabilities), net	$ 2,891	$ (577)	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue, which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year.

(d) Recorded and recovered or amortized as approved by the appropriate state PSCs.

(e) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

In the event that a portion of a traditional operating company's operations is no longer subject to the provisions of SFAS No. 71, such company would be required to write off or reclassify to accumulated other comprehensive income related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the traditional operating company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates. See Note 3 under "Alabama Power Retail Regulatory Matters," "Georgia Power Retail Regulatory Matters," "Gulf Power Retail Regulatory Matters," and "Storm Damage Cost Recovery" for additional information.

Revenues

Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Electric rates for the traditional operating companies include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors.

Retail fuel cost recovery mechanisms vary by each traditional operating company, but in general, the process requires periodic filings with the appropriate state PSC. Alabama Power continuously monitors the under/over recovered balance and files for a revised fuel rate when management deems appropriate. Georgia Power is required to file a new fuel case no later than March 1, 2009. On February 19, 2009, the Georgia PSC approved Georgia Power's request to delay the filing of that case until March 13, 2009. The new rates are expected to become effective on June 1, 2009. Gulf Power is required to notify the Florida PSC if the projected fuel cost over or under recovery exceeds 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. Mississippi Power is required to file for an adjustment to the fuel cost recovery factor annually. See Note 3 under "Alabama Power Retail Regulatory Matters," "Georgia Power Retail Regulatory Matters," and "Gulf Power Retail Regulatory Matters" for additional information.

Southern Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

Southern Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), Southern Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information on FIN 48.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction.

Southern Company's property, plant, and equipment consisted of the following at December 31:

	2008	2007
	(in millions)	
Generation	**$26,154**	$23,879
Transmission	**7,085**	6,761
Distribution	**13,856**	13,134
General	**2,750**	2,619
Plant acquisition adjustment	**43**	43
Utility plant in service	**49,888**	46,436
IT equipment and software	**240**	230
Communications equipment	**450**	452
Other	**40**	58
Other plant in service	**730**	740
Total plant in service	**$50,618**	$47,176

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific state PSC orders. Alabama Power accrues estimated nuclear refueling costs in advance of the unit's next refueling outage. Georgia Power defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles for Alabama Power and Georgia Power range from 18 to 24 months for each unit. In accordance with a Georgia PSC order, Georgia Power also defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2008, 3.0% in 2007, and 3.0% in 2006. Depreciation studies are conducted periodically to update the composite rates. These studies are filed with the respective state PSC for the traditional operating companies. Accumulated depreciation for utility plant in service totaled $17.9 billion and $17.0 billion at December 31, 2008 and 2007, respectively. When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under Georgia Power's retail rate plan for the three years ended December 31, 2007 (2004 Retail Rate Plan), Georgia Power was ordered to recognize Georgia PSC-certified capacity costs in rates evenly over the three years covered by the 2004 Retail Rate Plan. Georgia Power recorded credits to amortization of $19 million and $14 million in 2007 and 2006, respectively. See Note 3 under "Georgia Power Retail Regulatory Matters" for additional information.

In May 2004, the Mississippi PSC approved Mississippi Power's request to reclassify 266 megawatts of Plant Daniel units 3 and 4 capacity to jurisdictional cost of service effective January 1, 2004 and authorized Mississippi Power to include the related costs and revenue credits in jurisdictional rate base, cost of service, and revenue requirement calculations for purposes of retail rate recovery. Mississippi Power amortized the related regulatory liability pursuant to the Mississippi PSC's order as follows: $6 million in 2007 and $13 million in 2006, resulting in increases to earnings in each of those years.

Depreciation of the original cost of other plant in service is provided primarily on a straight-line basis over estimated useful lives ranging from 3 to 25 years. Accumulated depreciation for other plant in service totaled $433 million and $429 million at December 31, 2008 and 2007, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the various state PSCs allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facilities, Plants Farley, Hatch, and Vogtle. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2008 was $864 million. In addition, the Company has retirement obligations related to various landfill sites, underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the U.S. Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under FASB Statement No. 143 "Accounting for Asset Retirement Obligations" and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the various state PSCs, and are reflected in the balance sheets. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2008	2007
	(in millions)	
Balance beginning of year	**$1,203**	$1,137
Liabilities incurred	**4**	1
Liabilities settled	**(4)**	(8)
Accretion	**75**	74
Cash flow revisions	**(93)**	(1)
Balance end of year	**$1,185**	$1,203

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. Alabama Power and Georgia Power have external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to

nuclear decommissioning activities and the Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and state PSCs, as well as the Internal Revenue Service (IRS). The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as of December 31, 2008 as trading securities pursuant to FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115).

On January 1, 2008, the Company adopted FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Southern Company elected the fair value option only for investment securities held in the Funds. The Funds are included in the balance sheets at fair value, as disclosed in Note 10.

Management elected to continue to record the Funds at fair value because management believes that fair value best represents the nature of the Funds. Management has delegated day-to-day management of the investments in the Funds to unrelated third party managers with oversight by Southern Company, Alabama Power, and Georgia Power management. The managers of the Funds are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the investment return on the Funds' investments. Because of the Company's inability to choose to hold securities that have experienced unrealized losses until recovery of their value, all unrealized losses incurred during 2006 and 2007, prior to the adoption of SFAS No. 159, were considered other-than-temporary impairments under SFAS No. 115.

The adoption of SFAS No. 159 had no impact on the results of operations, cash flows, or financial condition of the Company. For all periods presented, all gains and losses, whether realized, unrealized, or identified as other-than-temporary, have been and will continue to be recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or other comprehensive income. Fair value adjustments, realized gains, and other-than-temporary impairment losses are determined on a specific identification basis.

At December 31, 2008, investment securities in the Funds totaled $862 million consisting of equity securities of $518 million, debt securities of $323 million, and $21 million of other securities. These amounts exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

At December 31, 2007, investment securities in the Funds totaled $1.1 billion consisting of equity securities of $788 million, debt securities of $312 million, and $32 million of other securities. Unrealized gains were $256 million for equity securities and $12 million for debt securities. Other-than-temporary impairments were $(28) million for equity securities and $(5) million for debt securities.

Sales of the securities held in the Funds resulted in cash proceeds of $712 million, $775 million, and $743 million, in 2008, 2007, and 2006, respectively, all of which were re-invested. For 2008, fair value reductions, including reinvested interest and dividends, was $(278) million, of which $(259) million related to securities held in the Funds at December 31, 2008. Realized gains and other-than-temporary impairment losses were $78 million and $(76) million, respectively, in 2007 and $40 million and $(30) million, respectively, in 2006. While the investment securities held in the Funds are reported as trading securities, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statement of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the respective state PSCs. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. Alabama Power and Georgia Power have filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC.

At December 31, 2008, the accumulated provisions for decommissioning were as follows:

	Plant Farley	Plant Hatch	Plant Vogtle
		(in millions)	
External trust funds	$404	$280	$168
Internal reserves	26	-	-
Total	$430	$280	$168

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning based on the most current studies, which were performed in 2008 for Plant Farley and in 2006 for the Georgia Power plants, were as follows for Alabama Power's Plant Farley and Georgia Power's ownership interests in Plants Hatch and Vogtle:

	Plant Farley	Plant Hatch	Plant Vogtle
Decommissioning periods:			
Beginning year	2037	2034	2027
Completion year	2065	2061	2051
		(in millions)	
Site study costs:			
Radiated structures	$1,060	$544	$507
Non-radiated structures	72	46	67
Total	$1,132	$590	$574

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, Alabama Power's decommissioning costs are based on the site study, and Georgia Power's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities as of 2006. The estimates used in current rates are $495 million and $334 million for Plants Hatch and Vogtle, respectively. Amounts expensed were $3 million in 2008 and $7 million annually for 2007 and 2006 for Plant Vogtle. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and 2.9% for Alabama Power and Georgia Power, respectively, and a trust earnings rate of 7.0% and 4.9% for Alabama Power and Georgia Power, respectively. As a result of license extensions, amounts previously contributed to the external trust funds for Plants Hatch and Farley are currently projected to be adequate to meet the decommissioning obligations. Georgia Power filed an application with the NRC in June 2007 to extend the licenses for Plant Vogtle Units 1 and 2 for an additional 20 years. Georgia Power anticipates the NRC may make a decision regarding the license extension for Plant Vogtle in 2009.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized

In accordance with regulatory treatment, the traditional operating companies record AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. The equity component of AFUDC is not included in calculating taxable income. Interest related to the construction of new facilities not included in the traditional operating companies' regulated rates is capitalized in accordance with standard interest capitalization requirements. AFUDC and interest capitalized, net of income taxes were 11.2%, 8.4%, and 4.2% of net income for 2008, 2007, and 2006, respectively.

Cash payments for interest totaled $787 million, $798 million, and $875 million in 2008, 2007, and 2006, respectively, net of amounts capitalized of $71 million, $64 million, and $27 million, respectively.

Impairment of Long-Lived Assets and Intangibles

Southern Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Reserves

Each traditional operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In accordance with their respective state PSC orders, the traditional operating companies accrued $40.4 million in 2008. Alabama Power, Gulf Power, and Mississippi Power also have discretionary authority from their state PSCs to accrue certain additional amounts as circumstances warrant. There were no material accruals for any year presented. See Note 3 under "Storm Damage Cost Recovery" for additional information regarding these reserves and the deferral of additional costs, as well as additional rate riders or other cost recovery mechanisms which have been approved by the respective state PSCs to recover the deferred costs and accrue reserves for future storms.

Leveraged Leases

Southern Company has several leveraged lease agreements, with terms ranging up to 45 years, which relate to international and domestic energy generation, distribution, and transportation assets. Southern Company receives federal income tax deductions for depreciation and amortization, as well as interest on long-term debt related to these investments. The Company reviews all important lease assumptions at least annually, or more frequently if events or changes in circumstances indicate that a change in assumptions has occurred or may occur. These assumptions include the effective tax rate, the residual value, the credit quality of the lessees, and the timing of expected tax cash flows.

Southern Company's net investment in domestic leveraged leases consists of the following at December 31:

	2008	2007
	(in millions)	
Net rentals receivable	**$492**	$494
Unearned income	**(230)**	(244)
Investment in leveraged leases	**262**	250
Deferred taxes from leveraged leases	**(189)**	(163)
Net investment in leveraged leases	**$ 73**	$ 87

A summary of the components of income from domestic leveraged leases was as follows:

	2008	2007	2006
		(in millions)	
Pretax leveraged lease income	**$14**	$16	$20
Income tax expense	**(6)**	(7)	(9)
Net leveraged lease income	**$ 8**	$ 9	$11

Southern Company's net investment in international leveraged leases consists of the following at December 31:

	2008	2007
	(in millions)	
Net rentals receivable	**$1,298**	$1,298
Unearned income	**(663)**	(563)
Investment in leveraged leases	**635**	735
Current taxes payable	**(120)**	-
Deferred taxes from leveraged leases	**(117)**	(316)
Net investment in leveraged leases	**$ 398**	$ 419

A summary of the components of income from international leveraged leases was as follows:

	2008	2007	2006
		(in millions)	
Pretax leveraged lease income (loss)	**$(99)**	$24	$ 49
Income tax benefit (expense)	**35**	(8)	(17)
Net leveraged lease income (loss)	**$(64)**	$16	$ 32

See Note 3 under "Income Tax Matters" for additional information regarding the leveraged lease transactions.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average costs of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the traditional operating companies through fuel cost recovery rates approved by each state PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

Southern Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (categorized in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of Southern Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the traditional operating companies' fuel hedging programs. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts, including derivatives related to synthetic fuel

investments, are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 6 under "Financial Instruments" for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. At December 31, 2008, the Company has recognized $8.5 million for the obligation to return cash collateral arising from derivative instruments, which is included in "Accounts payable" in the balance sheets.

Southern Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

The other Southern Company financial instruments for which the carrying amount did not equal fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2008	**$17,327**	**$17,114**
2007	$15,095	$14,931

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2). See Note 10 for all other items recognized at fair value in the financial statements.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, and certain changes in pension and other post retirement benefit plans, less income taxes and reclassifications for amounts included in net income.

Accumulated other comprehensive income (loss) balances, net of tax effects, were as follows:

	Qualifying Hedges	Marketable Securities	Pension and Other Postretirement Benefit Plans	Accumulated Other Comprehensive Income (Loss)
			(in millions)	
Balance at December 31, 2007	$(54)	$13	$ 11	$ (30)
Current period change	(19)	(7)	(49)	(75)
Balance at December 31, 2008	**$(73)**	**$ 6**	**$(38)**	**$(105)**

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. Southern Company has established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information. However, Southern Company and the traditional operating companies are not considered the primary beneficiaries of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are included in Long-term Debt in the balance sheets.

2. RETIREMENT BENEFITS

Southern Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2009. Southern Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, Southern Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The traditional operating companies fund related trusts to the extent required by their respective regulatory commissions. For the year ending December 31, 2009, postretirement trust contributions are expected to total approximately $56 million.

The measurement date for plan assets and obligations for 2008 was December 31 while the measurement date for prior years was September 30. Pursuant to FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), Southern Company was required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ended December 31, 2008. As permitted, Southern Company adopted the measurement date provisions of SFAS No. 158 effective January 1, 2008 resulting in an increase in long-term liabilities of approximately $28 million and an increase in prepaid pension costs of approximately $16 million.

Pension Plans

The total accumulated benefit obligation for the pension plans was $5.5 billion in 2008 and $5.3 billion in 2007. Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the projected benefit obligations and the fair value of plan assets were as follows:

	2008	2007
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$5,660**	$5,491
Service cost	**182**	147
Interest cost	**435**	324
Benefits paid	**(324)**	(241)
Plan amendments	**-**	50
Actuarial gain	**(74)**	(111)
Balance at end of year	**5,879**	5,660
Change in plan assets		
Fair value of plan assets at beginning of year	**7,624**	6,693
Actual return (loss) on plan assets	**(2,234)**	1,153
Employer contributions	**27**	19
Benefits paid	**(324)**	(241)
Fair value of plan assets at end of year	**5,093**	7,624
Funded status at end of year	**(786)**	1,964
Fourth quarter contributions	**-**	5
(Accrued liability) prepaid pension asset	**$ (786)**	$1,969

At December 31, 2008, the projected benefit obligations for the qualified and non-qualified pension plans were $5.5 billion and $0.4 billion, respectively. All pension plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's pension plan assets as of the end of year, along with the targeted mix of assets, is presented below:

	Target	2008	2007
Domestic equity	36%	34%	38%
International equity	24	23	24
Fixed income	15	14	15
Real estate	15	19	16
Private equity	10	10	7
Total	100%	100%	100%

Amounts recognized in the consolidated balance sheets related to the Company's pension plans consist of the following:

	2008	2007
	(in millions)	
Prepaid pension costs	$ -	$ 2,369
Other regulatory assets	1,579	188
Current liabilities, other	(23)	(21)
Other regulatory liabilities	-	(1,288)
Employee benefit obligations	(763)	(379)
Accumulated other comprehensive income	54	(26)

Presented below are the amounts included in accumulated other comprehensive income, regulatory assets, and regulatory liabilities at December 31, 2008 and 2007 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	Net(Gain)Loss
Balance at December 31, 2008:	*(in millions)*	
Accumulated other comprehensive income	$ 12	$ 42
Regulatory assets	220	1,359
Regulatory liabilities	-	-
Total	$232	$1,401
Balance at December 31, 2007:		
Accumulated other comprehensive income	$ 14	$ (40)
Regulatory assets	66	122
Regulatory liabilities	198	(1,486)
Total	$278	$(1,404)
Estimated amortization in net periodic pension cost in 2009:		
Accumulated other comprehensive income	$ 2	$-
Regulatory assets	33	7
Regulatory liabilities	-	-
Total	$35	$7

The components of other comprehensive income, along with the changes in the balances of regulatory assets and regulatory liabilities, related to the defined benefit pension plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Accumulated Other Comprehensive Income	Regulatory Assets	Regulatory Liabilities
		(in millions)	
Balance at December 31, 2006	$ -	$ 158	$ (507)
Net gain	(28)	-	(753)
Change in prior service costs	4	46	-
Reclassification adjustments:			
Amortization of prior service costs	(2)	(7)	(28)
Amortization of net gain	-	(9)	-
Total reclassification adjustments	(2)	(16)	(28)
Total change	(26)	30	(781)
Balance at December 31, 2007	(26)	188	(1,288)
Net loss	**83**	**1,412**	**1,322**
Change in prior service costs	**-**	**-**	**-**
Reclassification adjustments:			
Amortization of prior service costs	**(2)**	**(10)**	**(34)**
Amortization of net gain	**(1)**	**(11)**	**-**
Total reclassification adjustments	**(3)**	**(21)**	**(34)**
Total change	**80**	**1,391**	**1,288**
Balance at December 31, 2008	**$ 54**	**$1,579**	**$ -**

Components of net periodic pension cost were as follows:

	2008	2007	2006
		(in millions)	
Service cost	**$146**	$147	$ 153
Interest cost	**348**	324	300
Expected return on plan assets	**(525)**	(481)	(456)
Recognized net loss	**9**	10	16
Net amortization	**37**	35	26
Net periodic pension cost	**$ 15**	$ 35	$ 39

Net periodic pension cost is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2008, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2009	$ 289
2010	304
2011	322
2012	341
2013	362
2014 to 2018	2,187

Other Postretirement Benefits

Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the accumulated postretirement benefit obligations (APBO) and in the fair value of plan assets were as follows:

	2008	2007
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$1,797**	$1,830
Service cost	**36**	27
Interest cost	**138**	107
Benefits paid	**(108)**	(83)
Actuarial gain	**(139)**	(90)
Retiree drug subsidy	**9**	6
Balance at end of year	**1,733**	1,797
Change in plan assets		
Fair value of plan assets at beginning of year	**820**	731
Actual return (loss) on plan assets	**(232)**	105
Employer contributions	**142**	61
Benefits paid	**(99)**	(77)
Fair value of plan assets at end of year	**631**	820
Funded status at end of year	**(1,102)**	(977)
Fourth quarter contributions	**-**	65
Accrued liability	**$(1,102)**	$(912)

Other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of year, along with the targeted mix of assets, is presented below:

	Target	**2008**	2007
Domestic equity	44%	**34%**	45%
International equity	17	**18**	20
Fixed income	30	**38**	26
Real estate	5	**7**	6
Private equity	4	**3**	3
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of the following:

	2008	2007
	(in millions)	
Other regulatory assets	**$ 489**	$ 360
Current liabilities, other	**(3)**	(3)
Employee benefit obligations	**(1,099)**	(909)
Accumulated other comprehensive income	**8**	8

Presented below are the amounts included in accumulated other comprehensive income and regulatory assets at December 31, 2008 and 2007, related to the other postretirement benefit plans that had not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	Net(Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2008:			
Accumulated other comprehensive income	**$ 3**	**$ 5**	**$ -**
Regulatory assets	**88**	**335**	**66**
Total	**$91**	**$340**	**$66**
Balance at December 31, 2007:			
Accumulated other comprehensive income	$ 4	$ 4	$ -
Regulatory assets	99	177	84
Total	$103	$181	$84
Estimated amortization as net periodic postretirement benefit cost in 2009:			
Accumulated other comprehensive income	$ -	$ -	$ -
Regulatory assets	9	5	15
Total	$9	$5	$15

The components of other comprehensive income, along with the changes in the balance of regulatory assets, related to the other postretirement benefit plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Accumulated Other Comprehensive Income	Regulatory Assets
	(in millions)	
Balance at December 31, 2006	$14	$ 539
Net gain	(6)	(141)
Change in prior service costs	-	-
Reclassification adjustments:		
Amortization of transition obligation	-	(15)
Amortization of prior service costs	-	(9)
Amortization of net gain	-	(14)
Total reclassification adjustments	-	(38)
Total change	(6)	(179)
Balance at December 31, 2007	8	360
Net loss	**1**	**166**
Change in prior service costs	**-**	**-**
Reclassification adjustments:		
Amortization of transition obligation	**-**	**(18)**
Amortization of prior service costs	**(1)**	**(11)**
Amortization of net gain	**-**	**(8)**
Total reclassification adjustments	**(1)**	**(37)**
Total change	**-**	**129**
Balance at December 31, 2008	**$ 8**	**$ 489**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2008	2007	2006
		(in millions)	
Service cost	**$ 28**	$ 27	$ 30
Interest cost	**111**	107	98
Expected return on plan assets	**(59)**	(52)	(49)
Net amortization	**31**	38	43
Net postretirement cost	**$111**	$120	$122

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced Southern Company's expenses for the years ended December 31, 2008, 2007, and 2006 by approximately $35 million, $35 million, and $39 million, respectively.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the accumulated benefit obligation for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	**Subsidy Receipts**	**Total**
		(in millions)	
2009	$100	$ (8)	$ 92
2010	110	(10)	100
2011	120	(11)	109
2012	127	(13)	114
2013	134	(14)	120
2014 to 2018	746	(100)	646

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2005 for the 2006 plan year using a discount rate of 5.50%.

	2008	2007	2006
Discount	**6.75%**	6.30%	6.00%
Annual salary increase	**3.75**	3.75	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.15% for 2009, decreasing gradually to 5.50% through the year 2015 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2008 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in millions)	
Benefit obligation	$122	$126
Service and interest costs	9	7

Employee Savings Plan

Southern Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution up to 6% of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75% up to 6% of the employee's base salary. Total matching contributions made to the plan for 2008, 2007, and 2006 were $76 million, $73 million, and $62 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

Southern Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, Southern Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against Southern Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on Southern Company's financial statements.

Mirant Matters

Mirant Corporation (Mirant) was an energy company with businesses that included independent power projects and energy trading and risk management companies in the U.S. and selected other countries. It was a wholly-owned subsidiary of Southern Company until its initial public offering in October 2000. In April 2001, Southern Company completed a spin-off to its shareholders of its remaining ownership, and Mirant became an independent corporate entity.

Mirant Bankruptcy

In July 2003, Mirant and certain of its affiliates filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Northern District of Texas. The Bankruptcy Court entered an order confirming Mirant's plan of reorganization in December 2005, and Mirant announced that this plan became effective in January 2006. As part of the plan, Mirant transferred substantially all of its assets and its restructured debt to a new corporation that adopted the name Mirant Corporation (Reorganized Mirant).

Southern Company has certain contingent liabilities associated with guarantees of contractual commitments made by Mirant's subsidiaries discussed in Note 7 under "Guarantees" and with various lawsuits related to Mirant discussed below. Also, Southern Company has joint and several liability with Mirant regarding the joint consolidated federal income tax returns through 2001, as discussed in Note 5. In December 2004, as a result of concluding an IRS audit for the tax years 2000 and 2001, Southern Company paid approximately $39 million in additional tax and interest related to Mirant tax items and filed a claim in Mirant's bankruptcy case for that amount. Through December 2008, Southern Company received from the IRS approximately $38 million in refunds related to Mirant. Southern Company believes it has a right to recoup the $39 million tax payment owed by Mirant from such tax refunds. As a result, Southern Company intends to retain the tax refunds and reduce its claim against Mirant for the payment of Mirant taxes by the amount of such refunds. MC Asset Recovery, a special purpose subsidiary of Reorganized Mirant, has objected to and sought to equitably subordinate the Southern Company tax claim in its fraudulent

transfer litigation against Southern Company. Southern Company has reserved the remaining amount with respect to its Mirant tax claim.

Under the terms of the separation agreements entered into in connection with the spin-off, Mirant agreed to indemnify Southern Company for costs associated with these guarantees, lawsuits, and additional IRS assessments. However, as a result of Mirant's bankruptcy, Southern Company sought reimbursement as an unsecured creditor in Mirant's Chapter 11 proceeding. As part of a complaint filed against Southern Company in June 2005 and amended thereafter, Mirant and The Official Committee of Unsecured Creditors of Mirant Corporation (Unsecured Creditors' Committee) objected to and sought equitable subordination of Southern Company's claims, and Mirant moved to reject the separation agreements entered into in connection with the spin-off. MC Asset Recovery has been substituted as plaintiff in the complaint. If Southern Company's claims for indemnification with respect to these, or any additional future payments, are allowed, then Mirant's indemnity obligations to Southern Company would constitute unsecured claims against Mirant entitled to stock in Reorganized Mirant. The final outcome of this matter cannot now be determined.

MC Asset Recovery Litigation

In June 2005, Mirant, as a debtor in possession, and the Unsecured Creditors' Committee filed a complaint against Southern Company in the U.S. Bankruptcy Court for the Northern District of Texas, which was amended in July 2005, February 2006, May 2006, and March 2007.

In December 2005, the Bankruptcy Court entered an order authorizing the transfer of this proceeding, along with certain other actions, to MC Asset Recovery. Under that order, Reorganized Mirant is obligated to fund up to $20 million in professional fees in connection with the lawsuits, as well as certain additional amounts. Any net recoveries from these lawsuits will be distributed to, and shared equally by, certain unsecured creditors and the original equity holders. In January 2006, the U.S. District Court for the Northern District of Texas substituted MC Asset Recovery as plaintiff.

The complaint, as amended in March 2007, alleges that Southern Company caused Mirant to engage in certain fraudulent transfers and to pay illegal dividends to Southern Company prior to the spin-off. The alleged fraudulent transfers and illegal dividends include without limitation: (1) certain dividends from Mirant to Southern Company in the aggregate amount of $668 million, (2) the repayment of certain intercompany loans and accrued interest in an aggregate amount of $1.035 billion, and (3) the dividend distribution of one share of Series B Preferred Stock and its subsequent redemption in exchange for Mirant's 80% interest in a holding company that owned SE Finance Capital Corporation and Southern Company Capital Funding, Inc., which transfer plaintiff asserts is valued at over $200 million. The complaint also seeks to recharacterize certain advances from Southern Company to Mirant for investments in energy facilities from debt to equity. The complaint further alleges that Southern Company is liable to Mirant's creditors for the full amount of Mirant's liability under an alter ego theory of recovery and that Southern Company breached its fiduciary duties to Mirant and its creditors, caused Mirant to breach its fiduciary duties to creditors, and aided and abetted breaches of fiduciary duties by Mirant's directors and officers. The complaint also seeks recoveries under the theories of restitution and unjust enrichment. In addition, the complaint alleged a claim under the Federal Debt Collection Procedure Act (FDCPA) to avoid certain transfers from Mirant to Southern Company; however, on July 7, 2008, the court ruled that the FDCPA does not apply and that Georgia law should apply instead. The complaint seeks monetary damages in excess of $2 billion plus interest, punitive damages, attorneys' fees, and costs. Finally, the complaint includes an objection to Southern Company's pending claims against Mirant in the Bankruptcy Court (which relate to reimbursement under the separation agreements of payments such as income taxes, interest, legal fees, and other guarantees described in Note 7) and seeks equitable subordination of Southern Company's claims to the claims of all other creditors. Southern Company served an answer to the complaint in April 2007.

In January 2006, the U.S. District Court for the Northern District of Texas granted Southern Company's motion to withdraw this action from the Bankruptcy Court and, in February 2006, granted Southern Company's motion to transfer the case to the U.S. District Court for the Northern District of Georgia. In May 2006, Southern Company filed a motion for summary judgment seeking entry of judgment against the plaintiff as to all counts of the complaint. In December 2006, the U.S. District Court for the Northern District of Georgia granted in part and denied in part the motion. As a result, certain breach of fiduciary duty claims alleged in earlier versions of the complaint are barred; all other claims in the complaint were allowed to proceed. On August 6, 2008, Southern Company filed a second motion for summary judgment. MC Asset Recovery filed its response to Southern Company's motion for summary judgment on October 20, 2008. On February 5, 2009, the court denied the summary judgment motion in connection with the fraudulent conveyance and illegal dividend claims concerning certain advance return/loan repayments in 1999, dividends in 1999 and 2000, and transfers in connection with Mirant's separation from Southern Company. The court granted Southern Company's motion for summary judgment with respect to certain claims, including claims for restitution and unjust enrichment, claims that Southern Company aided and abetted Mirant's directors' breach of fiduciary duties to Mirant, and claims that Southern Company used Mirant as an alter ego. In addition, the court granted Southern Company's motion in connection with the fraudulent transfer and illegal dividend claims concerning certain turbine termination payments. Southern Company believes there is no meritorious basis for the claims in the complaint and is vigorously defending itself in this action. However, the final outcome of this matter cannot now be determined.

Mirant Securities Litigation

In November 2002, Southern Company, certain former and current senior officers of Southern Company, and 12 underwriters of Mirant's initial public offering were added as defendants in a class action lawsuit that several Mirant shareholders originally filed against Mirant and certain Mirant officers in May 2002. Several other similar lawsuits filed subsequently were consolidated into this litigation in the U.S. District Court for the Northern District of Georgia. The amended complaint is based on allegations related to alleged improper energy trading and marketing activities involving the California energy market, alleged false statements and omissions in Mirant's prospectus for its initial public offering and in subsequent public statements by Mirant, and accounting-related issues previously disclosed by Mirant. The lawsuit purports to include persons who acquired Mirant securities between September 26, 2000 and September 5, 2002.

In July 2003, the court dismissed all claims based on Mirant's alleged improper energy trading and marketing activities involving the California energy market. The other claims do not allege any improper trading and marketing activity, accounting errors, or material misstatements or omissions on the part of Southern Company but seek to impose liability on Southern Company based on allegations that Southern Company was a "control person" as to Mirant prior to the spin-off date. Southern Company filed an answer to the consolidated amended class action complaint in September 2003. Plaintiffs also filed a motion for class certification.

During Mirant's Chapter 11 proceeding, the securities litigation was stayed, with the exception of limited discovery. Since Mirant's plan of reorganization has become effective, the stay has been lifted. In March 2006, the plaintiffs filed a motion for reconsideration requesting that the court vacate that portion of its July 2003 order dismissing the plaintiffs' claims based upon Mirant's alleged improper energy trading and marketing activities involving the California energy market. Southern Company and the other defendants opposed the plaintiffs' motion. In March 2007, the court granted plaintiffs' motion for reconsideration, reinstated the California energy market claims, and granted in part and denied in part defendants' motion to compel certain class certification discovery. In March 2007, defendants filed renewed motions to dismiss the California energy claims on grounds originally set forth in their 2003 motions to dismiss, but which were not addressed by the court. In July 2007, certain defendants, including Southern Company, filed motions for reconsideration of the court's denial of a motion seeking dismissal of certain federal securities laws claims based upon, among other things, certain alleged errors included in financial statements issued by Mirant. On August 6, 2008, the court entered an order in regard to the defendants' motions to

dismiss and for partial summary judgment. The court granted the defendants' motion for partial summary judgment in two respects concluding that certain holders of Mirant stock do not have standing under the securities laws. The court denied the defendants' other motions and granted leave to the plaintiffs to re-plead their claims against the defendants. In accordance with the court's order, the plaintiffs filed an amended complaint. The plaintiffs added allegations based upon claims asserted against Southern Company in the MC Asset Recovery litigation. Southern Company and the remaining defendants filed motions to dismiss the amended complaint on October 9, 2008. On January 7, 2009, the trial judge dismissed all counts of the plaintiffs' second amended complaint with prejudice. This matter is now concluded.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama after Alabama Power was dismissed from the original action. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power. The civil actions request penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units. The action against Georgia Power has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case, and the ultimate outcome of these matters cannot be determined at this time.

Southern Company believes that the traditional operating companies complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in either of these cases could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

Southern Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the subsidiaries may also incur substantial costs to clean up properties. The traditional operating companies have each received authority from their respective state PSCs to recover approved environmental compliance costs through regulatory mechanisms. Within limits approved by the state PSCs, these rates are adjusted annually or as necessary.

Georgia Power's environmental remediation liability as of December 31, 2008 was $10.1 million. Georgia Power has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and CERCLA NPL are anticipated.

By letter dated September 30, 2008, the EPA advised Georgia Power that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices from the EPA. Georgia Power, along with other named PRPs, will participate in negotiations with the EPA

to address cleanup of the site and reimbursement for the EPA's past expenditures related to work performed at the site. The ultimate outcome of this matter will depend upon further environmental assessment and the ultimate number of PRPs and cannot be determined at this time; however, it is not expected to have a material impact on Southern Company's financial statements.

Gulf Power's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $66.8 million as of December 31, 2008. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at Gulf Power substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through Gulf Power's environmental cost recovery clause; therefore, there was no impact on net income as a result of these estimates.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

FERC Matters

Market-Based Rate Authority

Each of the traditional operating companies and Southern Power has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by any subsidiary of Southern Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the traditional operating companies and Southern Power to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $19.7 million, plus interest. Southern Company and its subsidiaries believe that there is no meritorious basis for an adverse decision in this proceeding and are vigorously defending themselves in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability

obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Intercompany Interchange Contract

The Company's generation fleet in its retail service territory is operated under the Intercompany Interchange Contract (IIC), as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the traditional operating companies, Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms and Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan did not have a material impact on the Company's financial statements. In November 2007, Southern Company notified the FERC that the plan had been implemented. On December 12, 2008, the FERC division of audits issued for public comment its final audit report pertaining to compliance implementation and related matters. No comments challenging the audit report's findings were submitted. A decision is now pending from the FERC.

Generation Interconnection Agreements

In November 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, filed complaints at the FERC requesting that the FERC modify the agreements and that those Southern Company subsidiaries refund a total of $19 million previously paid for interconnection facilities. No other similar complaints are pending with the FERC.

In January 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order required the modification of Tenaska's interconnection agreements, under the provisions of the order, Southern Company determined that no refund was payable to Tenaska. Southern Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of FERC's methodology for determining the amount of refunds. The requested rehearings were denied, and Southern Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Telecom, Inc. (a subsidiary of SouthernLINC Wireless), have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment and seek compensatory and punitive damages and injunctive relief. Management of Southern Company and its subsidiaries believe that they have complied with applicable laws and that the plaintiffs' claims are without merit.

To date, Mississippi Power has entered into agreements with plaintiffs in approximately 95% of the actions pending against Mississippi Power to clarify its easement rights in the State of Mississippi. These agreements have been approved by the Circuit Courts of Harrison County and Jasper County, Mississippi (First Judicial Circuit), and dismissals of the related cases are in progress. These agreements have not resulted in any material effects on Southern Company's financial statements.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Telecom, Inc. (a subsidiary of SouthernLINC Wireless), were named as defendants in a lawsuit brought in Troup County, Georgia, Superior Court by Interstate Fiber Network, a subsidiary of telecommunications company ITC DeltaCom, Inc. that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Income Tax Matters

Leveraged Leases

In 2002, the IRS began the examination of three sale-in-lease-out (SILO) transactions entered into by Southern Company. As a result of this examination, the IRS challenged the deductions related to these transactions. Southern disagreed with the IRS's conclusion, went through all administrative appeals, paid approximately $168 million of the additional tax, and sued the IRS for the refund of such taxes.

During the second quarter 2008, decisions in favor of the IRS were reached in several court cases involving other taxpayers with similar leveraged lease investments. Pursuant to the application of FIN 48 and FASB Staff Position No. FAS 13-2, "Accounting for a Change or Projected Change in the Timing of Cash Flows Relating to Income Taxes Generated by a Leveraged Lease Transaction," management is required to assess on a periodic basis, the likely outcome of the uncertain tax positions related to the SILO transactions. Based on these accounting standards and management's review of the recent court decisions, Southern Company recorded an after-tax charge of approximately $67 million in the second quarter 2008.

On December 12, 2008, Southern Company received from the Commissioner of the IRS an invitation to participate in a global settlement initiative related to the SILO transactions. Southern Company accepted the settlement offer on January 8, 2009. Pursuant to the settlement offer, Southern Company recorded an additional after-tax charge in the fourth quarter 2008 of $16 million. Including charges recorded in the second quarter 2008, total after-tax

charges related to settling the SILO litigation amounted to $83 million in 2008. Of the total, approximately $7 million represents interest and $76 million represents non-cash charges related to the reallocation of lease income and will be recognized in income over the remaining term of the affected leases. A final closing agreement with the IRS is expected to be completed in the first quarter 2009. At that time, Southern Company will make a cash payment to the IRS of approximately $113 million. This payment will represent $120 million related to the timing of tax benefits recognized in prior year tax returns, partially offset by $7 million in interest refunds. The settlement of the SILO issue represented a significant non-cash operating transaction due to the deposits previously paid to the IRS. This resulted in a reduction to other current assets of approximately $207 million, a reduction of approximately $168 million in accrued taxes, and a reduction of approximately $39 million in other current liabilities.

Georgia State Income Tax Credits

Georgia Power's 2005 through 2008 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. Georgia Power has also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue has not responded to these claims. In July 2007, Georgia Power filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. An unrecognized tax benefit has been recorded related to these credits. See Note 5 under "Unrecognized Tax Benefits" for additional information. If Georgia Power prevails, these claims could have a significant, and possibly material, positive effect on Southern Company's net income. If Georgia Power is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on Southern Company's cash flow. The ultimate outcome of this matter cannot now be determined.

Alabama Power Retail Regulatory Matters

Alabama Power operates under a Rate Stabilization and Equalization Plan (Rate RSE) approved by the Alabama PSC. Prior to 2007, Rate RSE provided for periodic annual adjustments based upon Alabama Power's earned return on end-of-period retail common equity. Effective January 2007 and thereafter, Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4% per year and any annual adjustment is limited to 5%. Prior to January 2007, annual adjustments were limited to 3.0%. Retail rates remain unchanged when the retail return on common equity (ROE) is projected to be between 13% and 14.5%. If Alabama Power's actual retail ROE is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail ROE fall below the allowed equity return range. The Rate RSE increase for 2008 was 3.24%, or $147 million annually and was effective in January 2008. On October 7, 2008, the Alabama PSC approved a corrective rate package primarily providing for adjustments associated with customer charges to certain existing rate structures. This package, effective in January 2009, is expected to generate additional annual revenues of approximately $168 million. Alabama Power expects these additional revenues will preclude the need for a rate adjustment under the Rate RSE in 2009 and agreed to a moratorium on any increase in 2009 under Rate RSE. On December 1, 2008, Alabama Power made its submission of projected data for calendar year 2009. The ratemaking procedures will remain in effect until the Alabama PSC votes to modify or discontinue them.

The Alabama PSC has also approved a rate mechanism that provides for adjustments to recognize the cost of placing new generating facilities in retail service and for the recovery of retail costs associated with certificated purchased power agreements (Rate CNP). The annual true-up adjustment effective in April 2006 increased retail rates by 0.5%, or $19 million annually. In April 2007, there was no adjustment to Rate CNP.

Rate CNP also allows for the recovery of Alabama Power's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism, based on forward-looking information, began operation in January 2005 and provides for the recovery of these costs pursuant to a factor that will be calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased due to environmental costs approximately 1.2% in January 2006, 0.6% in January 2007, and 2.4% in January 2008. On October 7, 2008, Alabama Power agreed to defer any increase in rates during 2009 under the portion of Rate CNP which permits recovery of costs associated with environmental laws and regulations until 2010. The deferral of the retail rate adjustments will have no significant effect on Southern Company's revenues or net income, but will have an immaterial impact on annual cash flows. On December 1, 2008, Alabama Power made its submission of projected data for calendar year 2009.

Alabama Power fuel costs are recovered under Rate ECR (Energy Cost Recovery), which provides for the addition of a fuel and energy cost factor to base rates. In June 2007, the Alabama PSC approved Alabama Power's request to increase the retail energy cost recovery rate to 3.100 cents per kilowatt hour (KWH), effective with billings beginning July 2007 for the 30-month period ending December 2009. On October 7, 2008, the Alabama PSC approved an increase in Alabama Power's Rate ECR factor to 3.983 cents per KWH for a 24-month period beginning with October 9, 2008 billings. Thereafter, the Rate ECR factor shall be 5.910 cents per KWH, absent a contrary order by the Alabama PSC. During the 24-month period, Alabama Power will be allowed to continue to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation. In the event the application of this increased Rate ECR factor results in an over recovered position during this period, Alabama Power will pay interest on any such over recovered balance at the same rate used to derive the carrying cost. Accordingly, this approved increase in the billing factor will have no significant effect on Southern Company's revenues or net income, but will increase annual cash flow. As of December 31, 2008, Alabama Power had an under recovered fuel balance of approximately $306 million, of which approximately $181 million is included in deferred charges and other assets in the balance sheets.

Georgia Power Retail Regulatory Matters

In December 2007, the Georgia PSC approved the 2007 Retail Rate Plan. Under the 2007 Retail Rate Plan, Georgia Power's earnings will continue to be evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be applied to rate refunds with the remaining one-third applied to an environmental compliance cost recovery (ECCR) tariff. There were no refunds related to earnings for the year 2008. Georgia Power has agreed that it will not file for a general base rate increase during this period unless its projected retail ROE falls below 10.25%. Retail base rates increased by approximately $99.7 million effective January 1, 2008 to provide for cost recovery of transmission, distribution, generation, and other investments, as well as increased operating costs. In addition, the ECCR tariff was implemented to allow for the recovery of costs for required environmental projects mandated by state and federal regulations. The ECCR tariff increased rates by approximately $222 million effective January 1, 2008. Georgia Power is required to file a general rate case by July 1, 2010, in response to which the Georgia PSC would be expected to determine whether the 2007 Retail Rate Plan should be continued, modified, or discontinued.

In December 2004, the Georgia PSC approved the retail rate plan for the years 2005 through 2007 (2004 Retail Rate Plan) for Georgia Power. Under the terms of the 2004 Retail Rate Plan, Georgia Power's earnings were evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% were applied to rate refunds, with the remaining one-third retained by Georgia Power. Retail rates and customer fees increased by approximately $203 million effective January 1, 2005 to cover the higher costs of purchased power, operating and maintenance expenses, environmental compliance, and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2007, Georgia Power refunded 2005 earnings above 12.25% retail ROE. There were no refunds related to earnings for 2006 or 2007.

Georgia Power has established fuel cost recovery rates approved by the Georgia PSC. The Georgia PSC approved increases in Georgia Power's total annual billings of approximately $383 million effective March 2007 and approximately $222 million effective June 1, 2008. The Georgia PSC order also requires Georgia Power to file for a new fuel cost recovery rate no later than March 1, 2009. On February 19, 2009, the Georgia PSC approved Georgia Power's request to delay the filing of that case until March 13, 2009. The new rates are expected to become effective on June 1, 2009. As of December 31, 2008, Georgia Power had an under recovered fuel balance of approximately $764 million, of which approximately $426 million is included in deferred charges and other assets in the balance sheets.

Gulf Power Retail Regulatory Matters

On July 29, 2008, the Florida PSC approved Gulf Power's request to increase the fuel cost recovery factor effective with billings beginning September 2008. The remaining portion of the projected under recovered balance is expected to be recovered in 2009. On September 2, 2008, Gulf Power filed its 2009 projected fuel cost recovery filing with the Florida PSC which includes the fuel factors proposed for January 2009 through December 2009. On October 13, 2008, Gulf Power notified the Florida PSC that the updated projected fuel cost under recovery balance at year-end exceeds the 10% threshold, but no adjustment to the fuel factor was requested. On November 6, 2008, the Florida PSC approved an increase of approximately 12.9% in the fuel factor for retail customers effective with billings beginning January 2009. The fuel factors are intended to allow Gulf Power to recover its projected 2009 fuel and purchased power costs as well as the 2008 under recovered amounts in 2009. Fuel cost recovery revenues, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changing the billing factor has no significant effect on Southern Company's revenues or net income, but does impact annual cash flow. As of December 31, 2008, Gulf Power had an under recovered fuel balance of approximately $97 million, which is included in current assets in the balance sheets.

Storm Damage Cost Recovery

Each traditional operating company maintains a reserve to cover the cost of damages from major storms to its transmission and distribution lines and generally the cost of uninsured damages to its generation facilities and other property. In addition, each traditional operating company affected by recent hurricanes has been authorized by its state PSC to defer the portion of the hurricane restoration costs that exceeded the balance in its storm damage reserve account. As of December 31, 2008, the under recovered balance in Southern Company's storm damage reserve accounts totaled approximately $27 million, of which approximately $21 million and $6 million, respectively, are included in the balance sheets herein under "Other Current Assets" and "Other Regulatory Assets."

In August 2005, Hurricane Katrina hit the Gulf Coast of the United States and caused significant damage within Mississippi Power's service area. The estimated total storm restoration costs relating to Hurricane Katrina through December 31, 2007 of $302.4 million, which was net of expected insurance proceeds of approximately $77 million, without offset for the property damage reserve of $3.0 million, was affirmed by the Mississippi PSC in June 2006, and Mississippi Power was ordered to establish a regulatory asset for the retail portion. The Mississippi PSC issued an order directing Mississippi Power to file an application with the Mississippi Development Authority (MDA) for a Community Development Block Grant (CDBG). In October 2006, Mississippi Power received from the MDA a CDBG in the amount of $276.4 million, which was allocated to both the retail and wholesale jurisdictions. In the same month, the Mississippi PSC issued a financing order that authorized the issuance of system restoration bonds for the remaining $25.2 million of the retail portion of storm recovery costs not covered by the CDBG. These funds were received in June 2007. Mississippi Power affirmed the $302.4 million total storm costs incurred as of December 31, 2007. Mississippi Power plans to file with the Mississippi PSC its final accounting of the restoration cost relating to Hurricane Katrina and the storm operations center by the end of the first quarter 2009, at which time the final net retail receivable of approximately $3.2 million is expected to be recovered.

In July 2006, the Florida PSC issued its order approving a stipulation and settlement between Gulf Power and several consumer groups that resolved all matters relating to Gulf Power's request for recovery of incurred costs for storm-recovery activities and the replenishment of Gulf Power's property damage reserve. The order provided for an extension of the storm-recovery surcharge then being collected by Gulf Power for an additional 27 months, expiring in June 2009. Funds collected by Gulf Power related to the storm recovery costs associated with previous hurricanes had been fully recovered by August 31, 2008. Funds collected by Gulf Power through its storm recovery surcharge are now being credited to the property damage reserve and will continue though June 2009 when the approved surcharge ends. The Florida PSC-approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $25.1 million and $36.0 million. The Florida PSC also authorized Gulf Power to make additional accruals above the $3.5 million at Gulf Power's discretion. Gulf Power accrued total expenses of $3.5 million in 2008, $3.5 million in 2007, and $6.5 million in 2006. According to the order, in the case of future storms, if Gulf Power incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, Gulf Power will be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80% of the claimed costs for storm-recovery activities. Gulf Power would then petition the Florida PSC for full recovery through an additional surcharge or other cost recovery mechanism. As of December 31, 2008, Gulf Power's balance in the property damage reserve totaled approximately $9.8 million which is included in the balance sheets under deferred liabilities.

Integrated Coal Gasification Combined Cycle

On January 16, 2009, Mississippi Power filed for a Certificate of Public Convenience and Necessity with the Mississippi PSC to allow construction of a new electric generating plant located in Kemper County, Mississippi. The plant would utilize an advanced integrated coal gasification combined cycle (IGCC) with an output capacity of 582 megawatts. The Kemper IGCC will use locally mined lignite (an abundant, lower heating value coal) from a proposed mine adjacent to the plant as fuel. This certificate, if approved by the Mississippi PSC, would authorize Mississippi Power to acquire, construct and operate the Kemper IGCC and related facilities. The Kemper IGCC, subject to federal and state environmental reviews and certain regulatory approvals, is expected to begin commercial operation in November 2013. As part of its filing, Mississippi Power has requested certain rate recovery treatment in accordance with the base load construction legislation.

Mississippi Power filed an application in June 2006 with the U.S. Department of Energy (DOE) for certain tax credits available to projects using clean coal technologies under the Energy Policy Act of 2005. The DOE subsequently certified the Kemper IGCC, and in November 2006 the IRS allocated Internal Revenue Code Section 48A tax credits of $133 million to Mississippi Power. The utilization of these credits is dependent upon meeting the certification requirements for the Kemper IGCC, including an in-service date no later than November 2013. Mississippi Power has secured all environmental reviews and permits necessary to commence construction of the Kemper IGCC and has entered into a binding contract for the steam turbine generator, completing two milestone requirements for the Section 48A credits.

On February 14, 2008, Mississippi Power also requested that the DOE transfer the remaining funds previously granted to a cancelled Southern Company project that would have been located in Orlando, Florida. On December 12, 2008, an agreement was reached to assign the remaining funds to the Kemper IGCC. The estimated construction cost of the Kemper IGCC is approximately $2.2 billion, which is net of $220 million related to funding to be received from the DOE related to project construction. The remaining DOE funding of $50 million is projected to be used for demonstration over the first few years of operation.

Beginning in December 2006, the Mississippi PSC has approved Mississippi Power's requested accounting treatment to defer the costs associated with Mississippi Power's generation resource planning, evaluation, and screening activities as a regulatory asset. On December 22, 2008, Mississippi Power requested an amendment to its original order that would allow these costs to continue to be charged to and remain in a regulatory asset until January 1, 2010. In its application, Mississippi Power reported that it anticipated spending approximately $61

million by or before May 31, 2009. At December 31, 2008, Mississippi Power had spent $42.3 million of the $61 million, of which $3.7 million related to land purchases capitalized. Of the remaining amount, $0.8 million was expensed and $37.8 million was deferred in other regulatory assets.

The final outcome of this matter cannot now be determined.

Nuclear

In August 2006, Southern Nuclear, on behalf of Georgia Power, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG Power), and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light and Sinking Fund Commissioners (collectively, Owners), filed an application with the Nuclear Regulatory Commission (NRC) for an early site permit relating to two additional nuclear units on the site of Plant Vogtle. See Note 4 to the financial statements for additional information on these co-owners. On March 31, 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units.

On April 8, 2008, Georgia Power, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners will pay a purchase price that will be subject to certain price escalation and adjustments, adjustments for change orders, and performance bonuses. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. Georgia Power's proportionate share, based on its current ownership interest, is 45.7%. Under the terms of a separate joint development agreement, the Owners finalized their ownership percentages on July 2, 2008, except for allowed changes, under certain limited circumstances, during the Georgia PSC certification process.

On August 1, 2008, Georgia Power submitted an application for the Georgia PSC to certify the project. Hearings began November 3, 2008 and a final certification decision is expected in March 2009.

If certified by the Georgia PSC and licensed by the NRC, Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively. The total plant value to be placed in service will also include financing costs for each of the Owners, the impacts of inflation on costs, and transmission and other costs that are the responsibility of the Owners. Georgia Power's proportionate share of the estimated in-service costs, based on its current ownership interest, is approximately $6.4 billion, subject to adjustments and performance bonuses under the Vogtle 3 and 4 Agreement.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Owners and the Consortium also have agreed to certain bonuses payable to the Consortium for early completion and unit performance. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

The obligations of Westinghouse Electric Company LLC and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Vogtle 3 and 4 Agreement is subject to certification by the Georgia PSC. In addition, the Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

Southern Company also is participating in NuStart Energy Development, LLC (NuStart Energy), a broad-based nuclear industry consortium formed to share the cost of developing a COL and the related NRC review. NuStart Energy was organized to complete detailed engineering design work and to prepare COL applications for two advanced reactor designs. COLs for the two reactor designs were submitted to the NRC during the fourth quarter of 2007. The COLs ultimately are expected to be transferred to one or more of the consortium companies; however, at this time, none of them have committed to build a new nuclear plant.

Southern Company is also exploring other possibilities relating to additional nuclear power projects, both on its own or in partnership with other utilities. The final outcome of these matters cannot now be determined.

Nuclear Fuel Disposal Costs

Alabama Power and Georgia Power have contracts with the United States, acting through the DOE, which provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and Alabama Power and Georgia Power are pursuing legal remedies against the government for breach of contract.

In July 2007, the U.S. Court of Federal Claims awarded Georgia Power approximately $30 million, based on its ownership interests, and awarded Alabama Power approximately $17 million, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plants Farley, Hatch, and Vogtle from 1998 through 2004. In July 2007, the government filed a motion for reconsideration, which was denied in November 2007. On January 2, 2008, the government filed an appeal, and on February 29, 2008, filed a motion to stay the appeal. On April 1, 2008, the court granted the government's motion to stay the appeal pending the court's decisions in three other similar cases already on appeal. Those cases were decided in August 2008. Based on the rulings in those cases, the appeal is expected to proceed in first quarter 2009.

On April 3, 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. On October 31, 2008, the court denied a similar request by the government to stay this proceeding. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2008 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on net income is expected as any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Expanded wet storage capacity and construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plants Hatch and Farley, on-site dry storage facilities are operational and can be expanded to accommodate spent fuel through the expected life of each plant.

4. JOINT OWNERSHIP AGREEMENTS

Alabama Power owns an undivided interest in units 1 and 2 of Plant Miller and related facilities jointly with Power South Energy Cooperative, Inc. Georgia Power owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with OPC, MEAG Power, the City of Dalton, Georgia, Florida Power & Light Company, and Jacksonville Electric Authority. In addition, Georgia Power has joint ownership agreements with OPC for the Rocky Mountain facilities and with Florida Power Corporation for a combustion turbine unit at Intercession City, Florida. Southern Power owns an undivided interest in Plant Stanton Unit A and related facilities jointly with the Orlando Utilities Commission, Kissimmee Utility Authority, and Florida Municipal Power Agency.

At December 31, 2008, Alabama Power's, Georgia Power's, and Southern Power's ownership and investment (exclusive of nuclear fuel) in jointly owned facilities with the above entities were as follows:

	Percent Ownership	Amount of Investment	Accumulated Depreciation
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$3,303	$1,918
Plant Hatch (nuclear)	50.1	953	521
Plant Miller (coal)			
Units 1 and 2	91.8	986	425
Plant Scherer (coal)			
Units 1 and 2	8.4	117	68
Plant Wansley (coal)	53.5	552	189
Rocky Mountain (pumped storage)	25.4	175	102
Intercession City (combustion turbine)	33.3	12	3
Plant Stanton (combined cycle)			
Unit A	65.0	151	14

At December 31, 2008, the portion of total construction work in progress related to Plants Miller, Scherer, and Wansley was $174 million, $247 million, and $114 million, respectively, primarily for environmental projects.

Alabama Power, Georgia Power, and Southern Power have contracted to operate and maintain the jointly owned facilities, except for Rocky Mountain and Intercession City, as agents for their respective co-owners. The companies' proportionate share of their plant operating expenses is included in the corresponding operating expenses in the statements of income and each company is responsible for providing its own financing.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined state income tax returns for the States of Alabama, Georgia, and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2008	2007	2006
		(in millions)	
Federal –			
Current	**$628**	$715	$465
Deferred	**177**	11	207
	805	726	672
State –			
Current	**72**	114	110
Deferred	**38**	(5)	(2)
	110	109	108
Total	**$915**	$835	$780

Net cash payments for income taxes in 2008, 2007, and 2006 were $537 million, $732 million, and $649 million, respectively.

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2008	2007
		(in millions)
Deferred tax liabilities –		
Accelerated depreciation	**$5,356**	$4,878
Property basis differences	**968**	950
Leveraged lease basis differences	**306**	479
Employee benefit obligations	**364**	856
Under recovered fuel clause	**516**	443
Premium on reacquired debt	**107**	114
Regulatory assets associated with employee benefit obligations	**869**	303
Regulatory assets associated with asset retirement obligations	**480**	483
Other	**132**	140
Total	**9,098**	8,646
Deferred tax assets –		
Federal effect of state deferred taxes	**354**	305
State effect of federal deferred taxes	**105**	97
Employee benefit obligations	**1,325**	656
Other property basis differences	**144**	147
Deferred costs	**99**	131
Unbilled revenue	**100**	90
Other comprehensive losses	**82**	48
Regulatory liabilities associated with employee benefit obligations	**-**	514
Asset retirement obligations	**480**	483
Other	**279**	259
Total	**2,968**	2,730
Total deferred tax liabilities, net	**6,130**	5,916
Portion included in prepaid expenses (accrued income taxes), net	**(90)**	(106)
Deferred state tax assets	**103**	88
Valuation allowance	**(63)**	(59)
Accumulated deferred income taxes	**$6,080**	$5,839

At December 31, 2008, Southern Company had a State of Georgia net operating loss (NOL) carryforward totaling $1.0 billion, which could result in net state income tax benefits of $57 million, if utilized. However, Southern Company has established a valuation allowance for the potential $57 million tax benefit due to the remote likelihood that the tax benefit will be realized. These NOLs will expire between 2009 and 2021. During 2008, Southern Company utilized $5.8 million in available NOLs, which resulted in a $0.3 million state income tax benefit. The State of Georgia allows the filing of a combined return, which should substantially reduce any additional NOL carryforwards.

At December 31, 2008, the tax-related regulatory assets and liabilities were $972 million and $260 million, respectively. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $23 million in 2008, $23 million in 2007, and $23 million in 2006. At December 31, 2008, all investment tax credits available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

The provision for income taxes differs from the amount of income taxes determined by applying the applicable U.S. federal statutory rate to earnings before income taxes and preferred and preference dividends of subsidiaries, as a result of the following:

	2008	2007	2006
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.6**	2.7	2.9
Synthetic fuel tax credits	**-**	(1.4)	(2.7)
Employee stock plans dividend deduction	**(1.3)**	(1.3)	(1.4)
Non-deductible book depreciation	**0.8**	0.9	1.0
Difference in prior years' deferred and current tax rate	**(0.2)**	(0.2)	(0.3)
AFUDC-Equity	**(1.9)**	(1.4)	(0.7)
Production activities deduction	**(0.4)**	(0.8)	(0.2)
Donations	**-**	(0.8)	-
Other	**(1.0)**	(0.8)	(0.9)
Effective income tax rate	**33.6%**	31.9%	32.7%

Southern Company's effective tax rate increased due to the unavailability of the synthetic fuel tax credits in 2008. The credits were no longer allowed under Internal Revenue Code Section 45K for production after December 31, 2007.

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U. S. production activities as defined in the Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. This increase from 3% in 2006 to 6% in 2007 was one of several

factors that increased Southern Company's 2007 deduction by $32 million over the 2006 deduction. The resulting additional tax benefit was $11 million. The IRS has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, Southern Company reversed the unrecognized tax benefit and adjusted the deduction for all previous years to conform to the agreement which resulted in a decrease in the 2008 deduction when compared to the 2007 deduction. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements.

In 2007, Georgia Power donated 2,200 acres of land in the Tallulah Gorge State Park to the State of Georgia. The estimated value of the donation caused a lower effective income tax rate for the year ended December 31, 2007, when compared to December 31, 2008.

Unrecognized Tax Benefits

FIN 48 requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties. For 2008, the total amount of unrecognized tax benefits decreased by $118 million, resulting in a balance of $146 million as of December 31, 2008.

Changes during the year in unrecognized tax benefits were as follows:

	2008	2007
	(in millions)	
Unrecognized tax benefits at beginning of year	**$264**	$211
Tax positions from current periods	**49**	46
Tax positions from prior periods	**130**	7
Reductions due to settlements	**(297)**	-
Balance at end of year	**$146**	$264

The tax positions from current periods increase for 2008 relate primarily to the Georgia state tax credits litigation and other miscellaneous uncertain tax positions. The tax positions from prior periods increase for 2008 relate primarily to the SILO transactions that was remeasured during the second quarter 2008 and effectively settled in December 2008. The reduction due to settlements relates to the agreement with the IRS on the SILO transactions and the agreement with the IRS regarding the production activities deduction methodology. The results of the effective settlement of the SILO transactions were related to timing differences and therefore had no impact on income. See Note 3 under "Income Tax Matters" for additional information.

Impact on Southern Company's effective tax rate, if recognized, is as follows:

	2008	2007	Change
		(in millions)	
Tax positions impacting the effective tax rate	**$143**	$ 96	$ 47
Tax positions not impacting the effective tax rate	**3**	168	(165)
Balance of unrecognized tax benefits	**$146**	$264	$(118)

The tax positions impacting the effective tax rate increase of $47 million primarily relate to Georgia state tax credit litigation at Georgia Power. The $165 million decrease in tax positions not impacting the effective tax rate relates to the effective settlement of the SILO transactions. See Note 3 under "Income Tax Matters."

Accrued interest for unrecognized tax benefits:

	2008	2007
	(in millions)	
Interest accrued at beginning of year	**$31**	$27
Interest reclassified due to settlements	**(49)**	-
Interest accrued during the year	**33**	4
Balance at end of year	**$15**	$31

Southern Company classifies interest on tax uncertainties as interest expense. The net amount of interest accrued during the period was primarily associated with the SILO transactions and the Georgia state tax credit litigation. Interest reclassified due to settlements relates to the SILO transactions effective settlement agreement and the production activities deduction methodology. These amounts have been reclassified from interest on tax uncertainties to current interest payable.

Southern Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized benefit with respect to a majority of Southern Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The possible settlement of the Georgia state tax credits litigation and/or the conclusion or settlement of federal or state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2004. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2002.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

Southern Company and certain of the traditional operating companies have formed certain wholly-owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to Southern Company or the applicable traditional operating company through the issuance of junior subordinated notes totaling $412 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as "Long-term Debt." Southern Company and such traditional operating companies each consider that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2008, preferred securities of $400 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of scheduled maturities and redemptions of securities due within one year at December 31 was as follows:

	2008	2007
	(in millions)	
Capitalized leases	$ 20	$ 15
Senior notes	565	1,005
Other long-term debt	32	33
Preferred stock	-	125
Total	$ 617	$ 1,178

Debt and preferred stock redemptions, and/or serial maturities through 2013 applicable to total long-term debt are as follows: $617 million in 2009; $1.1 billion in 2010; $825 million in 2011; $1.8 billion in 2012; and $950 million in 2013.

Bank Term Loans

Certain of the traditional operating companies entered into bank term loan agreements in 2008. Georgia Power borrowed $300 million under a three-year term loan agreement and $100 million under a short-term loan agreement. Gulf Power borrowed $110 million under a three-year loan agreement and $50 million under a short-term loan agreement. Mississippi Power also borrowed $80 million under a three-year term loan agreement. The proceeds of these loans were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes. Another Southern Company subsidiary had outstanding long-term bank loans of $184 million at December 31, 2008.

Senior Notes

Southern Company and its subsidiaries issued a total of $2.5 billion of senior notes in 2008. Southern Company issued $600 million, and the traditional operating companies' combined issuances totaled $1.9 billion. The proceeds of these issuances were used to repay maturing long-term and short-term indebtedness and for other general corporate purposes.

At December 31, 2008 and 2007, Southern Company and its subsidiaries had a total of $12.9 billion and $11.4 billion, respectively, of senior notes outstanding. At December 31, 2008 and 2007, Southern Company had a total of $1.1 billion and $900 million, respectively, of senior notes outstanding.

Subsequent to December 31, 2008, Georgia Power issued $500 million long-term senior notes. The proceeds were used to repay long-term and short-term indebtedness and for other general corporate purposes.

Assets Subject to Lien

Each of Southern Company's subsidiaries is organized as a legal entity, separate and apart from Southern Company and its other subsidiaries. Alabama Power and Gulf Power have granted one or more liens on certain of their respective property in connection with the issuance of certain pollution control revenue bonds with an outstanding principal amount of $194 million. There are no agreements or other arrangements among the subsidiary companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its other subsidiaries.

Bank Credit Arrangements

At December 31, 2008, unused credit arrangements with banks totaled $4.2 billion, of which $970 million expires during 2009, $25 million expires in 2011, and $3.2 billion expires in 2012. The following table outlines the credit arrangements by company:

			Expires		
Company	**Total**	**Unused**	**2009**	**2011**	**2012**
		(in millions)			
Alabama Power	$1,256	$1,256	$466	$25	$ 765
Georgia Power	1,345	1,333	225	-	1,120
Gulf Power	120	120	120	-	-
Mississippi Power	99	99	99	-	-
Southern Company	950	950	-	-	950
Southern Power	400	400	-	-	400
Other	60	60	60	-	-
Total	$4,230	$4,218	$970	$25	$3,235

Approximately $84 million of the credit facilities expiring in 2009 allow the execution of term loans for an additional two-year period and $544 million allow execution of one-year term loans. Most of these agreements include stated borrowing rates.

All of the credit arrangements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average one-eighth of 1% or less for Southern Company, the traditional operating companies, and Southern Power. Compensating balances are not legally restricted from withdrawal.

Most of the credit arrangements with banks have covenants that limit debt levels to 65% of total capitalization, as defined in the agreements. For purposes of these definitions, debt excludes the long-term debt payable to affiliated trusts and, in certain arrangements, other hybrid securities. At December 31, 2008, Southern Company, Southern Power, and the traditional operating companies were each in compliance with their respective debt limit covenants.

In addition, the credit arrangements typically contain cross default provisions that would be triggered if the borrower defaulted on other indebtedness above a specified threshold. The cross default provisions are restricted only to the indebtedness, including any guarantee obligations, of the company that has such credit arrangements. Southern Company and its subsidiaries are currently in compliance with all such covenants.

A portion of the $4.2 billion unused credit with banks is allocated to provide liquidity support to the traditional operating companies' variable rate pollution control revenue bonds. The amount of variable rate pollution control revenue bonds requiring liquidity support as of December 31, 2008 was approximately $1.3 billion.

Southern Company, the traditional operating companies, and Southern Power make short-term borrowings primarily through commercial paper programs that have the liquidity support of committed bank credit arrangements. Southern Company and the traditional operating companies may also borrow through various other arrangements with banks. The amounts of commercial paper outstanding and included in notes payable in the balance sheets at December 31, 2008 and December 31, 2007 were $794.3 million and $1.2 billion, respectively. The amounts of short-term bank loans included in notes payable in the balance sheets at December 31, 2008 and December 31, 2007 were $150 million and $113 million, respectively.

During 2008, the peak amount outstanding for short-term debt was $1.7 billion, and the average amount outstanding was $1.1 billion. The average annual interest rate on short-term debt was 2.7% for 2008 and 5.3% for 2007.

Financial Instruments

The traditional operating companies and Southern Power enter into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the traditional operating companies have limited exposure to market volatility in commodity fuel prices and prices of electricity. Southern Power also has limited exposure to market volatility in commodity fuel prices and prices of electricity because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, Southern Power has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. Each of the traditional operating companies manage fuel-hedging programs implemented per the guidelines of their respective state PSCs. In addition to hedges on fuel and purchased power, the traditional operating companies and Southern Power may also enter into hedges of forward electricity sales.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

	2008	2007
	(in millions)	
Regulatory hedges	**$(288)**	$ -
Cash flow hedges	**(1)**	1
Non-accounting hedges	**4**	3
Total fair value	**$(285)**	$4

Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the traditional operating companies' fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives designated as cash flow hedges are mainly used by Southern Power to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transactions. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred. The pre-tax gains/(losses) reclassified from other comprehensive income to revenue and fuel expense were not material for any period presented and are not expected to be material for 2009. Additionally, no material ineffectiveness was recorded in earnings for any period presented. Southern Company has energy-related hedges in place up to and including 2012.

During 2006 and 2007, Southern Company had derivatives in place to reduce its exposure to a phase-out of certain income tax credits related to synthetic fuel production in 2007. In accordance with Internal Revenue Code Section 45K, these tax credits were subject to limitation as the annual average price of oil increases. These derivatives settled on January 1, 2008 and thus there was no income statement impact for the period ended December 31, 2008. At December 31, 2007, the fair value of all derivative transactions related to synthetic fuel production was a $43 million net asset. For 2007 and 2006, the fair value gain/(loss) recognized in other income (expense) to mark the transactions to market was $27 million and $(32) million, respectively.

Southern Company and certain subsidiaries also enter into derivatives to hedge exposure to changes in interest rates. Derivatives related to fixed-rate securities are accounted for as fair value hedges. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings for any period presented.

At December 31, 2008, Southern Company had $1.4 billion notional amount of interest rate derivatives outstanding with net fair value losses of $40 million as follows:

Cash Flow Hedges

	Notional Amount	Variable Rate Received	Weighted Average Fixed Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2008
	(in millions)				*(in millions)*
Cash Flow Hedges on Existing Debt					
Alabama Power*	$576	SIFMA Index	2.69%	February 2010	$(11)
Georgia Power*	301	SIFMA Index	2.22%	December 2009	(3)
Georgia Power	150	3-month LIBOR	2.63%	February 2009	(-)
Georgia Power	300	1-month LIBOR	2.43%	April 2010	(5)
Cash Flow Hedges on Forecasted Debt					
Georgia Power	100	3-month LIBOR	4.98%	February 2019	(21)

* Hedged using the Securities Industry and Financial Markets Association Municipal Swap Index (SIFMA) (formerly the Bond Market Association/PSA Municipal Swap Index)

For fair value hedges, the changes in the fair value of the hedging derivatives are recorded in earnings and are offset by the changes in the fair value of the hedged item. The Company did not have any fair value hedges as of December 31, 2008.

The fair value gains/(losses) for cash flow hedges are recorded in other comprehensive income and are reclassified into earnings at the same time the hedged items affect earnings. In 2008, 2007, and 2006, the Company incurred net gains/(losses) of $(26) million, $9 million, and $1 million, respectively, upon termination of certain interest derivatives at the same time it issued debt. The effective portion of these gains/(losses) has been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative. The Company also settled an interest derivative early because of counterparty credit issues at a loss of $(2) million. This loss is deferred in other comprehensive income and will be amortized into earnings once the forecasted debt is issued in 2009. For 2008, 2007, and 2006, approximately $(19) million, $(15) million, and $(1) million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2009, pre-tax losses of approximately $(34) million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2019 and has deferred realized gains/(losses) that are being amortized through 2037.

Subsequent to December 31, 2008, Georgia Power settled $100 million of hedges related to the forecasted debt issuance in February 2009 at a loss of approximately $16 million. This loss will be amortized into earnings over 10 years.

All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. See Note 10 for additional information.

7. COMMITMENTS

Construction Program

Southern Company is engaged in continuous construction programs, currently estimated to total $5.7 billion in 2009, $5.1 billion in 2010, and $5.8 billion in 2011. These amounts include $187 million, $151 million, and $150 million in 2009, 2010, and 2011, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included herein under "Fuel and Purchased Power Commitments." The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; changes in load projections; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2008, significant purchase commitments were outstanding in connection with the ongoing construction program, which includes new facilities and capital improvements to transmission, distribution, and generation facilities, including those to meet environmental standards.

Long-Term Service Agreements

The traditional operating companies and Southern Power have entered into Long-Term Service Agreements (LTSAs) with General Electric (GE), Alstom Power, Inc., Mitsubishi Power Systems Americas, Inc., and Siemens AG for the purpose of securing maintenance support for the combined cycle and combustion turbine generating facilities owned or under construction by the subsidiaries. The LTSAs cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. The LTSAs are also obligated to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in each contract.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments under the LTSAs, which are subject to price escalation, are made at various intervals based on actual operating hours or number of gas turbine starts of the respective units. Total remaining payments under these agreements for facilities owned are currently estimated at $2.3 billion over the remaining life of the agreements, which are currently estimated to range up to 28 years. However, the LTSAs contain various cancellation provisions at the option of the purchasers.

Georgia Power has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $10 million. The contract contains cancellation provisions at the option of Georgia Power.

Payments made under the LTSAs prior to the performance of any work are recorded as a prepayment in the balance sheets. All work performed is capitalized or charged to expense (net of any joint owner billings), as appropriate based on the nature of the work.

Limestone Commitments

As part of Southern Company's program to reduce sulfur dioxide emissions from its coal plants, the traditional operating companies have begun construction of flue gas desulfurization projects and have entered into various long-term commitments for the procurement of limestone to be used in such equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. Southern Company has a minimum contractual obligation of 7.5 million tons, equating to approximately $299 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are, $13 million in 2009, $35 million in 2010, $35 million in 2011, $36 million in 2012, and $36 million in 2013.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of the generating plants, Southern Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2008. Also, Southern Company has entered into various long-term commitments for the purchase of capacity and electricity. Total estimated minimum long-term obligations at December 31, 2008 were as follows:

	Commitments			
	Natural Gas	Coal	Nuclear Fuel	Purchased Power
			(in millions)	
2009	$1,507	$ 4,608	$187	$ 217
2010	969	3,333	151	239
2011	640	2,666	150	216
2012	611	1,370	152	222
2013	631	1,232	123	191
2014 and thereafter	3,798	3,421	43	1,938
Total	$8,156	$16,630	$806	$3,023

Additional commitments for fuel will be required to supply Southern Company's future needs. Total charges for nuclear fuel included in fuel expense amounted to $147 million in 2008, $144 million in 2007, and $137 million in 2006.

Operating Leases

In 2001, Mississippi Power began the initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel for approximately $370 million. In 2003, the generating facility was acquired by Juniper Capital L.P. (Juniper), whose partners are unaffiliated with Mississippi Power. Simultaneously, Juniper entered into a restructured lease agreement with Mississippi Power. Juniper has also entered into leases with other parties unrelated to Mississippi Power. The assets leased by Mississippi Power comprise less than 50% of Juniper's assets. Mississippi Power is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The initial lease term ends in 2011, and the lease includes a purchase and renewal option based on the cost of the facility at the inception of the lease. Mississippi Power is required to amortize approximately 4% of the initial acquisition cost over the initial lease term. Eighteen months prior to the end of the initial lease, Mississippi Power may elect to renew for 10 years. If the lease is renewed, the agreement calls for Mississippi Power to amortize an additional 17% of the initial completion cost over the renewal period. Upon termination of the lease, at Mississippi Power's option, it may either exercise its purchase option or the facility can be sold to a third party.

The lease provides for a residual value guarantee, approximately 73% of the acquisition cost, by Mississippi Power that is due upon termination of the lease in the event that Mississippi Power does not renew the lease or purchase the assets and that the fair market value is less than the unamortized cost of the asset. A liability of approximately $5 million, $7 million, and $9 million for the fair market value of this residual value guarantee is included in the balance sheets as of December 31, 2008, 2007, and 2006, respectively.

Southern Company also has other operating lease agreements with various terms and expiration dates. Total operating lease expenses were $184 million, $187 million, and $181 million for 2008, 2007, and 2006, respectively. Southern Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

At December 31, 2008, estimated minimum lease payments for noncancelable operating leases were as follows:

	Minimum Lease Payments			
	Plant Daniel	Barges & Rail Cars	Other	Total
		(in millions)		
2009	$29	$66	$ 48	$143
2010	28	46	42	116
2011	28	34	34	96
2012	-	21	25	46
2013	-	18	17	35
2014 and thereafter	-	40	106	146
Total	$85	$225	$272	$582

For the traditional operating companies, a majority of the barge and rail car lease expenses are recoverable through fuel cost recovery provisions. In addition to the above rental commitments, Alabama Power and Georgia Power have obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2010, 2011, and 2013, and the maximum obligations are $61 million, $40 million, and $19 million, respectively. At the termination of the leases, the lessee may either exercise its purchase option, or the property can be sold to a third party. Alabama Power and Georgia Power expect that the fair market value of the leased property would substantially reduce or eliminate the payments under the residual value obligations.

Guarantees

Prior to the Mirant spin-off, Southern Company made separate guarantees to certain counterparties regarding performance of contractual commitments by Mirant's trading and marketing subsidiaries. The total notional amount of the guarantees is not material.

As discussed earlier in this Note under "Operating Leases," Alabama Power, Georgia Power, and Mississippi Power have entered into certain residual value guarantees.

8. COMMON STOCK

Stock Issued

In 2008, Southern Company raised $474 million from the issuance of 14.1 million new common shares under the Company's various stock programs. In 2007, Southern Company raised $379 million from the issuance of 11.6 million new common shares and $159 million from the re-issuance of 5.3 million shares of treasury stock under the Company's various stock programs.

Shares Reserved

At December 31, 2008, a total of 72 million shares were reserved for issuance pursuant to the Southern Investment Plan, the Employee Savings Plan, the Outside Directors Stock Plan, and the Omnibus Incentive Compensation Plan (which includes the stock option plan discussed below).

Stock Option Plan

Southern Company provides non-qualified stock options to a large segment of its employees ranging from line management to executives. As of December 31, 2008, there were 7,009 current and former employees participating in the stock option plan, and there were 33.2 million shares of common stock remaining available for awards under this plan. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant.

Southern Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted in 2008, 2007, and 2006 were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. Southern Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2008**	2007	2006
Expected volatility	**13.1%**	14.8%	16.9%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.8%**	4.6%	4.6%
Dividend yield	**4.5%**	4.3%	4.4%
Weighted average grant-date fair value	**$ 2.37**	$ 4.12	$ 4.15

Southern Company's activity in the stock option plan for 2008 is summarized below:

	Shares Subject To Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2007	34,074,622	$30.77
Granted	7,084,902	35.78
Exercised	(4,112,651)	27.42
Cancelled	(105,600)	34.70
Outstanding at December 31, 2008	**36,941,273**	**$32.09**
Exercisable at December 31, 2008	**24,194,943**	**$30.20**

The number of stock options vested, and expected to vest in the future, as of December 31, 2008 was not significantly different from the number of stock options outstanding at December 31, 2008 as stated above. As of December 31, 2008, the weighted average remaining contractual term for the options outstanding and options exercisable was 6.3 years and 5.1 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $181 million and $165 million, respectively.

As of December 31, 2008, there was $7 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 10 months.

For the years ended December 31, 2008, 2007, and 2006, total compensation cost for stock option awards recognized in income was $20 million, $28 million, and $28 million, respectively, with the related tax benefit also recognized in income of $8 million, $11 million, and $11 million, respectively.

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007, and 2006 was $45 million, $81 million, and $36 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $17 million, $31 million, and $14 million, respectively, for the years ended December 31, 2008, 2007, and 2006.

Southern Company has a policy of issuing shares to satisfy share option exercises. Cash received from issuances related to option exercises under the share-based payment arrangements for the years ended December 31, 2008, 2007, and 2006 was $113 million, $195 million, and $77 million, respectively.

Diluted Earnings Per Share

For Southern Company, the only difference in computing basic and diluted earnings per share is attributable to outstanding options under the stock option plan. The effect of the stock options was determined using the treasury stock method. Shares used to compute diluted earnings per share are as follows:

	Average Common Stock Shares		
	2008	2007	2006
		(in thousands)	
As reported shares	**771,039**	756,350	743,146
Effect of options	**3,809**	4,666	4,739
Diluted shares	**774,848**	761,016	747,885

Common Stock Dividend Restrictions

The income of Southern Company is derived primarily from equity in earnings of its subsidiaries. At December 31, 2008, consolidated retained earnings included $5.3 billion of undistributed retained earnings of the subsidiaries. Southern Power's credit facility contains potential limitations on the payment of common stock dividends; as of December 31, 2008, Southern Power was in compliance with all such requirements.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), Alabama Power and Georgia Power maintain agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the companies' nuclear power plants. The Act provides funds up to $12.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. A company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for Alabama Power and Georgia Power, based on its ownership and buyback interests, is $235 million and $237 million, respectively, per incident, but not more than an aggregate of $35 million per company to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

Alabama Power and Georgia Power are members of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities.

Additionally, both companies have policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible

period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. Alabama Power and Georgia Power each purchase the maximum limit allowed by NEIL, subject to ownership limitations. Each facility has elected a 12-week waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for Alabama Power and Georgia Power under the NEIL policies would be $39 million and $51 million, respectively.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the company or to its bond trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

On January 1, 2008, Southern Company adopted FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value, and requires additional disclosures about fair value measurements. The criterion that is set forth in SFAS No. 157 is applicable to fair value measurement where it is permitted or required under other accounting pronouncements.

SFAS No. 157 defines fair value as the exit price, which is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement. As a means to illustrate the inputs used, SFAS No. 157 establishes a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

The adoption of SFAS No. 157 has not resulted in any significant changes to the methodologies used for fair value measurement. Primarily all the changes in the fair value of assets and liabilities are recorded in other comprehensive income or regulatory assets and liabilities, and thus the impact on earnings is limited to derivatives that do not qualify for hedge accounting.

The fair value measurements performed on a recurring basis and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

At December 31, 2008:	Level 1	Level 2	Level 3	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 22	$ -	$ 22
Nuclear decommissioning trusts[(a)]	498	364	-	862
Cash equivalents and restricted cash	469	-	-	469
Other	2	46	35	83
Total fair value	$969	$432	$35	$1,436
Liabilities:				
Energy-related derivatives	$ -	$307	$ -	$307
Interest rate derivatives	-	40	-	40
Total fair value	$ -	$347	$ -	$347

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

Energy-related derivatives and interest rate derivatives primarily consist of over-the-counter contracts. See Note 6 under "Financial Instruments" for additional information. The nuclear decommissioning trust funds are invested in a diversified mix of equity and fixed income securities. See Note 1 under "Nuclear Decommissioning" for additional information. The cash equivalents and restricted cash consist of securities with original maturities of 90 days or less. "Other" represents marketable securities and certain deferred compensation funds also invested in various marketable securities. All of these financial instruments and investments are valued primarily using the market approach.

Changes in the fair value measurement of the Level 3 items for the year ended December 31, 2008 are as follows:

	Level 3
	Other
	(in millions)
Beginning balance at December 31, 2007	$50
Total gains (losses) - realized/unrealized:	
Included in other comprehensive income	(12)
Purchases, issuances and settlements	1
Transfers in and/or out of Level 3	(4)
Ending balance at December 31, 2008	$35

11. SEGMENT AND RELATED INFORMATION

Southern Company's reportable business segments are the sale of electricity in the Southeast by the four traditional operating companies and Southern Power. Southern Power's revenues from sales to the traditional operating companies were $638 million, $547 million, and $492 million in 2008, 2007, and 2006, respectively. The "All Other" column includes parent Southern Company, which does not allocate operating expenses to business segments. Also, this category includes segments below the quantitative threshold for separate disclosure. These segments include investments in telecommunications, energy-related services, and leveraged lease projects. Also included are investments in synthetic fuels for 2007 and 2006. In addition, see Note 1 under "Related Party Transactions" for information regarding revenues from services for synthetic fuel production that are included in the cost of fuel purchased by Alabama Power and Georgia Power. All other intersegment revenues are not material. Financial data for business segments and products and services are as follows:

Business Segments

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
2008				*(in millions)*			
Operating revenues	**$16,521**	**$ 1,314**	**$(835)**	**$17,000**	**$ 182**	**$ (55)**	**$17,127**
Depreciation and amortization	**1,325**	**89**	**-**	**1,414**	**29**	**-**	**1,443**
Interest income	**32**	**1**	**-**	**33**	**-**	**-**	**33**
Interest expense	**689**	**83**	**-**	**772**	**94**	**-**	**866**
Income taxes	**944**	**93**	**-**	**1,037**	**(122)**	**-**	**915**
Segment net income (loss)	**1,703**	**144**	**-**	**1,847**	**(104)**	**(1)**	**1,742**
Total assets	**44,794**	**2,813**	**(139)**	**47,468**	**1,407**	**(528)**	**48,347**
Gross property additions	**4,058**	**50**	**-**	**4,108**	**14**	**-**	**4,122**

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
2007				*(in millions)*			
Operating revenues	$14,851	$ 972	$(683)	$15,140	$ 380	$(167)	$15,353
Depreciation and amortization	1,141	74	-	1,215	30	-	1,245
Interest income	31	1	-	32	14	(1)	45
Interest expense	685	79	-	764	122	-	886
Income taxes	866	84	-	950	(115)	-	835
Segment net income (loss)	1,582	132	-	1,714	22	(2)	1,734
Total assets	41,812	2,769	(122)	44,459	1,767	(437)	45,789
Gross property additions	3,465	184	(4)	3,645	13	-	3,658

	Electric Utilities						
	Traditional Operating Companies	Southern Power	Eliminations	Total	All Other	Eliminations	Consolidated
2006				*(in millions)*			
Operating revenues	$13,920	$ 777	$(609)	$14,088	$ 413	$(145)	$14,356
Depreciation and amortization	1,098	66	-	1,164	37	(1)	1,200
Interest income	33	2	-	35	7	(1)	41
Interest expense	637	80	-	717	149	-	866
Income taxes	867	82	-	949	(169)	-	780
Segment net income (loss)	1,462	124	-	1,586	(11)	(2)	1,573
Total assets	38,825	2,691	(110)	41,406	1,933	(481)	42,858
Gross property additions	2,561	501	(16)	3,046	26	-	3,072

Products and Services

	Electric Utilities' Revenues			
Year	Retail	Wholesale	Other	Total
		(in millions)		
2008	**$14,055**	**$2,400**	**$545**	**$17,000**
2007	12,639	1,988	513	15,140
2006	11,801	1,822	465	14,088

12. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2008 and 2007 are as follows:

				Per Common Share			
						Trading Price Range	
Quarter Ended	Operating Revenues	Operating Income	Consolidated Net Income	Basic Earnings	Dividends	High	Low
		(in millions)					
March 2008	**$3,683**	**$ 708**	**$359**	**$0.47**	**$0.4025**	**$40.60**	**$33.71**
June 2008	**4,215**	**924**	**417**	**0.54**	**0.4200**	**37.81**	**34.28**
September 2008	**5,427**	**1,405**	**780**	**1.01**	**0.4200**	**40.00**	**34.46**
December 2008	**3,802**	**469**	**186**	**0.24**	**0.4200**	**38.18**	**29.82**
March 2007	$3,409	$ 691	$339	$0.45	$0.3875	$37.25	$34.85
June 2007	3,772	844	429	0.57	0.4025	38.90	33.50
September 2007	4,832	1,382	762	1.00	0.4025	37.70	33.16
December 2007	3,340	409	204	0.27	0.4025	39.35	35.15

Southern Company's business is influenced by seasonal weather conditions.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA

For the Periods Ended December 2004 through 2008

Southern Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006	2005	2004
Operating Revenues (in millions)	**$17,127**	$15,353	$14,356	$13,554	$11,729
Total Assets (in millions)	**$48,347**	$45,789	$42,858	$39,877	$36,955
Gross Property Additions (in millions)	**$4,122**	$3,658	$3,072	$2,476	$2,099
Return on Average Common Equity (percent)	**13.57**	14.60	14.26	15.17	15.38
Cash Dividends Paid Per Share of Common Stock	**$1.6625**	$1.595	$1.535	$1.475	$1.415
Consolidated Net Income (in millions):	**$1,742**	$1,734	$1,573	$1,591	$1,532
Earnings Per Share --					
Basic	**$2.26**	$2.29	$2.12	$2.14	$2.07
Diluted	**2.25**	2.28	2.10	2.13	2.06
Capitalization (in millions):					
Common stock equity	**$13,276**	$ 12,385	$11,371	$ 10,689	$ 10,278
Preferred and preference stock	**1,082**	1,080	744	596	561
Long-term debt	**16,816**	14,143	12,503	12,846	12,449
Total (excluding amounts due within one year)	**$31,174**	$27,608	$24,618	$24,131	$23,288
Capitalization Ratios (percent):					
Common stock equity	**42.6**	44.9	46.2	44.3	44.1
Preferred and preference stock	**3.5**	3.9	3.0	2.5	2.4
Long-term debt	**53.9**	51.2	50.8	53.2	53.5
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Other Common Stock Data:					
Book value per share	**$17.08**	$16.23	$15.24	$14.42	$13.86
Market price per share:					
High	**$40.60**	$39.35	$37.40	$36.47	$33.96
Low	**29.82**	33.16	30.48	31.14	27.44
Close (year-end)	**37.00**	38.75	36.86	34.53	33.52
Market-to-book ratio (year-end) (percent)	**216.6**	238.8	241.9	239.5	241.8
Price-earnings ratio (year-end) (times)	**16.4**	16.9	17.4	16.1	16.2
Dividends paid (in millions)	**$1,279**	$1,204	$1,140	$1,098	$1,044
Dividend yield (year-end) (percent)	**4.5**	4.1	4.2	4.3	4.2
Dividend payout ratio (percent)	**73.5**	69.5	72.4	69.0	68.3
Shares outstanding (in thousands):					
Average	**771,039**	756,350	743,146	743,927	738,879
Year-end	**777,192**	763,104	746,270	741,448	741,495
Stockholders of record (year-end)	**97,324**	102,903	110,259	118,285	125,975
Traditional Operating Company Customers (year-end) (in thousands):					
Residential	**3,785**	3,756	3,706	3,642	3,600
Commercial	**594**	600	596	586	578
Industrial	**15**	15	15	15	14
Other	**8**	6	5	5	5
Total	**4,402**	4,377	4,322	4,248	4,197
Employees (year-end)	**27,276**	26,742	26,091	25,554	25,642

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA

For the Periods Ended December 2004 through 2008

Southern Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006	2005	2004
Operating Revenues (in millions):					
Residential	**$ 5,476**	$ 5,045	$ 4,716	$4,376	$3,848
Commercial	**5,018**	4,467	4,117	3,904	3,346
Industrial	**3,445**	3,020	2,866	2,785	2,446
Other	**116**	107	102	100	92
Total retail	**14,055**	12,639	11,801	11,165	9,732
Wholesale	**2,400**	1,988	1,822	1,667	1,341
Total revenues from sales of electricity	**16,455**	14,627	13,623	12,832	11,073
Other revenues	**672**	726	733	722	656
Total	**$17,127**	$15,353	$14,356	$13,554	$11,729
Kilowatt-Hour Sales (in millions):					
Residential	**52,262**	53,326	52,383	51,082	49,702
Commercial	**54,427**	54,665	52,987	51,857	50,037
Industrial	**52,636**	54,662	55,044	55,141	56,399
Other	**934**	962	920	996	1,005
Total retail	**160,259**	163,615	161,334	159,076	157,143
Sales for resale	**39,368**	40,745	38,460	37,072	34,568
Total	**199,627**	204,360	199,794	196,148	191,711
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.48**	9.46	9.00	8.57	7.74
Commercial	**9.22**	8.17	7.77	7.53	6.69
Industrial	**6.54**	5.52	5.21	5.05	4.34
Total retail	**8.77**	7.72	7.31	7.02	6.19
Wholesale	**6.10**	4.88	4.74	4.50	3.88
Total sales	**8.24**	7.16	6.82	6.54	5.78
Average Annual Kilowatt-Hour Use Per Residential Customer	**13,844**	14,263	14,235	14,084	13,879
Average Annual Revenue Per Residential Customer	**$1,451**	$1,349	$1,282	$1,207	$1,074
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**42,607**	41,948	41,785	40,509	38,622
Maximum Peak-Hour Demand (megawatts):					
Winter	**32,604**	31,189	30,958	30,384	28,467
Summer	**37,166**	38,777	35,890	35,050	34,414
System Reserve Margin (at peak) (percent)	**15.3**	11.2	17.1	14.4	20.2
Annual Load Factor (percent)	**58.7**	57.6	60.8	60.2	61.4
Plant Availability (percent):					
Fossil-steam	**90.5**	90.5	89.3	89.0	88.5
Nuclear	**91.3**	90.8	91.5	90.5	92.8
Source of Energy Supply (percent):					
Coal	**64.0**	67.1	67.2	67.4	65.0
Nuclear	**14.0**	13.4	14.0	14.0	14.5
Hydro	**1.4**	0.9	1.9	3.1	2.9
Oil and gas	**15.4**	15.0	12.9	10.9	10.9
Purchased power	**5.2**	3.6	4.0	4.6	6.7
Total	**100.0**	100.0	100.0	100.0	100.0

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ALABAMA POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Alabama Power Company 2008 Annual Report

The management of Alabama Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This Annual Report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.

Charles D. McCrary
President and Chief Executive Officer

Art P. Beattie
Executive Vice President, Chief Financial Officer, and Treasurer

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Alabama Power Company

We have audited the accompanying balance sheets and statements of capitalization of Alabama Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2008 and 2007, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-133 to II-169) present fairly, in all material respects, the financial position of Alabama Power Company at December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Birmingham, Alabama
February 25, 2009

OVERVIEW

Business Activities

Alabama Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain energy sales in the midst of the current economic downturn, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel prices, capital expenditures, and restoration following major storms. Appropriately balancing the need to recover these increasing costs with customer prices will continue to challenge the Company for the foreseeable future.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The fossil/hydro 2008 Peak Season EFOR of 1.51% was better than the target. The nuclear generating fleet also uses Peak Season EFOR as an indicator of availability and efficient generation fleet operations during the peak season. The nuclear 2008 Peak Season EFOR of 2.78% did not meet the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2008 was better than the target for these reliability measures.

Net income after dividends on preferred and preference stock is the primary component of the Company's contribution to Southern Company's earnings per share goal. The Company's 2008 results compared with its targets for some of these key indicators are reflected in the following chart.

Key Performance Indicator	2008 Target Performance	2008 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR – fossil/hydro	2.75% or less	1.51%
Peak Season EFOR – nuclear	2.00% or less	2.78%
Net Income	$617 million	$616 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2008 reflects the continued management emphasis, as well as the commitment shown by employees, in achieving or exceeding these key performance expectations.

Earnings

The Company's financial performance remained strong in 2008 despite the challenges of a weakening economy and rising costs. The Company's net income after dividends on preferred and preference stock of $616 million in 2008 increased $36 million (6.3%) over the prior year. This improvement was primarily due to an increase in retail base rate revenues resulting from an increase in rates under Rate Stabilization and Equalization Plan (Rate RSE) and Rate Certificated New Plant (Rate CNP) for environmental costs that took effect January 1, 2008, partially offset by higher non-fuel operating expenses and depreciation expense.

The Company's 2007 net income after dividends on preferred and preference stock was $580 million, representing a $62 million (11.9%) increase from the prior year. This improvement was primarily due to an increase in retail base rate revenues resulting from an increase in rates under Rate RSE and Rate CNP for environmental costs that took effect January 1, 2007 as well as favorable weather conditions, partially offset by higher non-fuel operating expenses and increased interest expense.

The Company's 2006 net income after dividends on preferred and preference stock was $518 million, representing a $10 million (1.9%) increase from the prior year. This improvement was primarily due to retail and wholesale revenue growth offset by higher non-fuel operating expenses and increased interest expense.

RESULTS OF OPERATIONS

A condensed income statement follows:

	Amount	Increase (Decrease) from Prior Year		
	2008	**2008**	2007	2006
		(in millions)		
Operating revenues	**$6,077**	**$717**	$345	$367
Fuel	**2,184**	**422**	90	216
Purchased power	**538**	**99**	12	(31)
Other operations and maintenance	**1,259**	**73**	89	53
Depreciation and amortization	**520**	**49**	21	24
Taxes other than income taxes	**307**	**20**	28	9
Total operating expenses	**4,808**	**663**	240	271
Operating income	**1,269**	**54**	105	96
Total other income and (expense)	**(246)**	**2**	(11)	(40)
Income taxes	**368**	**16**	21	46
Net income	**655**	**40**	73	10
Dividends on preferred and preference stock	**39**	**4**	11	-
Net income after dividends on preferred and preference stock	**$ 616**	**$ 36**	$ 62	$ 10

Operating Revenues

Operating revenues for 2008 were $6.1 billion, reflecting a $717 million increase from 2007. The following table summarizes the principal factors that have affected operating revenues for the past three years:

	Amount		
	2008	2007	2006
		(in millions)	
Retail – prior year	**$4,407.0**	$3,995.7	$3,621.4
Estimated change in –			
Rates and pricing	**246.1**	216.3	48.4
Sales growth	**26.8**	(4.9)	35.8
Weather	**(70.4)**	37.6	19.9
Fuel and other cost recovery	**252.8**	162.3	270.2
Retail – current year	**4,862.3**	4,407.0	3,995.7
Wholesale revenues –			
Non-affiliates	**711.9**	627.0	634.6
Affiliates	**308.5**	144.1	216.0
Total wholesale revenues	**1,020.4**	771.1	850.6
Other operating revenues	**194.2**	181.9	168.4
Total operating revenues	**$6,076.9**	$5,360.0	$5,014.7
Percent change	**13.4%**	6.9%	7.9%

Retail revenues in 2008 were $4.9 billion. These revenues increased $455 million (10.3%) in 2008, $411 million (10.3%) in 2007, and $374 million (10.3%) in 2006. These increases were primarily due to increased fuel revenue and base rate increases of 5.6% in

January 2008, 5.3% in January 2007, and 2.6% in January 2006. See FUTURE EARNINGS POTENTIAL – "PSC Matters" herein and Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Fuel rates billed to customers are designed to fully recover fluctuating fuel and purchased power costs over a period of time. Fuel revenues generally have no effect on net income because they represent the recording of revenues to offset fuel and purchased power expenses. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Wholesale revenues from sales to non-affiliated utilities were as follows:

	2008	2007	2006
		(in millions)	
Unit power sales –			
Capacity	**$160**	$151	$154
Energy	**238**	192	198
Total	**398**	343	352
Other power sales –			
Capacity and other	**134**	128	137
Energy	**180**	156	146
Total	**314**	284	283
Total non-affiliated	**$712**	$627	$635

Wholesale revenues from sales to non-affiliates will vary depending on the market cost of available energy compared to the cost of the Company and Southern Company system-owned generation, demand for energy within the Southern Company service territory, and availability of Southern Company system generation.

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to Florida utilities and sales to wholesale customers within the Company's service territory. Capacity revenues under unit power sales contracts reflect the recovery of fixed costs and a return on investment, and under these contracts, energy is generally sold at variable cost. Fluctuations in oil and natural gas prices, which are the primary fuel sources for unit power sales customers, influence changes in these energy sales. However, because energy is generally sold at variable cost, these fluctuations have a minimal effect on earnings. No significant declines in the amount of capacity revenues are scheduled until the termination of the unit power sales contracts in May 2010. In June 2010, the units subject to the unit power sales contracts are expected to return to territorial service. As shown in the table above, unit power sales capacity revenues have ranged from $151 million to $160 million over the last three years. Short-term opportunity energy sales are also included in wholesale energy sales to non-affiliates. These opportunity sales are made at market-based rates that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). In 2008, wholesale revenues from sales to affiliates increased $164.4 million primarily due to a 62.2% increase in kilowatt-hour (KWH) sales to affiliates as a result of an increase in the availability of the Company's generating resources because of a decrease in customer demand within the Company's service territory. In 2007, wholesale revenues from sales to affiliates decreased $71.9 million primarily due to a 37.0% decrease in KWH sales to affiliates as a result of a decrease in the availability of the Company's generating resources because of an increase in customer demand within the Company's service territory. In 2006, wholesale revenues decreased $73.0 million primarily due to a 16.7% decrease in price and a 10.3% decrease in KWH sales to affiliates as a result of a decrease in the availability of the Company's generating resources because of an increase in customer demand within the Company's service territory. Excluding the capacity revenues, these transactions do not have a significant impact on earnings since the energy is generally sold at marginal cost and energy purchases are generally offset by energy revenues through the Company's energy cost recovery clause (Rate ECR).

Other operating revenues in 2008 increased $12.4 million (6.8%) from 2007 primarily due to an $11.7 million increase in revenues from gas-fueled co-generation steam facilities. In 2007, other operating revenues increased $13.5 million (8.0%) from 2006 primarily due to a $4.0 million increase in revenues from electric property associated with pole attachment and building rentals, a $2.6 million increase in transmission revenues, and a $2.5 million increase in revenues from gas-fueled co-generation steam facilities. In 2006,

other operating revenues decreased $17.6 million (9.5%) from 2005 primarily due to a decrease of $14.6 million in revenues from gas-fueled co-generation steam facilities mainly as a result of lower gas prices. Since co-generation steam revenues are generally offset by fuel expense, these revenues did not have a significant impact on earnings for any year reported.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2008 and the percent change by year were as follows:

	KWHs	Percent Change		
	2008	**2008**	2007	2006
	(in billions)			
Residential	**18.4**	**(2.6)%**	1.3%	3.1%
Commercial	**14.5**	**(1.4)**	2.8	2.1
Industrial	**22.1**	**(3.2)**	(1.6)	(0.7)
Other	**0.2**	**0.2**	0.7	0.4
Total retail	**55.2**	**(2.5)**	0.5	1.2
Wholesale -				
Non-affiliates	**15.2**	**(3.6)**	(1.3)	3.5
Affiliates	**5.3**	**62.2**	(37.0)	(10.3)
Total wholesale	**20.5**	**7.6**	(10.0)	(0.3)
Total energy sales	**75.7**	**0.0**	(2.4)	0.8

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Retail energy sales in 2008 were 2.5% less than in 2007. Energy sales were down in 2008 across all classes of customers. Residential and commercial sales decreased 2.6% and 1.4%, respectively, due primarily to milder weather in 2008 compared to 2007. Industrial sales decreased 3.2% during the year primarily as a result of decreased customer demand in the chemical and pipeline, and textiles and food sectors, as a result of a slowing economy that worsened during the fourth quarter of 2008.

Retail energy sales in 2007 were 0.5% higher than in 2006. Energy sales in the residential and commercial sectors led the growth with a 1.3% and a 2.8% increase, respectively, due primarily to weather-driven increased demand. Industrial sales decreased 1.6% during the year primarily as a result of decreased sales demand in textiles and food, primary metals, and chemical sectors.

Retail energy sales in 2006 were 1.2% higher than in 2005. Energy sales in the residential and commercial sectors led the growth with a 3.1% and a 2.1% increase, respectively, due primarily to weather-driven increased demand. Industrial sales decreased 0.7% as several large textile facilities discontinued or substantially reduced their operations in 2006. In addition, industrial sales decreased due to pulp and paper customers utilizing self-generation as a result of lower gas prices during the year compared to 2005.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market. Details of the Company's electricity generated and purchased were as follows:

	2008	2007	2006
Total generation *(billions of KWHs)*	**70.0**	69.8	72.0
Total purchased power *(billions of KWHs)*	**9.2**	9.6	8.9
Sources of generation *(percent)* –			
Coal	**66**	69	68
Nuclear	**20**	19	19
Gas	**11**	10	9
Hydro	**3**	2	4
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**2.94**	2.14	2.09
Nuclear	**0.50**	0.50	0.47
Gas	**8.30**	7.43	7.87
Average cost of fuel, generated *(cents per net KWH)*	**3.00**	2.36	2.27
Average cost of purchased power *(cents per net KWH)*	**7.44**	6.07	5.98

Fuel and purchased power expenses were $2.7 billion in 2008, an increase of $521.5 million (23.7%) above the prior year costs. This increase was the result of a $560.8 million increase in the cost of fuel, offset by a $39.3 million decrease related to the volume of KWHs generated and purchased.

Fuel and purchased power expenses were $2.2 billion in 2007, an increase of $101.9 million (4.9%) above the prior year costs. This increase was the result of a $70.3 million increase in the cost of fuel and a $31.6 million increase related to the volume of KWHs generated and purchased.

Fuel and purchased power expenses were $2.1 billion in 2006, an increase of $184.1 million (9.6%) above the prior year costs. This increase was the result of a $128.7 million increase in the cost of fuel and a $55.4 million increase related to the volume of KWHs generated and purchased.

Purchased power consists of purchases from affiliates in the Southern Company system and non-affiliated companies. Purchased power transactions among the Company, its affiliates, and non-affiliates will vary from period to period depending on demand and the availability and variable production cost of generating resources at each company. Purchased power from non-affiliates increased $81.9 million (84.5%) in 2008 due to a 67.9% increase in the amount of energy purchased. In 2007, purchased power from non-affiliates decreased $27.1 million (21.8%) due to a 22.6% decrease in the amount of energy purchased over the previous year. In 2006, purchased power from non-affiliates decreased $64.7 million (34.3%) due to a 26.8% decrease in the amount of energy purchased and a 10.3% decrease in purchased power prices over the previous year.

Over the last several years, coal prices have been influenced by a worldwide increase in demand from developing countries, as well as increases in mining and fuel transportation costs. In the first half of 2008, coal prices reached unprecedented high levels primarily due to increased demand following more moderate pricing in 2006 and 2007. Despite these fluctuations, fuel inventories have been adequate and fuel supply markets have been sufficient to meet expected fuel requirements. Demand for natural gas in the United States also increased in 2007 and the first half of 2008. However, natural gas supplies increased in the last half of 2008 as a result of increased production and higher storage levels due in part to weak industrial demand. Both coal and natural gas prices moderated in the second half of 2008 as the result of a recessionary economy. During 2008, uranium prices continued to moderate from the highs set during 2007. While worldwide uranium production levels appear to have increased slightly since 2007, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel and purchased power expenses generally do not affect net income, since they are offset by fuel revenues under the Company's Rate ECR. The Company, along with the Alabama Public Service Commission (PSC), continuously monitors the under/over recovered balance to determine whether adjustments to billing rates are required. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Retail Fuel Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Other Operations and Maintenance Expenses

In 2008, other operations and maintenance expenses increased $72.7 million (6.1%) primarily due to a $27.4 million increase in steam production expense related to environmental mandates (which were offset by revenues associated with Rate CNP environmental) and scheduled outage costs, a $22.9 million increase in nuclear production expense related to operations and scheduled outage costs, and a $19.9 million increase in transmission and distribution expense related to overhead line clearing costs. In 2007, other operations and maintenance expenses increased $89.3 million (8.1%) primarily due to a $28.5 million increase in steam production expense related to environmental mandates and scheduled outage costs, a $19.6 million increase in transmission and distribution expense related to overhead line clearing costs, a $19.0 million increase in administrative and general expenses related to an increase in the expenses for the injuries and damages reserve, outside services, and employee benefits, an $8.1 million increase in nuclear production expense related to scheduled outage cost, and a $4.7 million increase in customer accounts expense associated with customer service expenses. In 2006, other operations and maintenance expenses increased $52.8 million (5.1%) primarily due to an $18.8 million increase in administrative and general expenses related to employee benefits, a $10.1 million increase in nuclear production expense related to both routine operation and scheduled outage costs, a $9.8 million increase in transmission and distribution expense related to overhead and underground line costs, and a $5.4 million increase in steam production expense related to environmental costs.

Depreciation and Amortization

Depreciation and amortization expenses increased $48.9 million (10.4%) in 2008, $20.5 million (4.5%) in 2007, and $24.5 million (5.7%) in 2006, primarily due to additions to property, plant, and equipment related to environmental mandates (which were offset by revenues associated with Rate CNP environmental) and distribution projects. During 2008, a depreciation study was completed based on information as of December 31, 2007. The study was filed with the FERC on October 29, 2008 and was also provided to the Alabama PSC. The proposed rates result in an expected increase in depreciation expense for 2009 of approximately $29 million.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $19.9 million (7.0%) in 2008, $28.4 million (11.0%) in 2007, and $9.3 million (3.7%) in 2006, primarily due to increases in state and municipal public utility license taxes which are directly related to the increase in retail revenues.

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) increased $10.1 million (28.5%) in 2008 and $17.2 million (94.1%) in 2007, primarily due to increases in the amount of construction work in progress related to environmental mandates at generating facilities and transmission and distribution projects compared to the prior years. In 2006, AFUDC decreased $2.0 million (10.0%) primarily due to the timing of construction expenditures compared to the prior year. See Note 1 to the financial statements under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

Income Taxes

Income taxes increased $16.6 million (4.7%) in 2008, primarily due to higher pre-tax income partially offset by the tax benefit associated with an increase in AFUDC and a decrease in expense related to tax contingencies.

Income taxes increased $20.9 million (6.3%) in 2007, primarily due to higher pre-tax income partially offset by the tax benefit associated with an increase in AFUDC and an increase in the Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 199 production activities deduction.

Income taxes increased $45.6 million (16.0%) in 2006, primarily due to higher pre-tax income and the impact of a 2005 accounting order approved by the Alabama PSC to return certain regulatory liabilities related to deferred taxes to Alabama Power's retail customers. See Note 5 to the financial statements for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of costs. Retail rates may be adjusted annually based on historical or projected costs, including estimates for inflation. When historical costs are included, or when inflation exceeds the projected costs used in rate regulation or market-based prices, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, the income tax laws are based on historical costs. Any adverse effect of inflation on the Company's results of operations has not been substantial. See Note 3 to financial statements under "Retail Regulatory Matters – Rate RSE" for additional information.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail and wholesale customers within its traditional service area located in the State of Alabama in addition to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Alabama PSC under cost-based regulatory principles. Prices for wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "FERC Matters" and "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales during the current economic downturn, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service area. Recent recessionary conditions have negatively impacted sales growth. The timing and extent of the economic recovery will impact future earnings.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental statutes and regulations are adopted or modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that it had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama after the Company was dismissed from the original action. In this lawsuit, the EPA alleged that NSR violations occurred at five coal-fired generating facilities operated by the Company. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between the Company and the EPA, resolving a portion of the Company's lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required the Company to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by the Company, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted the Company's motion for summary judgment and entered final judgment in favor of the Company on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Company's case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of the Company regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case and the ultimate outcome of this matter cannot be determined at this time.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2008, the Company had invested approximately $2.3 billion in capital projects to comply with these requirements, with annual totals of $617 million, $469 million, and $260 million for 2008, 2007, and 2006, respectively. The Company expects that capital expenditures to assure compliance with existing and new statutes and regulations will be an additional $584 million, $131 million, and $59 million for 2009, 2010, and 2011, respectively. The Company's compliance strategy can be affected by changes to existing environmental laws, statutes, and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Compliance with any new federal or state legislation or regulations related to global climate change, air quality, combustion byproducts, including coal ash, or other environmental and health concerns could also significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2008, the Company had spent approximately $2.0 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x)

emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently being installed at several plants to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2004, the EPA designated nonattainment areas under an eight-hour ozone standard. The Birmingham area was originally designated as nonattainment under the eight-hour ozone standard, but has since been redesignated as an attainment area by the EPA, and a maintenance plan to address future exceedances of the standard has been approved. On March 12, 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard which will likely result in designation of new nonattainment areas within the Company's service territory. The EPA is expected to publish those designations in 2010, and require state implementation plans for any nonattainment areas by 2013.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for several areas within the Company's service territory, including the Birmingham area. State plans for addressing the nonattainment designations for this standard were due by April 5, 2008 but have not been finalized. These state plans could require further reductions in SO_2 and NO_x emissions from power plants. In September 2006, the EPA published a final rule which increased the stringency of the 24-hour average fine particulate matter air quality standard. On December 18, 2008, the EPA designated the Birmingham area as nonattainment for the 24-hour standard. A state implementation plan for this nonattainment area is due in 2012.

The EPA issued the final Clean Air Interstate Rule (CAIR) in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Alabama, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating CAIR in its entirety and remanding it to the EPA for further action consistent with its opinion. On December 23, 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit altered its July decision in response to a rehearing petition and remanded CAIR to the EPA without vacatur, thereby leaving CAIR compliance requirements in place while the EPA develops a revised rule. The State of Alabama has completed its plan to implement CAIR. Emission reductions are being accomplished by the installation of emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances. The full impact of the court's remand and the outcome of the EPA's future rulemaking in response cannot be determined at this time.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress by 2018 toward the natural conditions goal. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the CAIR satisfies BART requirements for SO_2 and NO_x. Extensive studies were performed for each of the Company's affected units to demonstrate that additional particulate matter controls are not necessary under BART. The state of Alabama has determined that no additional SO_2 controls beyond CAIR are needed to satisfy reasonable progress. States have completed or are currently completing implementation plans that contain strategies for BART and any other measures required to achieve the first phase of reasonable progress.

The impacts of the eight-hour ozone nonattainment designations, the fine particulate matter nonattainment designations, and the Clean Air Visibility Rule on the Company cannot be determined at this time and will depend on the resolution of any pending legal challenges and the development and implementation of rules at the state level.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2 and NO_x emission controls within the next several years to ensure continued compliance with applicable air quality requirements.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The final Clean Air Mercury Rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners alleged that the EPA was not authorized to establish a cap-and-trade program for mercury emissions and instead the EPA must establish maximum achievable control technology standards for coal-fired electric utility steam generating units. On February 8, 2008, the court ruled in favor of the petitioners and vacated the Clean Air Mercury Rule. The

Company's overall environmental compliance strategy relies primarily on a combination of SO_2 and NO_x controls to reduce mercury emissions. Any significant changes in the strategy will depend on the outcome of any appeals and/or future federal and state rulemakings. Future rulemakings necessitated by the court's decision could require emission reductions more stringent than those required by the Clean Air Mercury Rule.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. In January 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to the EPA for revisions. The decision has been appealed to the U.S. Supreme Court. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions and renewable energy standards continue to be strongly considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. The ultimate outcome of these proposals cannot be determined at this time; however, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that will follow from this response may have implications for both new and existing stationary sources, such as power plants. The ultimate outcome of these rulemaking activities cannot be determined at this time; however, as with the current legislative proposals, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In addition, some states are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. For example, on June 25, 2008, Florida's Governor signed comprehensive energy-related legislation that includes authorization for the Florida Department of Environmental Protection to adopt rules for a cap-and-trade regulatory program to address greenhouse gas emissions from electric utilities, conditioned upon their ratification by the legislature no sooner than the 2010 legislative session. This legislation also authorizes the Florida PSC to adopt a renewable portfolio standard for public utilities, subject to legislative ratification. The impact of any similar state legislation on the Company will depend on the future development, adoption, legislative ratification, implementation, and potential legal challenges to rules governing greenhouse gas emissions and mandates regarding the use of renewable energy, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2012 timeframe, with a conclusion to this round of negotiations targeted for the end of 2009. The outcome and impact of the international negotiations cannot be determined at this time.

The Company continues to evaluate its future energy and emission profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $3.9 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Generation Interconnection Agreements

In November 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to two previously executed interconnection agreements with the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $11.0 million previously paid for interconnection facilities. No other similar complaints are pending with the FERC.

In January 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order required the modification of Tenaska's interconnection agreements, under the provisions of the order, the Company determined that no refund was payable to Tenaska. The Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of FERC's methodology for determining the amount of refunds. The requested rehearings

were denied and the Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

Hydro Relicensing

In July 2005, the Company filed two applications with the FERC for new 50-year licenses for the Company's seven hydroelectric developments on the Coosa River (Weiss, Henry, Logan Martin, Lay, Mitchell, Jordan, and Bouldin) and for the Lewis Smith and Bankhead developments on the Warrior River. The FERC licenses for all of these nine projects expired in July and August of 2007. Since the FERC did not act on the Company's new license applications prior to the expiration of the existing licenses, the FERC is required by law to issue annual licenses to the Company, under the terms and conditions of the existing license, until action is taken on the new license applications. The FERC issued an annual license for the Coosa developments in August 2007 and issued an annual license for the Warrior developments in September 2007. These annual licenses are automatically renewed each year without further action by the FERC to allow the Company to continue operation of the projects under the terms of the previous license while the FERC completes review of the applications for new licenses.

In 2006, the Company initiated the process of developing an application to relicense the Martin hydroelectric project located on the Tallapoosa River. The current Martin license will expire in 2013 and the application for a new license is expected to be filed with the FERC in 2011.

Upon or after the expiration of each license, the U.S. Government, by act of Congress, may take over the project or the FERC may relicense the project either to the original licensee or to a new licensee. The FERC may grant relicenses subject to certain requirements that could result in additional costs to the Company. The timing and final outcome of the Company's relicense applications cannot now be determined.

PSC Matters

Retail Rate Adjustments

In October 2005, the Alabama PSC approved a revision to Rate RSE requested by the Company. Effective January 2007 and thereafter, Rate RSE adjustments are based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4% per year and any annual adjustment is limited to 5%. Retail rates remain unchanged when the return on retail common equity is projected to be between 13.0% and 14.5%. If the Company's actual retail return on common equity is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return on common equity fall below the allowed equity return range.

On October 7, 2008, the Alabama PSC approved a corrective rate package primarily providing for adjustments associated with customer charges to certain existing rate structures. This package, effective in January 2009, is expected to generate additional annual revenues of approximately $168 million. The Company agreed to a moratorium on any increase in rates in 2009 under Rate RSE. On December 1, 2008, the Company made its submission of projected data for calendar year 2009. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate RSE" for further information.

The Company's retail rates, approved by the Alabama PSC, also provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated power purchase agreements (PPAs) under Rate CNP. In April 2006, an annual adjustment to Rate CNP, associated with PPAs, increased retail rates by approximately 0.5%, or $19 million annually. There was no rate adjustment associated with the annual adjustment to Rate CNP, associated with PPAs, or the true-up adjustment in April 2007 and 2008. There will be no adjustment to the current Rate CNP to recover certificated PPA costs in April 2009. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate CNP" for additional information.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism, based on forward-looking information provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased due to environmental costs approximately 1.2% in January 2006, 0.6% in January 2007, and 2.4% in January 2008. On October 7, 2008, the Alabama PSC approved a corrective rate package primarily providing for adjustments associated with customer charges to certain existing rate structures. As a part of the Alabama PSC approval of the corrective rate package, the Alabama PSC and the Company agreed to defer any environmental rate increase from 2009 to 2010. This

deferral will have an immaterial impact on annual cash flows, and will have no significant effect on the Company's revenues or net income. On December 1, 2008, the Company made its submission of projected data for calendar year 2009. See Note 3 to the financial statements under "Retail Regulatory Matters" for further information.

Retail Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. The Company, along with the Alabama PSC, will continue to monitor the under recovered fuel cost balance to determine whether an additional adjustment to billing rates is required.

In June 2007, the Alabama PSC ordered the Company to increase its Rate ECR factor to 3.100 cents per KWH effective with billings beginning July 2007 for the 30-month period ending December 2009. The previous rate of 2.400 cents per KWH had been in effect since January 2006. This increase was intended to permit recovery of energy costs based on an estimate of future energy cost, as well as the collection of the existing under recovered energy cost by the end of 2009. During the recovery period, the Company was allowed to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation. In the event the application of this increased Rate ECR factor results in an over recovered position during this period, the Company would pay interest on any such over recovered balance at the same rate used to derive the carrying cost.

On October 7, 2008, the Alabama PSC approved an increase in the Company's Rate ECR factor to 3.983 cents per KWH for a 24-month period beginning with October 9, 2008 billings. Thereafter, the Rate ECR factor is 5.910 cents per KWH, absent a contrary order by the Alabama PSC. The previous rate of 3.100 cents per KWH had been in effect since June 2007. During the 24-month period, the Company will be allowed to continue to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation. In the event the application of this increased Rate ECR factor results in an over recovered position during this period, the Company will pay interest on any such over recovered balance at the same rate used to derive the carrying cost.

The Company's under recovered fuel costs as of December 31, 2008 totaled $305.8 million as compared to $279.8 million at December 31, 2007. As a result of the Alabama PSC orders, the Company classified $180.9 million and $81.7 million of the under recovered regulatory clause revenues as deferred charges and other assets in the balance sheets as of December 31, 2008 and December 31, 2007, respectively. This classification is based on an estimate which includes such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of the recovery of the under recovered fuel costs.

Rate ECR revenues, as recorded on the financial statements, are adjusted for the difference in actual recoverable costs and amounts billed in current regulated rates. Accordingly, this approved increase in the billing factor will have no significant effect on the Company's revenues or net income, but will increase annual cash flow.

Natural Disaster Cost Recovery

Based on an order from the Alabama PSC, the Company maintains a reserve for operations and maintenance expense to cover the cost of damages from major storms to its transmission and distribution facilities. See Note 1 and Note 3 to the financial statements under "Natural Disaster Reserve" and "Retail Regulatory Matters - Natural Disaster Cost Recovery," respectively, for additional information on these reserves.

In December 2005, the Alabama PSC approved a request by the Company to replenish the depleted natural disaster reserve (NDR) due to hurricanes in 2005 and allow for recovery of future natural disaster costs. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of uninsured storm damage exceed any established reserve balance. The order also approved a separate monthly NDR charge consisting of two components beginning in January 2006. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. Assuming no additional storms, the Company currently expects that the target reserve balance could be achieved within three years. The second component of the NDR charge is intended to allow recovery of any existing deferred hurricane related operations and maintenance costs and any future reserve deficits over a 24-month period. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account.

At December 31, 2008, the Company had an accumulated balance of $33.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities." In June 2007, the Company fully recovered its storm costs of $51.3 million resulting from previous hurricanes. As a result, customer rates decreased by this portion of the NDR charge effective in July 2007.

As revenue from the NDR charge is recognized, an equal amount of operations and maintenance expenses related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income but will increase annual cash flow.

Income Tax Matters

Legislation

On February 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA include an extension of bonus depreciation and multiple renewable energy incentives. These incentives could have a significant impact on the Company's future cash flow and net income. Additionally, the ARRA includes programs for renewable energy, transmission and smart grid enhancement, fossil energy and research, and energy efficiency and conservation. The ultimate impact cannot be determined at this time.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 (production activities deduction) of the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The Internal Revenue Service has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction to conform to the agreement. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Other Matters

In accordance with Financial Accounting Standards Board (FASB) Statement No. 87, Employers' Accounting for Pensions, the Company recorded non-cash pre-tax pension income of approximately $26 million, $17 million, and $13 million in 2008, 2007, and 2006, respectively. Postretirement benefit costs for the Company were $23 million, $27 million, and $28 million in 2008, 2007, and 2006, respectively. Such amounts are dependent on several factors including trust earnings and changes to the plans. A portion of pension and postretirement benefit costs is capitalized based on construction-related labor charges. Pension and postretirement benefit costs are a component of the regulated rates and generally do not have a long-term effect on net income. For more information regarding pension and postretirement benefits, see Note 2 to the financial statements.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Alabama PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's financial statements than they would on a non-regulated company.

As reflected in Note 1 to the financial statements under "Regulatory Assets and Liabilities," significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's results of operations.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with generally accepted accounting principles, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or Alabama Department of Revenue interpretations of existing regulations.
- Identification of sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of new or existing matters through the legislative process, the court systems, the IRS, the FERC, or the EPA.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, power delivery volume and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2008. Throughout the recent turmoil in the financial markets, the Company has maintained adequate access to capital without drawing on any of its committed bank credit arrangements used to support its commercial paper programs and variable rate pollution control revenue bonds. The Company has continued to issue commercial paper at reasonable rates. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. No material changes in bank credit arrangements have occurred, although market rates for committed credit have increased and the Company may be subject to higher costs as its existing facilities are replaced or renewed. The Company's interest cost for short-term debt has decreased as market short-term interest rates have declined. The ultimate impact on future financing costs as a result of the financial turmoil cannot be determined at this time. The Company experienced no material counterparty credit losses as a result of the turmoil in the financial markets. See "Sources of Capital" and "Financing Activities" herein for additional information.

The Company's investments in pension and nuclear decommissioning trust funds declined in value as of December 31, 2008. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time. The Company does not expect any changes to the funding obligations to the nuclear decommissioning trust at this time.

Net cash provided from operating activities in 2008 totaled $1.2 billion, an increase of $30 million as compared to 2007. Significant changes in operating cash flow for 2008 included an increase in the use of funds for fossil fuel inventory and payment of operating expenses along with a higher receivables balance as compared 2007. This use of funds was offset by an increase in cash from net income as previously discussed and higher depreciation expense along with a decrease in the payments for federal taxes as compared to 2007. Net cash provided from operating activities in 2007 totaled $1.2 billion, an increase of $194 million as compared to 2006. The increase was primarily due to an increase in net income resulting from price increases, an increase in deferred taxes and the timing of payments related to operating expenses. Net cash provided from operating activities in 2006 totaled $956 million, an increase of $48 million as compared to 2005. The increase was primarily due to higher recovery rates for fuel and purchased power partially offset by the timing of payments for operating expenses.

Net cash used for investing activities totaled $1.6 billion, $1.3 billion, and $1.0 billion for 2008, 2007, and 2006, respectively, primarily due to gross property additions to utility plant of $1.5 billion, $1.2 billion and $0.9 billion for 2008, 2007, and 2006, respectively. These additions were primarily related to construction of transmission and distribution facilities, replacement of steam generation equipment, purchases of nuclear fuel, and environmental mandates.

Net cash provided from financing activities totaled $375 million in 2008, $162 million in 2007, and $14 million in 2006 primarily due to long term debt issuances and cash raised from common stock sales in excess of redemptions of securities and dividends paid. Fluctuations in cash flow from financing activities vary from year to year based on capital needs and securities redeemed.

Significant balance sheet changes for 2008 include an increase of $966 million in gross plant and an increase of $855 million in long-term debt, primarily due to an increase in environmental-related equipment. Other significant balance sheet changes were a result of a decline in the market value of the Company's pension trust and nuclear decommissioning trust funds, impacting the Company's other regulatory assets and liabilities. See Note 1 to the financial statements under "Regulatory Assets and Liabilities" and "Nuclear

Decommissioning" and Note 2 under "Pension Plans" for additional information. In 2007, significant balance sheet changes included an increase of $671 million in gross plant and an increase of $602 million in long-term debt, primarily due to an increase in environmental-related equipment.

The Company's ratio of common equity to total capitalization, including short-term debt, was 42.5% in 2008, 42.5% in 2007, and 42.1% in 2006. See Note 6 to the financial statements for additional information.

The Company has maintained investment grade credit ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and preference stock. See SELECTED FINANCIAL AND OPERATING DATA for additional information regarding the Company's securities ratings.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, unsecured debt, common stock, preferred stock, and preference stock. However, the type and timing of any financings will depend on market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Alabama PSC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission under the Securities Act of 1933, as amended. The amounts of securities authorized by the Alabama PSC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

The Company's current liabilities sometimes exceed current assets because of the Company's debt due within one year and the periodic use of short-term debt as a funding source primarily to meet scheduled maturities of long-term debt as well as cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At December 31, 2008, the Company had approximately $28.2 million of cash and cash equivalents and $1.3 billion of unused credit arrangements with banks, as described below. In addition, the Company has substantial cash flow from operating activities and access to the capital markets, including a commercial paper program, to meet liquidity needs.

The Company maintains committed lines of credit in the amount of $1.3 billion, of which $466 million will expire at various times during 2009. $379 million of the credit facilities expiring in 2009 allow for the execution of term loans for an additional one-year period. $765 million of credit facilities expire in 2012. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from such issuances for the benefit of any other traditional operating company. The obligations of each company under these arrangements are several and there is no cross affiliate credit support.

As of December 31, 2008, the Company had $25 million of commercial paper outstanding. As of December 31, 2007, the Company had no commercial paper outstanding.

Financing Activities

During 2008, the Company issued $850 million of senior notes and incurred obligations related to the issuance of $254 million of tax-exempt bonds. In addition, the Company issued a total of 7.5 million shares of its common stock at $40.00 per share and realized proceeds of $300 million. The proceeds of these issuances were used to repay short-term indebtedness, to fund certain pollution control, environmental improvement facilities and solid waste disposal facilities, and for general corporate purposes.

Also during 2008, the Company paid at maturity $410 million of senior notes and redeemed 1,250 shares of its Flexible Money Market Class A Preferred Stock (Series 2003A), Stated Capital $100,000 Per Share ($125 million aggregate value).

Also during 2008, the Company entered into $330 million notional amount of interest rate swaps related to variable rate pollution control revenue bonds to hedge changes in interest rates for the period February 2008 through February 2010. The weighted average fixed payment rate on these hedges is 2.49% and the Company now has a total of $576 million of such hedges in place, with an overall weighted average fixed payment rate of 2.69%.

The Company converted its $246.5 million obligation related to auction rate pollution control revenue bonds from an auction rate mode to fixed rate interest modes. With the completion of this conversion in March 2008, none of the outstanding securities or obligations of the Company is subject to an auction rate mode.

Also during 2008, the Company was required to purchase a total of approximately $11 million of variable rate pollution control revenue bonds that were tendered by investors, all of which were subsequently remarketed.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are primarily for fuel purchases, fuel transportation and storage, emission allowances, and energy price risk management. At December 31, 2008, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $2 million. At December 31, 2008, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $99 million. Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Due to cost-based rate regulations, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into forward starting interest rate swaps and other derivatives that have been designated as hedges. The weighted average interest rate on $250 million of long-term variable interest rate exposure that has not been hedged at January 1, 2009 was 2.34%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $2.5 million at January 1, 2009. For further information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The Company has implemented fuel hedging programs per the guidelines of the Alabama PSC.

In addition, the Company's Rate ECR allows the recovery of specific costs associated with the sales of natural gas that become necessary due to operating considerations at the Company's electric generating facilities. Rate ECR also allows recovery of the cost of financial instruments used for hedging market price risk up to 75% of the budgeted annual amount of natural gas purchases. The Company may not engage in natural gas hedging activities that extend beyond a rolling 42-month window. Also, the premiums paid for natural gas financial options may not exceed 5% of the Company's natural gas budget for that year.

The changes in fair value of energy-related derivative contracts were as follows at December 31:

	2008 Changes	2007 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (0.4)**	$(32.6)
Contracts realized or settled	**(44.0)**	31.5
Current period changes[a]	**(47.5)**	0.7
Contracts outstanding at the end of the period, assets (liabilities), net	**$(91.9)**	$ (0.4)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The decrease in the fair value positions of the energy-related derivative contracts for the year-ended December 31, 2008 was $91.5 million, substantially all of which is due to natural gas positions. This change is attributable to both the volume and prices of natural gas. At December 31, 2008, the Company had a net hedge volume of 44.5 billion cubic feet (Bcf) with a weighted average contract cost approximately $2.12 per million British thermal units (mmBtu) above market prices, and 27.4 Bcf at December 31, 2007 with a weighted average contract cost approximately $0.02 per mmBtu above market prices. The majority of the natural gas hedges are recovered through the fuel cost recovery clauses.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

	2008	2007
	(in millions)	
Regulatory hedges	**$(91.9)**	$(0.7)
Cash flow hedges	**-**	0.5
Non-accounting hedges	**-**	(0.2)
Total fair value	**$(91.9)**	$(0.4)

Energy-related derivative contracts which are designated as regulatory hedges relate to the Company's fuel hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clauses. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented.

The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

	December 31, 2008 Fair Value Measurements			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ -	$ -	$ -	$ -
Level 2	(91.9)	(71.4)	(20.5)	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(91.9)	$(71.4)	$(20.5)	$ -

As part of the adoption of FASB Statement No. 157, "Fair Value Measurements" to increase consistency and comparability in fair value measurements and related disclosures, the table above now uses the three-tier fair value hierarchy, as discussed in Note 10 to the financial statements, as opposed to the previously used descriptions "actively quoted," "external sources," and "models and other methods." The three-tier fair value hierarchy focuses on the fair value of the contract itself, whereas the previous descriptions focused on the source of the inputs. Because the Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, the valuations of those contracts now appear in Level 2; previously they were shown as "actively quoted."

The Company is exposed to market risk in the event of nonperformance by counterparties to energy-related and interest rate derivative contracts. The Company's practice is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $1.4 billion for 2009, $1.0 billion for 2010, and $1.0 billion for 2011. Environmental expenditures included in these estimated amounts are $584 million, $131 million, and $59 million for 2009, 2010, and 2011, respectively. Also included over the next three years, the Company estimates spending $586 million on Plant Farley (including $341 million for nuclear fuel), $950 million on distribution facilities, and $387 million on transmission additions. See Note 7 to the financial statements under "Construction Program" for additional details.

The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. As a result of Nuclear Regulatory Commission requirements, the Company has external trust funds for nuclear decommissioning costs; however, the Company currently has no additional funding requirements. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition to the funds required for the Company's construction program, approximately $550 million will be required by the end of 2011 for maturities of long-term debt. The Company plans to continue, when economically feasible, to retire higher cost securities and replace these obligations with lower-cost capital if market conditions permit.

The Company has also established an external trust fund for postretirement benefits as ordered by the Alabama PSC. The cumulative effect of funding these items over a long period will diminish internally funded capital for other purposes and may require the Company to seek capital from other sources. For additional information, see Note 2 to the financial statements under "Postretirement Benefits."

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities, as well as the related interest, derivative obligations, preferred and preference stock dividends, leases, and other purchase commitments, are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2009	2010-2011	2012-2013	After 2013	Total
			(in millions)		
Long-term debt[a] –					
Principal	$ 250	$ 300	$ 750	$ 4,558	$ 5,858
Interest	291	549	499	4,351	5,690
Preferred and preference stock dividends[b]	39	79	79	-	197
Energy-related derivative obligations[c]	75	20	-	-	95
Operating leases	23	28	12	11	74
Purchase commitments[d] –					
Capital [e]	1,365	1,865	-	-	3,230
Limestone[f]	3	24	29	68	124
Coal	1,461	1,804	1,110	1,414	5,789
Nuclear fuel	48	82	76	10	216
Natural gas [g]	505	386	311	210	1,412
Purchased power	105	44	-	-	149
Long-term service agreements[h]	18	35	29	37	119
Postretirement benefits trust[i]	17	35	-	-	52
Total	$4,200	$5,251	$2,895	$10,659	$23,005

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2009, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Preferred and preference stock do not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 6 to the financial statements.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2008, 2007, and 2006 were $1.26 billion, $1.19 billion, and $1.10 billion, respectively.

(e) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures excluding those amounts related to contractual purchase commitments for nuclear fuel. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program.

(f) As part of the Company's program to reduce sulfur dioxide emissions from certain of its coal plants, the Company has begun construction of flue gas desulfurization projects and has entered into various long-term commitments for the procurement of limestone to be used in such equipment.

(g) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2008.

(h) Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts postretirement trust contributions over a three-year period. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time. Therefore, no amounts related to the pension trust are included in the table. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2008 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth and retail rates, storm damage cost recovery and repairs, fuel cost recovery and other rate actions, environmental regulations and expenditures, access to sources of capital, projections for postretirement benefit and nuclear decommissioning trust contributions, financing activities, completion of construction projects, filings with state and federal regulatory authorities, impacts of adoption of new accounting rules, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

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STATEMENTS OF INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Alabama Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Revenues:			
Retail revenues	**$4,862,281**	$4,406,956	$3,995,731
Wholesale revenues --			
Non-affiliates	**711,903**	627,047	634,552
Affiliates	**308,482**	144,089	216,028
Other revenues	**194,265**	181,901	168,417
Total operating revenues	**6,076,931**	5,359,993	5,014,728
Operating Expenses:			
Fuel	**2,184,310**	1,762,418	1,672,831
Purchased power --			
Non-affiliates	**178,807**	96,928	124,022
Affiliates	**359,202**	341,461	302,045
Other operations and maintenance	**1,258,888**	1,186,235	1,096,978
Depreciation and amortization	**520,449**	471,536	451,018
Taxes other than income taxes	**306,522**	286,579	258,135
Total operating expenses	**4,808,178**	4,145,157	3,905,029
Operating Income	**1,268,753**	1,214,836	1,109,699
Other Income and (Expense):			
Allowance for equity funds used during construction	**45,519**	35,425	18,253
Interest income	**19,394**	19,545	20,897
Interest expense, net of amounts capitalized	**(278,917)**	(273,737)	(252,282)
Other income (expense), net	**(31,514)**	(29,144)	(23,758)
Total other income and (expense)	**(245,518)**	(247,911)	(236,890)
Earnings Before Income Taxes	**1,023,235**	966,925	872,809
Income taxes	**367,813**	351,198	330,345
Net Income	**655,422**	615,727	542,464
Dividends on Preferred and Preference Stock	**39,463**	36,145	24,734
Net Income After Dividends on Preferred and Preference Stock	**$ 615,959**	$ 579,582	$ 517,730

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2008, 2007, and 2006

Alabama Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Activities:			
Net income	**$ 655,422**	$ 615,727	$ 542,464
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**599,767**	548,959	524,313
Deferred income taxes and investment tax credits, net	**126,538**	21,269	(27,562)
Allowance for equity funds used during construction	**(45,519)**	(35,425)	(18,253)
Pension, postretirement, and other employee benefits	**(26,530)**	(18,781)	(15,196)
Stock based compensation expense	**3,105**	4,900	4,848
Tax benefit of stock options	**685**	1,118	610
Other, net	**27,689**	(13,650)	29,564
Changes in certain current assets and liabilities --			
Receivables	**(31,693)**	(5,797)	(33,260)
Fossil fuel stock	**(134,212)**	(33,840)	(28,179)
Materials and supplies	**(17,723)**	(32,543)	(25,711)
Other current assets	**(1,494)**	22,354	38,645
Accounts payable	**(8,751)**	78,508	(49,725)
Accrued taxes	**36,957**	(17,248)	1,124
Accrued compensation	**(4,722)**	4,194	(6,157)
Other current liabilities	**(198)**	10,098	18,486
Net cash provided from operating activities	**1,179,321**	1,149,843	956,011
Investing Activities:			
Property additions	**(1,477,643)**	(1,157,186)	(933,306)
Investment in restricted cash from pollution control bonds	**(96,326)**	(97,775)	-
Distribution of restricted cash from pollution control bonds	**35,979**	78,043	-
Nuclear decommissioning trust fund purchases	**(300,503)**	(334,275)	(286,551)
Nuclear decommissioning trust fund sales	**299,636**	333,409	285,685
Cost of removal net of salvage	**(41,744)**	(48,932)	(40,834)
Other	**(19,143)**	(26,621)	(1,777)
Net cash used for investing activities	**(1,599,744)**	(1,253,337)	(976,783)
Financing Activities:			
Increase (decrease) in notes payable, net	**24,995**	(119,670)	(195,609)
Proceeds --			
Senior notes	**850,000**	850,000	950,000
Preferred and preference stock	**-**	200,000	150,000
Common stock issued to parent	**300,000**	229,000	120,000
Capital contributions	**21,272**	27,867	27,160
Gross excess tax benefit of stock options	**1,289**	2,556	1,291
Pollution control revenue bonds	**265,100**	265,500	-
Redemptions --			
Senior notes	**(410,000)**	(668,500)	(546,500)
Preferred stock	**(125,000)**	-	-
Pollution control revenue bonds	**(11,100)**	-	(2,950)
Other long-term debt	**-**	(103,093)	-
Payment of preferred and preference stock dividends	**(40,899)**	(31,380)	(24,318)
Payment of common stock dividends	**(491,300)**	(465,000)	(440,600)
Other	**(9,369)**	(25,709)	(24,635)
Net cash provided from financing activities	**374,988**	161,571	13,839
Net Change in Cash and Cash Equivalents	**(45,435)**	58,077	(6,933)
Cash and Cash Equivalents at Beginning of Year	**73,616**	15,539	22,472
Cash and Cash Equivalents at End of Year	**$ 28,181**	$ 73,616	$ 15,539
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $20,215, $17,961, and $7,930 capitalized, respectively)	**$258,918**	$248,289	$245,387
Income taxes (net of refunds)	**214,368**	340,951	345,803

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2008 and 2007
Alabama Power Company 2008 Annual Report

Assets	2008	2007
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 28,181**	$ 73,616
Restricted cash	**80,079**	19,732
Receivables --		
Customer accounts receivable	**350,409**	357,355
Unbilled revenues	**98,921**	95,278
Under recovered regulatory clause revenues	**153,899**	232,226
Other accounts and notes receivable	**44,645**	42,745
Affiliated companies	**70,612**	61,250
Accumulated provision for uncollectible accounts	**(8,882)**	(7,988)
Fossil fuel stock, at average cost	**322,089**	182,963
Materials and supplies, at average cost	**305,880**	287,994
Vacation pay	**52,577**	50,266
Prepaid expenses	**88,220**	72,952
Other	**87,740**	19,610
Total current assets	**1,674,370**	1,487,999
Property, Plant, and Equipment:		
In service	**17,635,129**	16,669,142
Less accumulated provision for depreciation	**6,259,720**	5,950,373
	11,375,409	10,718,769
Nuclear fuel, at amortized cost	**231,862**	137,146
Construction work in progress	**1,092,516**	928,182
Total property, plant, and equipment	**12,699,787**	11,784,097
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	**50,912**	48,664
Nuclear decommissioning trusts, at fair value	**403,966**	542,846
Other	**62,782**	31,146
Total other property and investments	**517,660**	622,656
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**362,596**	347,193
Prepaid pension costs	**166,334**	989,085
Deferred under recovered regulatory clause revenues	**180,874**	81,650
Other regulatory assets	**732,367**	224,792
Other	**202,018**	209,153
Total deferred charges and other assets	**1,644,189**	1,851,873
Total Assets	**$16,536,006**	$15,746,625

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2008 and 2007
Alabama Power Company 2008 Annual Report

Liabilities and Stockholder's Equity	2008	2007
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 250,079**	$ 535,152
Notes payable	**24,995**	-
Accounts payable --		
Affiliated	**178,708**	193,518
Other	**358,176**	308,177
Customer deposits	**77,205**	67,722
Accrued taxes --		
Income taxes	**18,299**	45,958
Other	**30,372**	29,198
Accrued interest	**56,375**	55,263
Accrued vacation pay	**44,217**	42,138
Accrued compensation	**91,856**	92,385
Liabilities from risk management activities	**83,873**	6,404
Other	**53,777**	48,927
Total current liabilities	**1,267,932**	1,424,842
Long-term Debt (See accompanying statements)	**5,604,791**	4,750,196
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**2,243,117**	2,065,264
Deferred credits related to income taxes	**90,083**	93,709
Accumulated deferred investment tax credits	**172,638**	180,578
Employee benefit obligations	**396,923**	349,974
Asset retirement obligations	**461,284**	505,794
Other cost of removal obligations	**634,792**	613,616
Other regulatory liabilities	**79,150**	637,040
Other	**45,859**	31,417
Total deferred credits and other liabilities	**4,123,846**	4,477,392
Total Liabilities	**10,996,569**	10,652,430
Preferred and Preference Stock (See accompanying statements)	**685,127**	683,512
Common Stockholder's Equity (See accompanying statements)	**4,854,310**	4,410,683
Total Liabilities and Stockholder's Equity	**$16,536,006**	$15,746,625
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION

At December 31, 2008 and 2007

Alabama Power Company 2008 Annual Report

	2008	2007	2008	2007
		(in thousands)	*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
5.5% due 2042	**$ 206,186**	$ 206,186		
Long-term notes payable --				
3.125% to 5.375% due 2008	**-**	410,000		
Floating rate (2.34% at 1/1/09) due 2009	**250,000**	250,000		
4.70% due 2010	**100,000**	100,000		
5.10% due 2011	**200,000**	200,000		
4.85% due 2012	**500,000**	200,000		
5.80% due 2013	**250,000**	-		
5.125% to 6.375% due 2016-2047	**3,275,000**	2,975,000		
Total long-term notes payable	**4,575,000**	4,135,000		
Other long-term debt --				
Pollution control revenue bonds:				
2.00% to 5.00% due 2030-2038	**500,500**	-		
Variable rates (0.92% to 1.83% at 1/1/09) due 2015-2036	**576,190**	822,690		
Total other long-term debt	**1,076,690**	822,690		
Capitalized lease obligations	**79**	231		
Unamortized debt premium (discount), net	**(3,085)**	(3,759)		
Total long-term debt (annual interest requirement -- $290.8 million)	**5,854,870**	5,160,348		
Less amount due within one year	**250,079**	410,152		
Long-term debt excluding amount due within one year	**5,604,791**	4,750,196	**50.3%**	48.3%

STATEMENTS OF CAPITALIZATION (continued)
At December 31, 2008 and 2007
Alabama Power Company 2008 Annual Report

	2008	2007	2008	2007
		(in thousands)	*(percent of total)*	
Preferred and Preference Stock:				
Cumulative preferred stock				
$100 par or stated value -- 4.20% to 4.92%				
Authorized - 3,850,000 shares				
Outstanding - 475,115 shares	**47,610**	47,610		
$1 par value -- 5.20% to 5.83%				
Authorized - 27,500,000 shares				
Outstanding - 12,000,000 shares: $25 stated value	**294,105**	294,105		
Outstanding - 2008: 0 shares	**-**	123,331		
2007: 1,250 shares: $100,000 stated capital				
Preference stock				
Authorized - 40,000,000 shares				
Outstanding - $1 par value -- 5.63% to 6.50%				
- 14,000,000 shares				
(non-cumulative) $25 stated value	**343,412**	343,466		
Total preferred and preference stock				
(annual dividend requirement -- $39.5 million)	**685,127**	808,512		
Less amount due within one year	**-**	125,000		
Preferred and preference stock				
excluding amount due within one year	**685,127**	683,512	**6.1**	6.9
Common Stockholder's Equity:				
Common stock, par value $40 per share --				
Authorized - 2008: 40,000,000 shares				
- 2007: 25,000,000 shares				
Outstanding - 2008: 25,475,000 shares	**1,019,000**	719,000		
- 2007: 17,975,000 shares				
Paid-in capital	**2,091,462**	2,065,298		
Retained earnings	**1,753,797**	1,630,832		
Accumulated other comprehensive income (loss)	**(9,949)**	(4,447)		
Total common stockholder's equity	**4,854,310**	4,410,683	**43.6**	44.8
Total Capitalization	**$11,144,228**	$9,844,391	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2008, 2007, and 2006

Alabama Power Company 2008 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)		
Balance at December 31, 2005	$370,000	$1,995,056	$1,439,144	$(11,474)	$3,792,726
Net income after dividends on preferred stock	-	-	517,730	-	517,730
Issuance of common stock	120,000	-	-	-	120,000
Capital contributions from parent company	-	33,907	-	-	33,907
Other comprehensive income (loss)	-	-	-	(4,057)	(4,057)
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	12,610	12,610
Cash dividends on common stock	-	-	(440,600)	-	(440,600)
Other	-	-	(29)	-	(29)
Balance at December 31, 2006	490,000	2,028,963	1,516,245	(2,921)	4,032,287
Net income after dividends on preferred and preference stock	-	-	579,582	-	579,582
Issuance of common stock	229,000	-	-	-	229,000
Capital contributions from parent company	-	36,441	-	-	36,441
Other comprehensive income (loss)	-	-	-	(1,526)	(1,526)
Cash dividends on common stock	-	-	(465,000)	-	(465,000)
Other	-	(106)	5	-	(101)
Balance at December 31, 2007	**719,000**	**2,065,298**	**1,630,832**	**(4,447)**	**4,410,683**
Net income after dividends on preferred and preference stock	**-**	**-**	**615,959**	**-**	**615,959**
Issuance of common stock	**300,000**	**-**	**-**	**-**	**300,000**
Capital contributions from parent company	**-**	**26,164**	**-**	**-**	**26,164**
Other comprehensive income (loss)	-	-	-	**(5,502)**	**(5,502)**
Cash dividends on common stock	-	-	**(491,300)**	-	**(491,300)**
Other	-	-	**(1,694)**	-	**(1,694)**
Balance at December 31, 2008	**$1,019,000**	**$2,091,462**	**$1,753,797**	**$(9,949)**	**$4,854,310**

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Alabama Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Net income after dividends on preferred and preference stock	**$615,959**	$579,582	$517,730
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(4,297), $(1,226), and $155, respectively	**(7,068)**	(2,017)	255
Reclassification adjustment for amounts included in net income, net of tax of $952, $298, and $(3,696), respectively	**1,566**	491	(6,080)
Pension and other postretirement benefit plans:			
Change in additional minimum pension liability, net of tax of $-, $-, and $1,109, respectively	**-**	-	1,768
Total other comprehensive income (loss)	**(5,502)**	(1,526)	(4,057)
Comprehensive Income	**$610,457**	$578,056	$513,673

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Alabama Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – the Company, Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power). The Company provides electricity to retail customers within its traditional service area located within the State of Alabama and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets, and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses. The investments in synthetic fuels ended on December 31, 2007. Southern Nuclear operates and provides services to Southern Company's nuclear power plants, including the Company's Plant Farley.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Alabama Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Reclassifications

Certain prior years' data presented in the financial statements have been reclassified to conform with current year presentation. The statements of cash flows for the prior periods presented have been modified within the operating activities section to combine the amount of "Deferred revenues" and "Hedge settlements" into "Other, net." The statements of income for the prior periods presented have been modified within the operating expenses section to combine the line items "Other operations" and "Maintenance" into a single line item entitled "Other operations and maintenance." The balance sheet at December 31, 2007 was modified to present a separate line for "Liabilities for risk management activities" previously included in "Other." These reclassifications had no effect on total assets, cash flows, or net income.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $321 million, $299 million, and $266 million during 2008, 2007, and 2006, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which Southern Nuclear operates the Company's Plant Farley and provides the following nuclear-related services at cost: general executive and advisory services, general operations, management and

technical services, administrative services including procurement, accounting, statistical analysis, employee relations, and other services with respect to business and operations. Costs for these services amounted to $196 million, $182 million, and $162 million during 2008, 2007, and 2006, respectively.

The Company jointly owns Plant Greene County with Mississippi Power. The Company has an agreement with Mississippi Power under which the Company operates Plant Greene County, and Mississippi Power reimburses the Company for its proportionate share of non-fuel expenses which were $11.1 million in 2008, $9.8 million in 2007, and $8.6 million in 2006. See Note 4 for additional information.

Southern Company's 30% ownership interest in Alabama Fuel Products, LLC (AFP), which produced synthetic fuel was terminated in July 2006. The Company had an agreement with an indirect subsidiary of Southern Company that provided services for AFP. Under this agreement, the Company provided certain accounting functions, including processing and paying fuel transportation invoices, and the Company was reimbursed for its expenses. Amounts billed under this agreement totaled approximately $1.2 million, $58.1 million, and $56.5 million in 2008, 2007, and 2006, respectively. In addition, the Company purchased synthetic fuel from AFP for use at several of the Company's plants. Synthetic fuel purchases totaled $6.2 million, $462.1 million, and $446.6 million in 2008, 2007, and 2006, respectively. The synthetic fuel purchases and related party transactions were terminated as of December 31, 2007.

The Company had an agreement with Southern Power under which the Company operated and maintained Plant Harris at cost. On August 1, 2007, that agreement was terminated and replaced with a service agreement under which the Company provides to Southern Power specifically requested services. In 2008, 2007, and 2006, the Company billed Southern Power $0.9 million, $2.4 million, and $2.2 million, respectively, under these agreements. Under a power purchase agreement (PPA) with Southern Power, the Company's purchased power costs from Plant Harris in 2008, 2007, and 2006 totaled $63.2 million, $66.3 million, and $61.7 million, respectively. The Company also provides the fuel, at cost, associated with the PPA and the fuel cost recognized by the Company was $119.6 million in 2008, $108.1 million in 2007, and $77.8 million in 2006. Additionally, the Company recorded $8.3 million of prepaid capacity expenses included in other deferred charges and other assets in the balance sheets at December 31, 2008, 2007 and 2006. See Note 3 under "Retail Regulatory Matters" and Note 7 under "Purchased Power Commitments" for additional information.

Also, see Note 4 for information regarding the Company's ownership in and PPA with Southern Electric Generating Company (SEGCO).

In the second quarter, Southern Power sold a turbine rotor assembly to the Company for approximately $8.2 million. In October 2008, the Company also sold a rotor to Southern Power for approximately $6.3 million and sold a distance piece component to Gulf Power for approximately $0.3 million. In the fourth quarter, the Company purchased from SEGCO two 230kV transmission lines. The purchase price for the transmission line facilities was approximately $3.9 million. These affiliate transactions were made in accordance with FERC and Alabama PSC rules and guidelines.

The traditional operating companies, including the Company, and Southern Power jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2008	2007	Note
	(in millions)		
Deferred income tax charges	**$ 363**	$ 347	(a)
Loss on reacquired debt	**80**	87	(b)
Vacation pay	**53**	50	(c)
Under recovered regulatory clause revenues	**335**	314	(d)
Fuel-hedging (realized and unrealized) losses	**95**	6	(e)
Other assets	**7**	6	(d)
Asset retirement obligations	**18**	(150)	(a)
Other cost of removal obligations	**(635)**	(614)	(a)
Deferred income tax credits	**(90)**	(94)	(a)
Fuel-hedging (realized and unrealized) gains	**(4)**	(5)	(e)
Mine reclamation and remediation	**(14)**	(14)	(d)
Nuclear outage	**(8)**	2	(d)
Deferred purchased power	**(20)**	(20)	(d)
Natural disaster reserve (future storms)	**(33)**	(26)	(d)
Other liabilities	**(4)**	(3)	(d)
Overfunded retiree benefit plans	**-**	(423)	(f)
Underfunded retiree benefit plans	**614**	138	(f)
Total assets (liabilities), net	**$757**	$(399)	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over the remaining life of the original issue which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year. This includes both vacation and banked holiday pay.

(d) Recorded and recovered or amortized as approved or accepted by the Alabama PSC.

(e) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally does not exceed two years. Upon final settlement, actual costs incurred are recovered through the fuel cost recovery clauses.

(f) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS No. 71, the Company would be required to write off or reclassify to accumulated other comprehensive income related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract periods. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company continuously monitors the under/over recovered balances and files for revised rates as required or when management deems appropriate depending on the rate. See Note 3 under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

The Company has a diversified base of customers. No single customer comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than one percent of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction.

The Company's property, plant, and equipment consisted of the following at December 31:

	2008	2007
	(in millions)	
Generation	**$ 9,096**	$ 8,541
Transmission	**2,559**	2,435
Distribution	**4,827**	4,586
General	**1,141**	1,095
Plant acquisition adjustment	**12**	12
Total plant in service	**$17,635**	$16,669

The cost of replacements of property – exclusive of minor items of property – is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of nuclear refueling costs, which are recorded in accordance with specific Alabama PSC orders. The Company accrues estimated nuclear refueling costs in advance of the unit's next refueling outage. The refueling cycle is 18 months for each unit. During 2008, the Company accrued $39.4 million and paid $28.5 million for an outage at Plant Farley Unit 2. At December 31, 2008, the reserve balance totaled $8.7 million and is included in the balance sheet in other regulatory liabilities.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.2% in 2008 and 3.1% in 2007 and 2006. Depreciation studies are conducted periodically to update the composite rates and the information is provided to the Alabama PSC and approved by the FERC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Alabama PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facility, Plant Farley. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2008 was $404 million. In addition, the Company has retirement obligations related to various landfill sites and underground storage tanks, asbestos removal, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities and certain wireless communication towers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Alabama PSC, and are reflected in the balance sheets. See "Nuclear Decommissioning" for further information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2008	2007
	(in millions)	
Balance beginning of year	**$506**	$476
Liabilities incurred	**-**	-
Liabilities settled	**(2)**	(3)
Accretion	**31**	33
Cash flow revisions [(a)]	**(74)**	-
Balance end of year	**$461**	$506

(a) Updated based on results from 2008 Nuclear Decommissioning Study

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has an external trust fund (the Fund) to comply with the NRC's regulations. Use of the Fund is restricted to nuclear decommissioning activities and the Fund is managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Alabama PSC, as well as the Internal Revenue Service (IRS). The Fund is invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as of December 31, 2008 as trading securities pursuant to FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115).

On January 1, 2008, the Company adopted FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. The Company elected the fair value option only for investment securities held in the Fund. The Fund is included in the balance sheets at fair value, as disclosed in Note 10.

Management elected to continue to record the Fund at fair value because management believes that fair value best represents the nature of the Fund. Management has delegated day-to-day management of the investments in the Fund to unrelated third party managers with oversight by Company management. The managers of the Fund are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the investment return on the Fund investments. Because of the Company's inability to choose to hold securities that have experienced unrealized losses until recovery of their value, all unrealized losses incurred during 2006 and 2007, prior to the adoption of SFAS No. 159, were considered other-than-temporary impairments under SFAS No. 115.

The adoption of SFAS No. 159 had no impact on the results of operations, cash flows, or financial condition of the Company. For all periods presented, all gains and losses, whether realized, unrealized, or identified as other-than-temporary, have been and will continue to be recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or other comprehensive income. Fair value adjustments, realized gains, and other-than-temporary impairment losses are determined on a specific identification basis.

At December 31, 2008, investment securities in the Fund totaled $402.9 million consisting of equity securities of $256.7 million, debt securities of $135.3 million, and $10.9 million of other securities. These amounts exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

At December 31, 2007, investment securities in the Fund totaled $542.8 million consisting of equity securities of $385.4 million, debt securities of $140.2 million, and $17.2 million of other securities. Unrealized gains were $130.8 million for equity securities, $7.0 million debt securities, and $0.1 million for other securities. Other-than-temporary impairments were $(15.7) million for equity securities and $(3.5) million for debt securities.

Sales of the securities held in the Fund resulted in cash proceeds of $299.6 million, $333.4 million, and $285.7 million, in 2008, 2007, and 2006, respectively, all of which were re-invested. For 2008, fair value reductions, including reinvested interest and dividends, were $134.4 million, of which $107.6 million related to securities held in the Fund at December 31, 2008. Realized gains and other-than-temporary impairment losses were $34.6 million and $37.2 million, respectively, in 2007 and $22.0 million and $18.2 million, respectively, in 2006. While the investment securities held in the Fund are reported as trading securities from the perspective of SFAS No. 115, the Fund continues to be managed with a long-term focus. Accordingly, all purchases and sales within the Fund are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Alabama PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed a plan with the NRC designed to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC. At December 31, 2008, the accumulated provisions for decommissioning were as follows:

	(in millions)
External trust funds	$404
Internal reserves	26
Total	$430

Site study cost is the estimate to decommission the facility as of the site study year. The estimated costs of decommissioning based on the most current study performed in 2008 for Plant Farley was as follows:

Decommissioning periods:	
Beginning year	2037
Completion year	2065
	(in millions)
Site study costs:	
Radiated structures	$1,060
Non-radiated structures	72
Total	$1,132

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from the above estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the site study. Significant assumptions used to determine these costs for ratemaking were an inflation rate of 4.5% and a trust earnings rate of 7.0%.

Amounts previously contributed to the external trust fund are currently projected to be adequate to meet the decommissioning obligations. The Company will continue to provide site specific estimates of the decommissioning costs and related projections of funds in the external trust to the Alabama PSC and, if necessary, would seek the Alabama PSC's approval to address any changes in a manner consistent with the NRC and other applicable requirements. The Company continues to transfer internal reserves (less than $1 million annually) previously collected from customers prior to the establishment of the external trust.

Allowance for Funds Used During Construction (AFUDC)

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. The equity component of AFUDC is not included in calculating taxable income. All current construction costs are included in retail rates. The composite rate used to determine the amount of AFUDC was 9.2% in 2008, 9.4% in 2007, and 8.8% in 2006. AFUDC, net of income tax, as a percent of net income after dividends on preferred and preference stock was 9.4% in 2008, 8.0% in 2007, and 4.5% in 2006.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Natural Disaster Reserve

In accordance with an Alabama PSC order, the Company has established a natural disaster reserve (NDR) to cover the cost of uninsured damages from major storms to transmission and distribution facilities. The Company is authorized to collect a monthly NDR charge per account that consists of two components which began on January 1, 2006. The first component is intended to establish and maintain a reserve for future storms and is an on-going part of customer billing. This plan has a target reserve balance of $75 million that could be achieved within three years assuming the Company experiences no additional storms. The second component of the NDR charge is intended to allow recovery of any existing deferred hurricane related operations and maintenance costs and any future reserve deficits over a 24-month period. The Alabama PSC order gives the Company authority to have a negative NDR balance when costs of uninsured storm damage exceed any established NDR balance. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per account for non-residential customers and $5 per month per account for residential customers.

At December 31, 2008, the Company had accumulated a balance of $33.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities." In June 2007, the Company fully recovered its prior storm cost of $51.3 million resulting from Hurricanes Dennis and Katrina. As a result, customer rates decreased by this portion of the NDR charge effective July 1, 2007.

As revenue from the NDR charge is recognized, an equal amount of operations and maintenance expense related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income, but will increase annual cash flow.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Alabama PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (categorized in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Alabama PSC-approved fuel hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 6 under "Financial Instruments" for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2008.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

The Company's other financial instruments for which the carrying amounts did not equal fair values at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2008	**$5,855**	**$5,784**
2007	5,160	5,079

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2). See Note 10 for all other items recognized at fair value in the financial statements.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and prior to the adoption of SFAS No.158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158), the minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the investments in

these trusts are reflected as Other Investments, and the related loans from the trusts are included in Long-term Debt in the balance sheets.

Investments

The Company maintains an investment in a debt security that matures in 2018 and is classified as available-for-sale. This security is included in the balance sheets under Other Property and Investments-Other and totaled $0.4 million and $2.3 million at December 31, 2008 and 2007, respectively. Because the interest rate resets weekly, the carrying value approximates the fair market value.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2009. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds trusts to the extent required by the Alabama PSC and the FERC. For the year ending December 31, 2009, postretirement trust contributions are expected to total approximately $17.2 million.

The measurement date for plan assets and obligations for 2008 was December 31 while the measurement date for prior years was September 30. Pursuant to SFAS No. 158, the Company was required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ended December 31, 2008. As permitted, the Company adopted the measurement date provisions of SFAS No. 158 effective January 1, 2008 resulting in an increase in long-term liabilities of approximately $5 million and an increase in prepaid pension costs of approximately $11 million.

Pension Plans

The total accumulated benefit obligation for the pension plans was $1.4 billion in 2008 and $1.3 billion in 2007. Changes during the 15-month period ended December 31, 2008 and 12-month period ended September 30, 2007 in the projected benefit obligations and the fair value of plan assets were as follows:

	2008	2007
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$1,420**	$1,394
Service cost	**43**	35
Interest cost	**109**	82
Benefits paid	**(94)**	(70)
Plan amendments	**-**	10
Actuarial (gain) loss	**(18)**	(31)
Balance at end of year	**1,460**	1,420
Change in plan assets		
Fair value of plan assets at beginning of year	**2,318**	2,038
Actual return (loss) on plan assets	**(692)**	346
Employer contributions	**7**	4
Benefits paid	**(94)**	(70)
Fair value of plan assets at end of year	**1,539**	2,318
Funded status at end of year	**79**	898
Fourth quarter contributions	**-**	2
Prepaid pension asset, net	**$ 79**	$ 900

At December 31, 2008, the projected benefit obligations for the qualified and non-qualified pension plans were $1.4 billion and $87 million, respectively. All pension plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's pension plan assets as of the end of year, along with the targeted mix of assets, is presented below:

	Target	**2008**	2007
Domestic equity	36%	**34%**	38%
International equity	24	**23**	24
Fixed income	15	**14**	15
Real estate	15	**19**	16
Private equity	10	**10**	7
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's pension plans consist of:

	2008	2007
	(in millions)	
Prepaid pension asset	**$166**	$ 989
Other regulatory assets	**479**	43
Current liabilities, other	**(6)**	(5)
Other regulatory liabilities	**-**	(423)
Employee benefit obligations	**(81)**	(84)

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2008 and 2007 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2009:

	Prior Service Cost	**Net(Gain)Loss**
	(in millions)	
Balance at December 31, 2008:		
Regulatory assets	**$58**	**$ 421**
Regulatory liabilities	**-**	**-**
Total	**$58**	**$ 421**
Balance at December 31, 2007:		
Regulatory assets	$14	$ 29
Regulatory liabilities	56	(479)
Total	$70	$(450)
Estimated amortization in net periodic pension cost in 2009:		
Regulatory assets	$ 9	$ 1
Regulatory liabilities	-	-
Total	$ 9	$ 1

The changes in the balances of regulatory assets and regulatory liabilities related to the defined benefit pension plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in millions)	
Balance at December 31, 2006	$36	$(183)
Net (gain) loss	1	(232)
Change in prior service costs	10	-
Reclassification adjustments:		
Amortization of prior service costs	(2)	(8)
Amortization of net gain	(2)	-
Total reclassification adjustments	(4)	(8)
Total change	7	(240)
Balance at December 31, 2007	43	(423)
Net (gain) loss	441	433
Change in prior service costs	-	-
Reclassification adjustments:		
Amortization of prior service costs	(2)	(10)
Amortization of net gain	(3)	-
Total reclassification adjustments	(5)	(10)
Total change	436	423
Balance at December 31, 2008	$479	$ -

Components of net periodic pension cost (income) were as follows:

	2008	2007	2006
		(in millions)	
Service cost	**$ 35**	$ 35	$ 37
Interest cost	**87**	82	77
Expected return on plan assets	**(160)**	(146)	(139)
Recognized net (gain) loss	**2**	2	3
Net amortization	**10**	10	9
Net periodic pension (income)	**$ (26)**	$ (17)	$ (13)

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2008, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2009	$ 81
2010	84
2011	88
2012	92
2013	96
2014 to 2018	556

Other Postretirement Benefits

Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the accumulated postretirement benefit obligations (APBO) and in the fair value of plan assets were as follows:

	2008	2007
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 480**	$ 490
Service cost	**9**	7
Interest cost	**37**	28
Benefits paid	**(30)**	(23)
Actuarial (gain) loss	**(53)**	(24)
Retiree drug subsidy	**3**	2
Balance at end of year	**446**	480
Change in plan assets		
Fair value of plan assets at beginning of year	**297**	259
Actual return (loss) on plan assets	**(75)**	36
Employer contributions	**57**	23
Benefits paid	**(27)**	(21)
Fair value of plan assets at end of year	**252**	297
Funded status at end of year	**(194)**	(183)
Fourth quarter contributions	**-**	28
Accrued liability	**$(194)**	$(155)

Other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of year, along with the targeted mix of assets, is presented below:

	Target	2008	2007
Domestic equity	49%	**31%**	46%
International equity	12	**13**	15
Fixed income	31	**46**	29
Real estate	5	**7**	7
Private equity	3	**3**	3
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of:

	2008	2007
	(in millions)	
Regulatory assets	**$ 135**	$ 95
Employee benefit obligations	**(194)**	(155)

Presented below are the amounts included in regulatory assets at December 31, 2008 and 2007, related to the other postretirement benefit plans that had not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	Net (Gain)Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2008:			
Regulatory asset	**$49**	**$71**	**$15**
Balance at December 31, 2007:			
Regulatory asset	$55	$20	$20
Estimated amortization as net periodic postretirement cost in 2009:			
Regulatory asset	$ 4	$ -	$ 4

The change in the balance of regulatory assets related to the other postretirement benefit plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2006	$147
Net gain	(41)
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	(4)
Amortization of prior service costs	(5)
Amortization of net gain	(2)
Total reclassification adjustments	(11)
Total change	(52)
Balance at December 31, 2007	95
Net loss	50
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	(5)
Amortization of prior service costs	(5)
Amortization of net gain	-
Total reclassification adjustments	(10)
Total change	40
Balance at December 31, 2008	$135

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2008	2007	2006
		(in millions)	
Service cost	**$ 7**	$ 7	$ 7
Interest cost	**29**	28	26
Expected return on plan assets	**(22)**	(19)	(17)
Net amortization	**9**	11	12
Net postretirement cost	**$ 23**	$ 27	$ 28

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2008, 2007, and 2006 by approximately $10.7 million, $10.7 million, and $11.1 million, respectively.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2009	$ 28	$ (3)	$ 25
2010	31	(3)	28
2011	33	(4)	29
2012	35	(4)	31
2013	36	(5)	31
2014 to 2018	196	(30)	166

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2005 for the 2006 plan year, using a discount rate of 5.50%.

	2008	2007	2006
Discount	**6.75%**	6.30%	6.00%
Annual salary increase	**3.75**	3.75	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.15% for 2009, decreasing gradually to 5.50% through the year 2015, and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2008 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$31	$33
Service and interest costs	2	2

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution up to 6% of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75% up to 6% of the employee's base salary. Total matching contributions made to the plan for 2008, 2007, and 2006 were $18 million, $17 million, and $14 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that it had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. Through subsequent amendments and other legal procedures, the EPA filed a separate action in January 2001 against the Company in the U.S. District Court for the Northern District of Alabama after the Company was dismissed from the original action. In this lawsuit, the EPA alleged that NSR violations occurred at five coal-fired generating facilities operated by the Company. The civil action requests penalties and injunctive relief, including an order requiring the installation of the best available control technology at the affected units.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between the Company and the EPA, resolving a portion of the Company's lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required the Company to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by the Company, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted the Company's motion for summary judgment and entered final judgment in favor of the Company on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Company's case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of the Company regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case and the ultimate outcome of this matter cannot be determined at this time.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company has received authority from the Alabama PSC to recover approved environmental compliance costs through a specific retail rate clause that is adjusted annually. See "Retail Regulatory Matters – Rate CNP" herein for additional information.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $3.9 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order

is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Intercompany Interchange Contract

The Company's generation fleet is operated under the Intercompany Interchange Contract (IIC), as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the traditional operating companies (including the Company), Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms and Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan did not have a material impact on the Company's financial statements. In November 2007, Southern Company notified the FERC that the plan had been implemented. On December 12, 2008, the FERC division of audits issued, for public comment, its final audit report pertaining to compliance implementation and related matters. No comments challenging the audit report's findings were submitted. A decision is now pending from the FERC.

Generation Interconnection Agreements

In November 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to two previously executed interconnection agreements with the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $11 million previously paid for interconnection facilities. No other similar complaints are pending with the FERC.

In January 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order required the modification of Tenaska's interconnection agreements, under the provisions of the order, the Company determined that no refund was payable to Tenaska. The Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of FERC's methodology for determining the amount of refunds. The requested rehearings were denied and the Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

Retail Regulatory Matters

The following retail ratemaking procedures will remain in effect until the Alabama PSC votes to modify or discontinue them.

Rate RSE

The Alabama PSC has adopted a Rate Stabilization and Equalization plan (Rate RSE) that provides for periodic annual adjustments based upon the Company's earned return on retail common equity. Retail rates remain unchanged when the retail return on common equity ranges between 13.0% and 14.5%. In October 2005, the Alabama PSC approved a revision to Rate RSE. Effective January 2007 and thereafter, Rate RSE adjustments are made based on forward-looking information for the applicable upcoming calendar year. Rate adjustments for any two-year period, when averaged together, cannot exceed 4.0% per year and any annual adjustment is limited to 5.0%. Prior to January 2007, annual adjustments were limited to 3.0%. Retail rates remain unchanged when the return on retail common equity is projected to be between 13.0% and 14.5%. If the Company's actual retail return on common equity is above the allowed equity return range, customer refunds will be required; however, there is no provision for additional customer billings should the actual retail return on common equity fall below the allowed equity return range. The Rate RSE increase for 2008 was 3.24% or $147 million annually and was effective in January 2008.

On October 7, 2008, the Alabama PSC approved a corrective rate package primarily providing for adjustments associated with customer charges to certain existing rate structures. This package, effective in January 2009, is expected to generate additional annual revenues of approximately $168 million. The Company agreed to a moratorium on any increase in rates in 2009 under Rate RSE. On December 1, 2008, the Company made its submission of projected data for calendar year 2009.

Rate CNP

The Company's retail rates, approved by the Alabama PSC, provide for adjustments to recognize the placing of new generating facilities into retail service and the recovery of retail costs associated with certificated PPAs under a Rate Certificated New Plant (Rate CNP). In April 2006, an annual adjustment to Rate CNP increased retail rates by approximately 0.5% or $19 million annually. There was no rate adjustment associated with the annual true-up adjustment in April 2007 and 2008. There will be no adjustment to the current Rate CNP to recover certificated PPA costs in April 2009.

Rate CNP also allows for the recovery of the Company's retail costs associated with environmental laws, regulations, or other such mandates. The rate mechanism is based on forward looking information and provides for the recovery of these costs pursuant to a factor that is calculated annually. Environmental costs to be recovered include operations and maintenance expenses, depreciation, and a return on invested capital. Retail rates increased due to environmental costs approximately 1.2% in January 2006, 0.6% in January 2007, and 2.4% in January 2008. On October 7, 2008, the Company agreed to defer collection during 2009 of any increase in rates under the portion of Rate CNP, which permits recovery of costs associated with environmental laws and regulations until 2010. The deferral of the retail rate adjustments will have an immaterial impact on annual cash flows, and will have no significant effect on the Company's revenues or net income. On December 1, 2008, the Company made its submission of projected data for calendar year 2009.

Fuel Cost Recovery

The Company has established fuel cost recovery rates under an energy cost recovery clause (Rate ECR) approved by the Alabama PSC. Rates are based on an estimate of future energy costs and the current over or under recovered balance. The Company, along with the Alabama PSC, will continue to monitor the under recovered fuel cost balance to determine whether an additional adjustment to billing rates is required.

In June 2007, the Alabama PSC ordered the Company to increase its Rate ECR factor to 3.100 cents per kilowatt-hour (KWH) effective with billings beginning July 2007 for the 30-month period ending December 2009. The previous rate of 2.400 cents per KWH had been in effect since January 2006. This increase was intended to permit recovery of energy costs based on an estimate of future energy cost, as well as the collection of the existing under recovered energy cost by the end of 2009. During the recovery period, the Company was allowed to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation. In the event the application of this increased Rate ECR factor results in an over recovered position during this period, the Company would pay interest on any such over recovered balance at the same rate used to derive the carrying cost.

On October 7, 2008, the Alabama PSC approved an increase in the Company's Rate ECR factor to 3.983 cents per KWH for a 24-month period beginning with October 9, 2008 billings. Thereafter, the Rate ECR factor is 5.910 cents per KWH, absent a contrary order by the Alabama PSC. The previous rate of 3.100 cents per KWH had been in effect since July 2007. Rate ECR revenues, as recorded on the financial statements, are adjusted for the difference in actual recoverable costs and amounts billed in current regulated rates. During the 24-month period, the Company will be allowed to continue to include a carrying charge associated with the under recovered fuel costs in the fuel expense calculation. In the event the application of this increased Rate ECR factor results in an over recovered position during this period, the Company will pay interest on any such over recovered balance at the same rate used to derive the carrying cost.

The Company's under recovered fuel costs as of December 31, 2008 totaled $305.8 million as compared to $279.8 million at December 31, 2007. As a result of the Alabama PSC orders, the Company classified $180.9 million and $81.7 million of the under recovered regulatory clause revenues as deferred charges and other assets in the balance sheets as of December 31, 2008 and December 31, 2007, respectively. This classification is based on an estimate which includes such factors as weather, generation availability, energy demand, and the price of energy. A change in any of these factors could have a material impact on the timing of the recovery of the under recovered fuel costs.

Natural Disaster Cost Recovery

Based on an order by the Alabama PSC, the Company maintains a reserve for operations and maintenance expenses to cover the cost of damages from major storms to its transmission and distribution facilities.

In December 2005, the Alabama PSC approved a request by the Company to replenish the depleted NDR due to the hurricanes in 2005 and allow for recovery of future natural disaster costs. The Alabama PSC order gives the Company authority to record a deficit balance in the NDR when costs of uninsured storm damage exceed any established reserve balance. The order also approved a separate monthly NDR charge consisting of two components which began in January 2006. The first component is intended to establish and maintain a target reserve balance of $75 million for future storms and is an on-going part of customer billing. The Company currently expects that the target reserve balance could be achieved within three years. The second component of the NDR charge is intended to allow recovery of the existing deferred hurricane related operations and maintenance costs and any future reserve deficits over a 24-month period. Absent further Alabama PSC approval, the maximum total NDR charge consisting of both components is $10 per month per non-residential customer account and $5 per month per residential customer account.

At December 31, 2008, the Company had an accumulated balance of $33.2 million in the target reserve for future storms, which is included in the balance sheets under "Other Regulatory Liabilities." In June 2007, the Company fully recovered its storm cost of $51.3 million resulting from previous hurricanes. As a result, customer rates decreased by this portion of the NDR charge effective in July 2007.

As revenue from the NDR charge is recognized, an equal amount of operations and maintenance expense related to the NDR will also be recognized. As a result, this increase in revenue and expense will not have an impact on net income, but will increase annual cash flow.

Nuclear Fuel Disposal Costs

The Company has a contract with the United States, acting through the U.S. Department of Energy (DOE) that provides for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contract, and the Company is pursuing legal remedies against the government for breach of contract.

In July 2007, the U.S. Court of Federal Claims awarded the Company approximately $17 million, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plant Farley from 1998 through 2004. In July 2007, the government filed a motion for reconsideration, which was denied in November 2007. On January 2, 2008, the government filed an appeal, and on February 29, 2008, filed a motion to stay the appeal. On April 1, 2008, the court granted the government's motion to stay the appeal pending the court's decisions in three other similar cases already on appeal. Those cases were decided in August 2008. Based on the rulings in those cases, the appeal is expected to proceed in first quarter 2009.

On April 3, 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. On October 31, 2008, the court denied a similar request by the government to stay this proceeding. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2008 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on net income is expected as any damage amounts collected from the government are expected to be returned to customers.

An on-site dry spent fuel storage facility at Plant Farley is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Georgia Power own equally all of the outstanding capital stock of SEGCO, which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of these units is sold equally to the Company and Georgia Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, interest expense, and a return on equity, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two years' notice. The

Company's share of purchased power totaled $124 million in 2008, $105 million in 2007, and $95 million in 2006, and is included in "Purchased power from affiliates" in the statements of income. The Company accounts for SEGCO using the equity method.

In addition, the Company has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $24.5 million principal amount of pollution control revenue bonds are outstanding. Also, the Company has guaranteed $50 million principal amount of unsecured senior notes issued by SEGCO for general corporate purposes. Georgia Power has agreed to reimburse the Company for the pro rata portion of such obligations corresponding to its then proportionate ownership of stock of SEGCO if the Company is called upon to make such payment under its guaranty.

At December 31, 2008, the capitalization of SEGCO consisted of $68 million of equity and $74 million of long-term debt on which the annual interest requirement is $3.2 million. SEGCO paid dividends totaling $7.8 million in 2008, $2.6 million in 2007, and $8.5 million in 2006, of which one-half of each was paid to the Company. In addition, the Company recognizes 50% of SEGCO's net income.

In addition to the Company's ownership of SEGCO, the Company's percentage ownership and investment in jointly-owned coal-fired generating plants at December 31, 2008 is as follows:

Facility	Total Megawatt Capacity	Company Ownership	Company Investment	Accumulated Depreciation
			(in millions)	
Greene County	**500**	**60.00% (1)**	**$130**	**$68**
Plant Miller Units 1 and 2	**1,320**	**91.84% (2)**	**986**	**425**

(1) Jointly owned with an affiliate, Mississippi Power.
(2) Jointly owned with PowerSouth.

At December 31, 2008, the Company's Plant Miller portion of construction work in progress was $174.4 million.

The Company has contracted to operate and maintain the jointly owned facilities as agent for their co-owners. The Company's proportionate share of its plant operating expenses is included in operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined income tax returns for the State of Georgia, State of Mississippi, and the State of Alabama. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2008	2007	2006
		(in millions)	
Federal –			
Current	**$198**	$287	$302
Deferred	**121**	17	(25)
	319	304	277
State –			
Current	**43**	43	56
Deferred	**6**	4	(3)
	49	47	53
Total	**$368**	$351	$330

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2008	2007
	(in millions)	
Deferred tax liabilities:		
Accelerated depreciation	**$1,908**	$1,766
Property basis differences	**343**	341
Premium on reacquired debt	**33**	36
Pension and other benefits	**175**	340
Fuel clause under recovered	**140**	128
Regulatory assets associated with employee benefit obligations	**286**	90
Asset retirement obligations	**-**	27
Regulatory assets associated with asset retirement obligations	**199**	187
Other	**67**	60
Total	**3,151**	2,975
Deferred tax assets:		
Federal effect of state deferred taxes	**126**	121
State effect of federal deferred taxes	**104**	96
Unbilled revenue	**34**	31
Storm reserve	**4**	3
Pension and other benefits	**330**	126
Other comprehensive losses	**13**	10
Regulatory liabilities associated with employee benefit obligations	**-**	178
Asset retirement obligations	**199**	214
Other	**82**	88
Total	**892**	867
Total deferred tax liabilities, net	**2,259**	2,108
Portion included in current (liabilities) assets, net	**(16)**	(43)
Accumulated deferred income taxes in the balance sheets	**$2,243**	$2,065

At December 31, 2008, the Company's tax-related regulatory assets and liabilities were $363 million and $90 million, respectively. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $8.0 million in 2008, 2007, and 2006. At December 31, 2008, all investment tax credits available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2008	2007	2006
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**3.1**	3.2	4.0
Non-deductible book depreciation	**0.9**	0.9	1.0
Differences in prior years' deferred and current tax rates	**(0.1)**	(0.2)	(0.3)
AFUDC-equity	**(1.6)**	(1.3)	(0.7)
Production activities deduction	**(0.5)**	(0.6)	(0.2)
Other	**(0.8)**	(0.7)	(0.9)
Effective income tax rate	**36.0%**	36.3%	37.9%

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U. S. production activities as defined in Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The increase from 3% in 2006 to 6% in 2007 was one of several factors that increased the Company's 2007 deduction by $7.8 million over the 2006 deduction. The resulting additional tax benefit was approximately $3 million. The IRS has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction for all previous years to conform to the agreement which resulted in a decrease in the 2008 deduction when compared to the 2007 deduction. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements.

Unrecognized Tax Benefits

FIN 48 requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties. For 2008, the total amount of unrecognized tax benefits decreased by $1.8 million, resulting in a balance of $3.0 million as of December 31, 2008.

Changes during the year in unrecognized tax benefits were as follows:

	2008	2007
	(in millions)	
Unrecognized tax benefits at beginning of year	**$4.8**	**$1.2**
Tax positions from current periods	**0.8**	**1.5**
Tax positions from prior periods	**(1.4)**	**2.1**
Reductions due to settlements	**(1.2)**	**-**
Reductions due to expired statute of limitations	**-**	**-**
Balance at end of year	**$3.0**	**$4.8**

The reduction due to settlements relates to the agreement with the IRS regarding the production activities deduction methodology. See "Effective Tax Rate" above for additional information.

Impact on the Company's effective tax rate, if recognized, is as follows:

	2008	2007	Change
		(in millions)	
Tax positions impacting the effective tax rate	**$3.0**	**$4.8**	**$(1.8)**
Tax positions not impacting the effective tax rate	**-**	**-**	**-**
Balance of unrecognized tax benefits	**$3.0**	**$4.8**	**$(1.8)**

Accrued interest for unrecognized tax benefits:

	2008	2007
	(in millions)	
Interest accrued at beginning of year	**$0.4**	**$ -**
Interest reclassified due to settlements	**(0.3)**	**-**
Interest accrued during the year	**0.2**	**0.4**
Balance at end of year	**$0.3**	**$0.4**

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized benefit with respect to a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The possible conclusion or settlement of federal or state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2004. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2002.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million, which constitute substantially all assets of these trusts and are reflected in the balance sheets as Long-term Debt Payable. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2008, preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

At December 31, 2008, the Company had scheduled maturities and redemptions of senior notes due within one year totaling $250 million. At December 31, 2007, the Company had scheduled maturities and redemptions of senior notes, and preferred stock due within one year totaling $535 million.

Maturities of senior notes through 2013 applicable to total long-term debt are as follows: $250 million in 2009; $100 million in 2010; $200 million in 2011; $500 million in 2012; and $250 million in 2013.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds or installment purchases of solid waste disposal facilities financed by funds derived from sales by public authorities of revenue bonds. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company incurred obligations related to the issuance of $254 million of pollution control revenue bonds in 2008. Proceeds from certain issuances are restricted until expenditures are incurred. During 2008, the Company was required to purchase a total of approximately $11 million of variable rate pollution control revenue bonds that were tendered by investors, all of which were subsequently remarketed.

Also, during 2008, the Company entered into $330 million notional amount of interest rate swaps related to variable rate pollution control revenue bonds to hedge changes in interest rate for the period February 2008 through February 2010. The weighted average fixed payment rate on these hedges is 2.49% and the Company now has a total of $576 million of such hedges in place, with an overall weighted average fixed payment rate of 2.69%.

Senior Notes

The Company issued a total of $850 million of unsecured senior notes in 2008. The proceeds of these issuances were used to repay short-term indebtedness and for other general corporate purposes.

At December 31, 2008 and 2007, the Company had $4.6 billion and $4.1 billion, respectively, of senior notes outstanding. These senior notes are subordinate to all secured debt of the Company which amounted to approximately $153 million at December 31, 2008.

Preference and Common Stock

In 2008, the Company issued no new shares of preference stock. The Company issued 7.5 million new shares of common stock to Southern Company at $40.00 per share and realized proceeds of $300 million. The proceeds of these issuances were used for general corporate purposes.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized and outstanding. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preferred stock, Class A preferred stock, and preference stock are subject to redemption at the option of the Company on or after a specified date (typically 5 or 10 years after the date of issuance).

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

The Company has granted liens on certain property in connection with the issuance of certain series of pollution control revenue bonds with an outstanding principal amount of $153 million, as of December 31, 2008.

Bank Credit Arrangements

The Company maintains committed lines of credit in the amount of $1.3 billion (including $582 million of such lines which are dedicated to funding purchase obligations relating to variable rate pollution control revenue bonds), of which $466 million will expire at various times during 2009. $379 million of the credit facilities expiring in 2009 allow for the execution of one-year term loans. $765 million of credit facilities expire in 2012.

Most of the credit arrangements require payment of a commitment fee based on the unused portion of the commitment or the maintenance of compensating balances with the banks. Commitment fees average less than one-fourth of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

Most of the Company's credit arrangements with banks have covenants that limit the Company's debt to 65% of total capitalization, as defined in the arrangements. For purposes of calculating these covenants, long-term notes payable to affiliated trusts are excluded from debt but included in capitalization. Exceeding this debt level would result in a default under the credit arrangements. At December 31, 2008, the Company was in compliance with the debt limit covenants. In addition, the credit arrangements typically contain cross default provisions that would be triggered if the Company defaulted on other indebtedness (including guarantee obligations) above a specified threshold. None of the arrangements contain material adverse change clauses at the time of borrowings.

The Company borrows through commercial paper programs that have the liquidity support of committed bank credit arrangements. In addition, the Company borrows from time to time through uncommitted credit arrangements. As of December 31, 2008, the Company had $25 million of commercial paper outstanding. As of December 31, 2007, the Company had no commercial paper outstanding. During 2008 and 2007, the peak amount outstanding for short-term borrowings was $301 million and $214 million, respectively. The average amount outstanding in 2008 and 2007 was $40 million and $36 million, respectively. The average annual interest rate on short-term borrowings in 2008 was 2.31% and in 2007 was 5.34%. Short-term borrowings are included in notes payable in the balance sheets.

At December 31, 2008, the Company had regulatory approval to have outstanding up to $2.0 billion of short-term borrowings.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages a fuel-hedging program implemented per the guidelines of the Alabama PSC. The Company also enters into hedges of forward electricity sales.

At December 31, 2008, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

	2008	2007
	(in millions)	
Regulatory hedges	$(91.9)	$(0.7)
Cash flow hedges	-	0.5
Non-accounting hedges	-	(0.2)
Total fair value	$(91.9)	$(0.4)

Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging program, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expenses as they are recovered through the fuel cost recovery clauses. Gains and losses on energy-related derivatives designated as cash flow hedges are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transactions. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred. There was no material ineffectiveness recorded in earnings for any period presented. The Company has energy-related hedges in place up to and including 2012.

The Company also enters into derivatives to hedge exposure to changes in interest rates. Derivatives related to variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings for any period presented.

At December 31, 2008, the Company had $576 million notional amount of interest rate derivatives outstanding that related to variable rate tax exempt debt, with net fair value losses of approximately $11 million as follows:

Notional Amount	Variable Rate Received	Weighted Average Fixed Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2008
				(in millions)
$576 million	SIFMA Index	2.69%*	February 2010	$(11)

* Hedged using the Securities Industry and Financial Markets Association Municipal Swap Index (SIFMA), (formerly the Bond Market Association/PSA Municipal Swap Index)

The fair value gain or loss for cash flow hedges are recorded in other comprehensive income and are reclassified into earnings at the same time the hedged items affect earnings. In 2007 and 2006, the Company settled gains/(losses) of $(6) million, and $18 million, respectively, upon termination of certain interest derivatives at the same time it issued debt and did not incur any such settlement gains/(losses) in 2008. The effective portions of these gains/(losses) have been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative, which approximates to the related underlying debt.

For the years 2008, 2007, and 2006, approximately $(3) million, $(1) million, and $10 million, respectively, of pre-tax gains/(losses) were reclassified from other comprehensive income to interest expense. For 2009, pre-tax losses of approximately $8 million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2010 and has deferred realized gains/(losses) that are being amortized through 2035.

All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. See Note 10 for additional information.

7. COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, currently estimated to total $1.4 billion in 2009, $1.0 billion in 2010, and $1.0 billion in 2011. These amounts include $48 million, $37 million, and $45 million in 2009, 2010, and 2011, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included under "Fuel Commitments." The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates

because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; Alabama PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program. The Company has no generating plants under construction. Construction of new transmission and distribution facilities and capital improvements, including those needed to meet environmental standards for existing generation, transmission, and distribution facilities, will continue.

Long-Term Service Agreements

The Company has entered into Long-Term Service Agreements (LTSAs) with General Electric (GE) for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. The LTSAs provide that GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in each contract.

In general, these LTSAs are in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the respective units. Total remaining payments to GE under these agreements for facilities owned are currently estimated at $119 million over the remaining life of the agreements, which are currently estimated to range up to 8 years. However, the LTSAs contain various cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any planned maintenance are recorded as either prepayments or other deferred charges and assets in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has begun construction of flue gas desulfurization projects and has entered into various long-term commitments for the procurement of limestone to be used in such equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 3.0 million tons equating to approximately $124 million through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $3 million in 2009, $10 million in 2010, $14 million in 2011, $14 million in 2012, and $15 million in 2013.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2008. Total estimated minimum long-term commitments at December 31, 2008 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2009	$ 505	$1,461	$ 48
2010	266	996	37
2011	120	808	45
2012	154	636	44
2013	157	474	32
2014 and thereafter	210	1,414	10
Total commitments	$1,412	$5,789	$216

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense totaled $70 million in 2008, $65 million in 2007, and $66 million in 2006.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Purchased Power Commitments

The Company has entered into various long-term commitments for the purchase of electricity. Total estimated minimum long-term obligations at December 31, 2008 were as follows:

	Commitments		
	Affiliated	Non-Affiliated	Total
	(in millions)		
2009	$61	$44	$105
2010	17	24	41
2011	-	3	3
2012	-	-	-
2013	-	-	-
2014 and thereafter	-	-	-
Total commitments	$78	$71	$149

Operating Leases

The Company has entered into rental agreements for coal rail cars, vehicles, and other equipment with various terms and expiration dates. These expenses totaled $26.1 million in 2008, $27.7 million in 2007, and $30.3 million in 2006. Of these amounts, $19.2 million, $20.5 million, and $21.5 million for 2008, 2007, and 2006, respectively, relate to the rail car leases and are recoverable through the Company's Rate ECR. At December 31, 2008, estimated minimum rental commitments for non-cancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Vehicles & Other	Total
		(in millions)	
2009	$17	$6	$23
2010	13	6	19
2011	5	4	9
2012	5	2	7
2013	4	1	5
2014 and thereafter	11	-	11
Total	$55	$19	$74

Subsequent to December 31, 2008, the Company entered into rental agreements for coal rail cars resulting in the minimum lease commitments above increasing by $3 million in 2009, $4 million in 2010, $2 million in 2011, and $1 million each in years 2012 and 2013.

In addition to the rental commitments above, the Company has potential obligations upon expiration of certain leases with respect to the residual value of the leased property. These leases expire in 2010 and 2013, and the Company's maximum obligations are $61.2 million and $18.6 million, respectively. At the termination of the leases, at the Company's option, the Company may negotiate an extension, exercise its purchase option, or the property can be sold to a third party. The Company expects that the fair market value of the leased property would substantially eliminate the Company's payments under the residual value obligations.

Guarantees

At December 31, 2008, the Company had outstanding guarantees related to SEGCO's purchase of certain pollution control facilities and issuance of senior notes, as discussed in Note 4, and to certain residual values of leased assets as described above in "Operating Leases."

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2008, there were 1,267 current and former employees of the Company participating in the stock option plan and there were 33.2 million shares of common stock remaining available for awards under this plan. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement, the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted in 2008, 2007, and 2006 were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2008	2007	2006
Expected volatility	**13.1%**	14.8%	16.9%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.8%**	4.6%	4.6%
Dividend yield	**4.5%**	4.3%	4.4%
Weighted average grant-date fair value	**$2.37**	$4.12	$4.15

The Company's activity in the stock option plan for 2008 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2007	6,186,430	$30.50
Granted	1,148,493	35.78
Exercised	(522,381)	27.68
Cancelled	(3,346)	32.31
Outstanding at December 31, 2008	**6,809,196**	$31.61
Exercisable at December 31, 2008	**4,610,589**	$29.65

The number of stock options vested and expected to vest in the future, as of December 31, 2008 was not significantly different from the number of stock options outstanding at December 31, 2008 as stated above. As of December 31, 2008, the weighted average remaining contractual term for the options outstanding and options exercisable was 6.1 years and 5.0 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $36.7 million and $33.9 million, respectively.

As of December 31, 2008, there was $1.1 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 10 months.

For the years ended December 31, 2008, 2007 and 2006, total compensation cost for stock option awards recognized in income was $3.1 million, $4.9 million and $4.8 million, respectively, with the related tax benefit also recognized in income of $1.2 million, $1.9 million and $1.9 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007, and 2006 was $5.2 million, $9.7 million, and $4.9 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $2.0 million, $3.7 million, and $1.9 million, respectively, for the years ended December 31, 2008, 2007, and 2006.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at Plant Farley. The Act provides funds up to $12.5 billion for public liability claims that could arise from a single nuclear incident. Plant Farley is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company is $235 million per incident but not more than an aggregate of $35 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities.

Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL and has elected a 12-week waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $39 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12 month period is $3.2 billion plus such additional amounts NEIL, can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its bond trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

On January 1, 2008, the Company adopted FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value, and requires additional disclosures about fair value measurements. The criterion that is set forth in SFAS No. 157 is applicable to fair value measurement where it is permitted or required under other accounting pronouncements.

SFAS No. 157 defines fair value as the exit price, which is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement. As a

means to illustrate the inputs used, SFAS No. 157 establishes a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

The adoption of SFAS No. 157 has not resulted in any significant changes to the methodologies used for fair value measurement. Primarily all the changes in the fair value of assets and liabilities are recorded in other comprehensive income or regulatory assets and liabilities, and thus the impact on earnings is limited to derivatives that do not qualify for hedge accounting.

The fair value measurements performed on a recurring basis and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

At December 31, 2008:	Level 1	Level 2	Level 3	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 3.6	$ -	$ 3.6
Nuclear decommissioning trusts[(a)]	237.4	165.5	-	402.9
Cash equivalents and restricted cash	80.1	-	-	80.1
Total fair value	$317.5	$169.1	$ -	$486.6
Liabilities:				
Energy-related derivatives	$ -	$ 95.5	$ -	$ 95.5
Interest rate derivatives	-	10.9	-	10.9
Total fair value	$ -	$106.4	$ -	$106.4

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

Energy-related derivatives and interest rate derivatives primarily consist of over-the-counter contracts. See Note 6 under "Financial Instruments" for additional information. The nuclear decommissioning trust funds are invested in a diversified mix of equity and fixed income securities. See Note 1 under "Nuclear Decommissioning" for additional information. The cash equivalents and restricted cash consist of securities with original maturities of 90 days or less. All of these financial instruments and investments are valued primarily using the market approach.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2008 and 2007 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2008	**$1,337**	**$274**	**$130**
June 2008	**1,470**	**319**	**153**
September 2008	**1,865**	**478**	**252**
December 2008	**1,405**	**198**	**81**
March 2007	$1,197	$255	$115
June 2007	1,336	311	147
September 2007	1,635	476	246
December 2007	1,192	173	72

The Company's business is influenced by seasonal weather conditions.

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SELECTED FINANCIAL AND OPERATING DATA 2004-2008

Alabama Power Company 2008 Annual Report

	2008	2007	2006	2005	2004
Operating Revenues (in thousands)	**$6,076,931**	$5,359,993	$5,014,728	$4,647,824	$4,235,991
Net Income after Dividends on Preferred and Preference Stock (in thousands)	**$615,959**	$579,582	$517,730	$507,895	$481,171
Cash Dividends on Common Stock (in thousands)	**$491,300**	$465,000	$440,600	$409,900	$437,300
Return on Average Common Equity (percent)	**13.30**	13.73	13.23	13.72	13.53
Total Assets (in thousands)	**$16,536,006**	$15,746,625	$14,655,290	$13,689,907	$12,781,525
Gross Property Additions (in thousands)	**$1,532,673**	$1,203,300	$960,759	$890,062	$786,298
Capitalization (in thousands):					
Common stock equity	**$4,854,310**	$4,410,683	$4,032,287	$3,792,726	$3,610,204
Preferred and preference stock	**685,127**	683,512	612,407	465,046	465,047
Long-term debt	**5,604,791**	4,750,196	4,148,185	3,869,465	4,164,536
Total (excluding amounts due within one year)	**$11,144,228**	$9,844,391	$8,792,879	$8,127,237	$8,239,787
Capitalization Ratios (percent):					
Common stock equity	**43.6**	44.8	45.9	46.7	43.8
Preferred and preference stock	**6.1**	6.9	7.0	5.7	5.6
Long-term debt	**50.3**	48.3	47.1	47.6	50.6
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	**-**	-	-	A1	A1
Standard and Poor's	**-**	-	-	A+	A
Fitch	**-**	-	-	AA-	AA-
Preferred Stock/ Preference Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A**	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**1,220,046**	1,207,883	1,194,696	1,184,406	1,170,814
Commercial	**211,119**	216,830	214,723	212,546	208,547
Industrial	**5,906**	5,849	5,750	5,492	5,260
Other	**775**	772	766	759	753
Total	**1,437,846**	1,431,334	1,415,935	1,403,203	1,385,374
Employees (year-end)	**6,997**	6,980	6,796	6,621	6,745

	2008	2007	2006	2005	2004
Operating Revenues (in thousands):					
Residential	**$1,997,603**	$1,833,563	$1,664,304	$1,476,211	$1,346,669
Commercial	**1,459,466**	1,313,642	1,172,436	1,062,341	980,771
Industrial	**1,381,100**	1,238,368	1,140,225	1,065,124	948,528
Other	**24,112**	21,383	18,766	17,745	16,860
Total retail	**4,862,281**	4,406,956	3,995,731	3,621,421	3,292,828
Wholesale - non-affiliates	**711,903**	627,047	634,552	551,408	483,839
Wholesale - affiliates	**308,482**	144,089	216,028	288,956	308,312
Total revenues from sales of electricity	**5,882,666**	5,178,092	4,846,311	4,461,785	4,084,979
Other revenues	**194,265**	181,901	168,417	186,039	151,012
Total	**$6,076,931**	$5,359,993	$5,014,728	$4,647,824	$4,235,991
Kilowatt-Hour Sales (in thousands):					
Residential	**18,379,801**	18,874,039	18,632,935	18,073,783	17,368,321
Commercial	**14,551,495**	14,761,243	14,355,091	14,061,650	13,822,926
Industrial	**22,074,616**	22,805,676	23,187,328	23,349,769	22,854,399
Other	**201,283**	200,874	199,445	198,715	198,253
Total retail	**55,207,195**	56,641,832	56,374,799	55,683,917	54,243,899
Sales for resale - non-affiliates	**15,203,960**	15,769,485	15,978,465	15,442,728	15,483,420
Sales for resale - affiliates	**5,256,130**	3,241,168	5,145,107	5,735,429	7,233,880
Total	**75,667,285**	75,652,485	77,498,371	76,862,074	76,961,199
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.87**	9.71	8.93	8.17	7.75
Commercial	**10.03**	8.90	8.17	7.55	7.10
Industrial	**6.26**	5.43	4.92	4.56	4.15
Total retail	**8.81**	7.78	7.09	6.50	6.07
Wholesale	**4.99**	4.06	4.03	3.97	3.49
Total sales	**7.77**	6.84	6.25	5.80	5.31
Residential Average Annual Kilowatt-Hour Use Per Customer	**15,162**	15,696	15,663	15,347	14,894
Residential Average Annual Revenue Per Customer	**$1,648**	$1,525	$1,399	$1,253	$1,155
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**12,222**	12,222	12,222	12,216	12,216
Maximum Peak-Hour Demand (megawatts):					
Winter	**10,747**	10,144	10,309	9,812	9,556
Summer	**11,518**	12,211	11,744	11,162	10,938
Annual Load Factor (percent)	**60.9**	59.4	61.8	63.2	63.2
Plant Availability (percent):					
Fossil-steam	**90.08**	88.2	89.6	90.5	87.8
Nuclear	**94.13**	87.5	93.3	92.9	88.7
Source of Energy Supply (percent):					
Coal	**58.5**	60.9	60.2	59.5	56.5
Nuclear	**17.8**	16.5	17.4	17.2	16.4
Hydro	**2.9**	1.8	3.8	5.6	5.6
Gas	**9.2**	8.7	7.6	6.8	8.9
Purchased power -					
From non-affiliates	**2.9**	1.8	2.1	3.8	5.4
From affiliates	**8.7**	10.3	8.9	7.1	7.2
Total	**100.0**	100.0	100.0	100.0	100.0

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GEORGIA POWER COMPANY

FINANCIAL SECTION

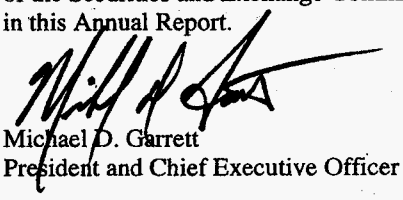
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Georgia Power Company 2008 Annual Report

The management of Georgia Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This Annual Report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.



Michael D. Garrett
President and Chief Executive Officer

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer, and Treasurer

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company

We have audited the accompanying balance sheets and statements of capitalization of Georgia Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2008 and 2007, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-199 to II-238) present fairly, in all material respects, the financial position of Georgia Power Company at December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

OVERVIEW

Business Activities

Georgia Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain energy sales in the midst of the current economic downturn, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, and fuel prices. In December 2007, the Company completed a major retail rate proceeding (2007 Retail Rate Plan) that enables the recovery of substantial capital investments to facilitate the continued reliability of the transmission and distribution networks, continued generation, and other investments as well as the recovery of increased operating costs. The 2007 Retail Rate Plan includes a tariff specifically for the recovery of costs related to environmental controls mandated by state and federal regulations. Appropriately balancing required costs and capital expenditures with customer prices will continue to challenge the Company for the foreseeable future. The Company is required to file a general rate case by July 1, 2010, which will determine whether the 2007 Retail Rate Plan should be continued, modified, or discontinued. The Company also received regulatory orders to increase its fuel cost recovery rate effective July 1, 2006, March 1, 2007, and June 1, 2008. The Company expects to file its next fuel cost recovery case on March 13, 2009.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to more than two million customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preferred and preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of fossil/hydro plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2008 fossil/hydro Peak Season EFOR of 0.84% was better than the target. The nuclear generating fleet also uses Peak Season EFOR as an indicator of availability and efficient generation fleet operations during the peak season. The 2008 nuclear Peak Season EFOR of 1.64% was also better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The 2008 performance was better than the target for these reliability measures. Net income after dividends on preferred and preference stock is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2008 results compared to its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2008 Target Performance	2008 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile in customer surveys
Peak Season EFOR – fossil/hydro	2.75% or less	0.84%
Peak Season EFOR – nuclear	2.00% or less	1.64%
Net Income	$900 million	$903 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2008 reflects the continued emphasis that management places on these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's 2008 net income after dividends on preferred and preference stock totaled $903 million representing a $66.8 million, or 8.0%, increase over 2007. The increase was primarily related to increased contributions from market-response rates for large commercial and industrial customers, higher retail base revenues resulting from the retail rate increase effective January 1, 2008, and increased allowance for equity funds used during construction. These increases were partially offset by increased depreciation and amortization resulting from more plant in service and changes to depreciation rates. The Company's 2007 earnings totaled $836 million representing a $48.9 million, or 6.2%, increase over 2006. Operating income increased slightly in 2007 primarily due to increased operating revenues from transmission and outdoor lighting and decreased property taxes, partially offset by higher non-fuel operating expenses. Net income increased primarily due to higher allowance for equity funds used during construction and lower income tax expenses resulting from the Company's donation of Tallulah Gorge to the State of Georgia, partially offset by higher financing costs. The Company's 2006 earnings totaled $787 million representing a $42.9 million, or 5.8%, increase over 2005. Operating income increased in 2006 due to higher base retail revenues and wholesale non-fuel revenues, partially offset by an increase in non-fuel operating expenses.

RESULTS OF OPERATIONS

A condensed income statement for the Company follows:

	Amount	Increase (Decrease) from Prior Year		
	2008	**2008**	2007	2006
		(in millions)		
Operating revenues	**$ 8,412**	**$ 840**	$ 326	$ 170
Fuel	**2,813**	**172**	408	296
Purchased power	**1,405**	**355**	(95)	(171)
Other operations and maintenance	**1,581**	**19**	1	(11)
Depreciation and amortization	**637**	**126**	13	(28)
Taxes other than income taxes	**316**	**25**	(8)	23
Total operating expenses	**6,752**	**697**	319	109
Operating income	**1,660**	**143**	7	61
Total other income and (expense)	**(252)**	**5**	18	(22)
Income taxes	**488**	**70**	(25)	(5)
Net income	**920**	**78**	50	44
Dividends on preferred and preference stock	**17**	**11**	1	1
Net income after dividends on preferred and preference stock	**$ 903**	**$ 67**	$ 49	$ 43

Operating Revenues

Operating revenues in 2008, 2007, and 2006, and the percent of change from the prior year were as follows:

	Amount		
	2008	2007	2006
		(in millions)	
Retail – prior year	**$ 6,498.0**	$ 6,205.6	$ 6,064.4
Estimated change in –			
Rates and pricing	**396.9**	(66.2)	(76.8)
Sales growth	**(20.9)**	46.5	76.6
Weather	**(37.7)**	17.7	7.5
Fuel cost recovery	**450.1**	294.4	133.9
Retail – current year	**7,286.4**	6,498.0	6,205.6
Wholesale revenues –			
Non-affiliates	**568.8**	537.9	551.7
Affiliates	**286.2**	277.9	252.6
Total wholesale revenues	**855.0**	815.8	804.3
Other operating revenues	**270.2**	257.9	235.7
Total operating revenues	**$ 8,411.6**	$ 7,571.7	$ 7,245.6
Percent change	**11.1%**	4.5%	2.4%

Retail base revenues of $4.1 billion in 2008 increased by $338.3 million, or 9.0%, from 2007 primarily due to an increase in revenues from market-response rates to large commercial and industrial customers, the retail rate increase effective January 1, 2008, and a 0.7% increase in retail customers. The increase was partially offset by a weak economy in the Southeast and more favorable weather impacts in 2007 than in 2008. Retail base revenues were $3.8 billion in 2007. There was not a material change in total retail base revenues compared to 2006, although industrial base revenues decreased $56.5 million, or 8.5%, primarily due to lower sales and a lower contribution from market-response rates for large commercial and industrial customers. This decrease was partially offset by a $31.8 million, or 2.1%, increase in residential base revenues as well as a $22.6 million, or 1.5%, increase in commercial base revenues primarily due to higher sales from favorable weather and customer growth of 1.2%. Retail base revenues of $3.8 billion in 2006 increased by $7 million, or 0.2%, from 2005 primarily due to customer growth of 1.9% and more favorable weather, partially offset by lower contributions from market-response rates to large commercial and industrial customers. See "Energy Sales" below for a discussion of changes in the volume of energy sold, including changes related to sales growth and weather.

Electric rates include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these fuel cost recovery provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Wholesale revenues from sales to non-affiliated utilities were as follows:

	2008	2007	2006
		(in millions)	
Unit power sales –			
Capacity	**$ 40**	$ 33	$ 33
Energy	**44**	33	38
Total	**84**	66	71
Other power sales –			
Capacity and other	**129**	158	165
Energy	**356**	314	316
Total	**485**	472	481
Total non-affiliated	**$569**	$538	$552

Wholesale revenues from sales to non-affiliates will vary depending on the market cost of available energy compared to the cost of the Company and Southern Company system-owned generation, demand for energy within the Southern Company service territory, and availability of Southern Company system generation.

Revenues from unit power sales increased $18.2 million, or 27.4%, in 2008 driven by higher fuel rates and an 8.2% increase in the kilowatt-hour (KWH) energy sales primarily related to sales by the Company's generating units when other Southern Company system units were unavailable. Revenues from unit power sales remained relatively constant in 2007 and 2006. Revenues from other non-affiliated sales increased $12.7 million, or 2.7%, in 2008, decreased $9.6 million, or 2.0%, in 2007, and increased $21.0 million, or 4.6%, in 2006. The increase in 2008 was primarily driven by the fuel component within non-affiliate wholesale prices which has increased with the effects of higher fuel and purchased power costs. This increase was partially offset by a 9.8% decrease in KWH energy sales and decreased contributions from the emissions allowance component of market-based wholesale rates. The decrease in 2007 was primarily due to a decrease in revenues from large territorial contracts resulting from lower emissions allowance prices. The increase in 2006 was due to a 0.6% increase in the demand for KWH energy sales due to a new contract with an electrical membership corporation that went into effect in April 2006.

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). In 2008, KWH energy sales to affiliated companies decreased 28.8% while revenues from sales to affiliates increased 3.0%. In 2007, KWH energy sales to affiliates decreased 5.0% while revenues from sales to affiliates increased 10.0%. The revenue increases in 2008 and 2007 were primarily due to the increased cost of fuel and other marginal generation components of the rates. In 2006, KWH energy sales to affiliates increased 8.5% due to higher demand. However, revenues from these sales decreased by 8.3% in 2006 due to reduced cost per KWH delivered. These transactions do not have a significant impact on earnings since this energy is generally sold at marginal cost.

Other operating revenues increased $12.3 million, or 4.8%, in 2008 primarily due to a $6.7 million increase in revenues from outdoor lighting resulting from a 15.8% increase in lighting customers and a $7.6 million increase in customer fees resulting from higher rates that went into effect in 2008, partially offset by a $2.2 million decrease in equipment rentals revenue. Other operating revenues increased $22.2 million, or 9.4%, in 2007 primarily due to an $11.6 million increase in transmission revenues due to the increased usage of the Company's transmission system by non-affiliated companies, a $7.9 million increase in revenues from outdoor lighting activities due to a 10% increase in the number of lighting customers, and a $4.0 million increase from customer fees. Other operating revenues increased $24.6 million, or 11.6%, in 2006 primarily due to increased revenues of $14.1 million related to work performed for the other owners of the integrated transmission system in the State of Georgia, higher customer fees of $4.6 million, and higher outdoor lighting revenues of $6.1 million.

Energy Sales

Changes in revenues are influenced heavily by the change in volume of energy sold from year to year. KWH sales for 2008 and the percent change by year were as follows:

	KWH	Percent Change		
	2008	2008	2007	2006
	(in billions)			
Residential	**26.4**	**(1.6)%**	2.4%	2.7%
Commercial	**33.0**	**0.0**	2.9	2.5
Industrial	**24.2**	**(5.2)**	(0.3)	(1.0)
Other	**0.7**	**(3.8)**	5.6	(10.5)
Total retail	**84.3**	**(2.1)**	1.8	1.4
Wholesale				
Non-affiliates	**9.8**	**(7.8)**	(1.0)	0.9
Affiliates	**3.7**	**(28.8)**	(5.0)	8.5
Total wholesale	**13.5**	**(14.7)**	(2.3)	3.4
Total energy sales	**97.8**	**(4.0)%**	1.1%	1.7%

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential KWH sales decreased 1.6% in 2008 compared to 2007 primarily due to less favorable weather, partially offset by a 0.7% increase in residential customers. Commercial KWH sales remained flat in 2008 compared to 2007 despite a 0.2% increase in commercial customers. Industrial KWH sales decreased 5.2% in 2008 over 2007 primarily due to reduced demand and closures within the textile and primary and fabricated metal industries, a result of the slowing economy that worsened during the fourth quarter 2008.

Residential KWH sales increased 2.4% in 2007 over 2006 due to favorable weather and a 1.3% increase in residential customers. Commercial KWH sales increased 2.9% in 2007 over 2006 primarily due to favorable weather and a 0.3% increase in commercial customers. Industrial KWH sales decreased 0.3% primarily due to reduced demand and closures within the textile industry; however, this was partially offset by a 2.9% increase in the number of industrial customers.

Residential KWH sales increased 2.7% in 2006 over 2005 due to customer growth of 1.9% and more favorable weather. Commercial KWH sales increased 2.5% in 2006 over 2005 due to customer growth of 2.0% and a reclassification of customers from industrial to commercial to be consistent with the rate structure approved by the Georgia Public Service Commission (PSC). Industrial KWH sales decreased 1.0% due to a 3.4% decrease in the number of customers as a result of this reclassification.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market. Details of the Company's electricity generated and purchased were as follows:

	2008	2007	2006
Total generation *(billions of KWHs)*	**80.8**	87.0	83.7
Total purchased power *(billions of KWHs)*	**21.3**	18.9	21.9
Sources of generation *(percent)* -			
Coal	**74**	75	75
Nuclear	**19**	18	18
Gas	**6**	7	6
Hydro	**1**	-	1
Cost of fuel, generated *(cents per net KWH)* -			
Coal	**3.44**	2.87	2.58
Nuclear	**0.51**	0.51	0.47
Gas	**6.90**	6.28	5.76
Average cost of fuel, generated *(cents per net KWH)*	**3.11**	2.68	2.39
Average cost of purchased power *(cents per net KWH)*	**8.10**	7.27	6.38

Fuel and purchased power expenses were $4.2 billion in 2008, an increase of $526.6 million, or 14.3%, above prior year costs. Substantially all of this increase was due to the higher average cost of fuel and purchased power.

Fuel and purchased power expenses were $3.7 billion in 2007, an increase of $312.9 million, or 9.3%, above prior year costs. This increase was driven by a $414.5 million increase in total energy costs due to the higher average cost of fuel and purchased power, partially offset by a $101.6 million reduction due to fewer KWHs purchased.

Fuel and purchased power expenses were $3.4 billion in 2006, an increase of $124.4 million, or 3.8%, above prior year costs. This increase was driven by a $146.1 million increase related to higher KWHs generated and purchased, partially offset by a $21.7 million decrease in the average cost of fuel and purchased power.

Over the last several years, coal prices have been influenced by a worldwide increase in demand from developing countries, as well as increases in mining and fuel transportation costs. In the first half of 2008, coal prices reached unprecedented high levels primarily due to increased demand following more moderate pricing in 2006 and 2007. Despite these fluctuations, fuel inventories have been adequate and fuel supply markets have been sufficient to meet expected fuel requirements. Demand for natural gas in the United States also increased in 2007 and the first half of 2008. However, natural gas supplies increased in the last half of 2008 as a result of increased production and higher storage levels due in part to weak industrial demand. Both coal and natural gas prices moderated in the second half of 2008 as the result of a recessionary economy. During 2008, uranium prices continued to moderate from the highs set during 2007. While worldwide uranium production levels appear to have increased slightly since 2007, secondary supplies and inventories were still required to meet worldwide reactor demand.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL — "PSC MATTERS — Fuel Cost Recovery" herein for additional information.

Other Operations and Maintenance Expenses

In 2008, other operations and maintenance expenses increased $19.2 million, or 1.2%, compared to 2007. The increase was primarily the result of a $14.7 million increase in the accrual for property damage approved under the 2007 Retail Rate Plan, a $14.6 million increase in scheduled outages and maintenance for fossil generating plants, and a $22.0 million increase related to meter reading, records and collections, and uncollectible account expenses. These increases were partially offset by decreases of $24.7 million related to the timing of transmission and distribution operations and maintenance and $7.4 million related to medical, pension, and other employee benefits.

In 2007, the change in other operations and maintenance expenses was immaterial compared to 2006.

In 2006, other operations and maintenance expenses decreased $11.0 million, or 0.7%, from the prior year. Maintenance for generating plants decreased $20.0 million in 2006 as a result of fewer scheduled outages than 2005, offset by an increase of $18.2 million for transmission and distribution expenses related to load dispatching and overhead line maintenance. Also contributing to the decrease were lower employee benefit expenses related to medical benefits and lower workers compensation expense of $23.2 million, partially offset by lower pension income of $13.7 million.

Depreciation and Amortization

Depreciation and amortization increased $125.8 million, or 24.6%, in 2008 compared to the prior year primarily due to an increase in plant in service related to completed transmission, distribution, and environmental projects, changes in depreciation rates effective January 1, 2008 approved under the 2007 Retail Rate Plan, and the expiration of amortization related to a regulatory liability for purchased power costs under the terms of the retail rate plan for the three years ended December 31, 2007 (2004 Retail Rate Plan).

Depreciation and amortization increased $12.4 million, or 2.5%, in 2007 compared to the prior year primarily due to a 3.4% increase in plant in service from the prior year. This increase was partially offset by a decrease in amortization of the regulatory liability for purchased power costs as described above.

Depreciation and amortization decreased $27.9 million, or 5.3%, in 2006 compared to the prior year due to the scheduled decrease in amortization related to the regulatory liability for purchased power costs as described above. This decrease was partially offset by a $15.9 million, or 3.2%, increase in depreciation in 2006 over 2005 due to an increase in plant in service. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Taxes Other Than Income Taxes

In 2008, taxes other than income taxes increased $25.1 million, or 8.6%, from the prior year primarily due to higher municipal franchise fees resulting from retail revenue increases during 2008. Taxes other than income taxes decreased $7.7 million, or 2.6%, in 2007 primarily due to the resolution of a dispute regarding property taxes in Monroe County, Georgia. Taxes other than income taxes increased $22.8 million, or 8.3%, in 2006 primarily due to higher property taxes of $13.3 million as a result of an increase in property values and higher municipal gross receipts taxes of $9.1 million as a result of increased retail operating revenues.

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) increased $27.1 million, or 39.8%, in 2008 primarily due to the increase in construction work in progress balances related to ongoing environmental and transmission projects as well as three combined cycle generating units at Plant McDonough. AFUDC increased $36.7 million, or 116.3%, in 2007 primarily due to the increase in the Company's construction work in progress balance related to ongoing transmission, distribution, and environmental projects. AFUDC remained relatively constant in 2006 when compared to 2005.

Interest Expense, Net of Amounts Capitalized

The increase in interest expense in 2008 was immaterial. Interest expense increased $25.5 million, or 8.0%, in 2007 primarily due to a 13.9% increase in long-term debt levels due to the issuance of additional senior notes and pollution control revenue bonds. Interest expense increased $22.5 million, or 7.6%, in 2006 primarily due to generally higher interest rates on variable rate debt and commercial paper, the issuance of additional senior notes, and higher average balances of short-term debt.

Other Income (Expense), Net

Other income (expense), net decreased $24.0 million, or 163.0%, in 2008 primarily due to a $12.9 million change in classification of revenues related to a residential pricing program to base retail revenues in 2008 as ordered by the Georgia PSC under the 2007 Retail Rate Plan, as well as decreased revenues of $7.3 million and $2.6 million related to non-operating rental income and customer contracting, respectively. Other income (expense), net increased $5.8 million, or 66.5%, in 2007 primarily due to $4.0 million from land and timber sales. Other income (expense), net increased $1.9 million, or 26.7%, in 2006 primarily due to reduced expenses of $2.9 million and $5.0 million related to the employee stock ownership plan and charitable donations, respectively, and increased revenues of $3.6 million, $5.4 million, and $3.4 million related to a residential pricing program, customer contracting, and customer facilities charges, respectively. These increases were partially offset by net financial gains on gas hedges of $18.6 million in 2005.

Income Taxes

Income taxes increased $70.0 million, or 16.8%, in 2008 primarily due to increased pre-tax net income and the 2007 Tallulah Gorge donation. These increases were partially offset by an increase in AFUDC, which is non-taxable, as well as additional state tax credits and an increase in the federal production activities deduction. Income taxes decreased $24.8 million, or 5.6%, in 2007 primarily due to state and federal deductions for the Company's donation of 2,200 acres in the Tallulah Gorge area to the State of Georgia and higher federal manufacturing deductions. In 2006, income taxes decreased $5.1 million, or 1.1%, primarily due to the recognition of state tax credits. See Note 5 to the financial statements for additional information.

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of historical costs. When historical costs are included, or when inflation exceeds projected costs used in rate regulation or market-based prices, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, income tax laws are based on historical costs. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss or the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt, preferred securities, preferred stock, and preference stock. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Georgia PSC under cost-based regulatory principles. Prices for electricity relating to wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are set by the FERC. Retail rates and revenues are reviewed and adjusted periodically with certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "Retail Regulatory Matters" and "FERC Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales during the current economic downturn, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the service area. Recent recessionary conditions have negatively impacted sales growth. The timing and extent of the economic recovery will impact future earnings.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental statutes and regulations are adopted or modified. Under the 2007 Retail Rate Plan, an environmental compliance cost recovery (ECCR) tariff was implemented on January 1, 2008 to allow for the recovery of most of the costs related to environmental controls mandated by state and federal regulation scheduled for completion between 2008 and 2010. The Company has also requested that the Georgia PSC certify the construction of environmental controls for Plants Branch and Hammond. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities including the Company's Plants Bowen and Scherer. After Alabama Power was dismissed from the original action for jurisdictional reasons, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The action against the Company has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law

public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2008, the Company had invested approximately $3.1 billion in capital projects to comply with these requirements, with annual totals of $689 million, $856 million, and $352 million for 2008, 2007, and 2006, respectively. The Company expects that capital expenditures to ensure compliance with existing and new statutes and regulations will be an additional $472 million, $334 million, and $399 million for 2009, 2010, and 2011, respectively. The Company's compliance strategy can be affected by changes to existing environmental laws, statutes, and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Compliance with any new federal or state legislation or regulations related to global climate change, air quality, combustion byproducts, including coal ash, or other environmental and health concerns could also significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2008, the Company had spent approximately $2.8 billion in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently being installed at several plants to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2004, the EPA designated nonattainment areas under an eight-hour ozone standard. Areas within the Company's service area that were designated as nonattainment under the eight-hour ozone standard included Macon and a 20-county area within metropolitan Atlanta. The Macon area has since been redesignated as an attainment area by the EPA, and a maintenance plan to address future exceedances of the standard has been approved. A state plan for bringing the Atlanta area into attainment with this standard was due to the EPA in 2007; however, in December 2006, the U.S. Court of Appeals for the District of Columbia Circuit vacated the EPA rules

designed to provide states with the guidance necessary to develop such plans. State plans could require additional reductions in NOx emissions from power plants. On March 12, 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard which will likely result in designation of new nonattainment areas within the Company's service territory. The EPA is expected to publish those designations in 2010 and require state implementation plans for any nonattainment areas by 2013.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for several areas within the Company's service area. State plans for addressing the nonattainment designations for this standard were due by April 5, 2008 but have not been finalized. These state plans could require further reductions in SO_2 and NO_x emissions from power plants.

The EPA issued the final Clean Air Interstate Rule (CAIR) in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including Georgia, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating CAIR in its entirety and remanding it to the EPA for further action consistent with its opinion. On December 23, 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit altered its July decision in response to a rehearing petition and remanded CAIR to the EPA without vacatur, thereby leaving CAIR compliance requirements in place while the EPA develops a revised rule. The State of Georgia has completed plans to implement CAIR and has approved a "multi-pollutant rule" that requires plant-specific emission controls on all but the smallest generating units in Georgia to be installed according to a schedule set forth in the rule. The rule is designed to ensure reductions in emissions of SO_2, NO_x, and mercury in Georgia. Emission reductions are thus being accomplished by the installation of emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances. The full impact of the court's remand and the outcome of the EPA's future rulemaking in response cannot be determined at this time.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress by 2018 toward the natural conditions goal. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the CAIR satisfies BART requirements for SO_2 and NO_x. Extensive studies were performed for each of the Company's affected units to demonstrate that additional particulate matter controls are not necessary under BART. At the request of the State of Georgia, additional analyses were performed for certain units in Georgia to demonstrate that no additional SO_2 controls were required to demonstrate reasonable progress. States have completed or are currently completing implementation plans that contain strategies for BART and any other measures required to achieve the first phase of reasonable progress.

The impacts of the eight-hour ozone nonattainment designations, the fine particulate matter nonattainment designations, and the Clean Air Visibility Rule on the Company cannot be determined at this time and will depend on the resolution of any pending legal challenges and the development and implementation of rules at the state level.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2 and NO_x emission controls within the next several years to ensure continued compliance with applicable air quality requirements.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The final Clean Air Mercury Rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners alleged that the EPA was not authorized to establish a cap-and-trade program for mercury emissions and instead the EPA must establish maximum achievable control technology standards for coal-fired electric utility steam generating units. On February 8, 2008, the court ruled in favor of the petitioners and vacated the Clean Air Mercury Rule. The Company's overall environmental compliance strategy relies primarily on a combination of SO_2 and NO_x controls to reduce mercury emissions. Any significant changes in the strategy will depend on the outcome of any appeals and/or future federal and state rulemakings. Future rulemakings necessitated by the court's decision could require emission reductions more stringent than those required by the Clean Air Mercury Rule.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. In January 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to the EPA for revisions. The decision has been appealed to the U.S. Supreme Court. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions and renewable energy standards continue to be strongly considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. The ultimate outcome of these proposals cannot be determined at this time; however, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that will follow from this response may have implications for both new and existing stationary sources, such as power plants. The ultimate outcome of these rulemaking activities cannot be determined at this time; however, as with the current legislative proposals, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In addition, some states are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. For example, on June 25, 2008, Florida's Governor signed comprehensive energy-related legislation that includes authorization for the Florida Department of Environmental Protection to adopt rules for a cap-and-trade regulatory program to address greenhouse gas emissions from electric utilities, conditioned upon their ratification by the legislature no sooner than the 2010 legislative session. This legislation also authorizes the Florida PSC to adopt a renewable portfolio standard for public utilities, subject to legislative ratification. The impact of any similar state legislation on the Company will depend on the future development, adoption, legislative ratification, implementation, and potential legal challenges to rules governing greenhouse gas emissions and mandates regarding the use of renewable energy, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2012 timeframe, with a conclusion to this round of negotiations targeted for the end of 2009. The outcome and impact of the international negotiations cannot be determined at this time.

The Company is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. These include the proposed construction of two additional nuclear generating units at Plant Vogtle and additional renewable energy investments, including the proposed conversion of Plant Mitchell from coal-fired to biomass generation. The Company is currently considering additional projects and is pursuing research into the costs and viability of other renewable technologies for Georgia.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $5.8 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Generation Interconnection Agreements

In November 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities. No other similar complaints are pending with the FERC.

In January 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order required the modification of Tenaska's interconnection agreements, under the provisions of the order the Company determined that no refund was payable to Tenaska. The Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of the FERC's methodology for determining the amount of refunds. The requested rehearings were denied and the Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

PSC Matters

Rate Plans

In December 2007, the Georgia PSC approved the 2007 Retail Rate Plan for the years 2008 through 2010. Under the 2007 Retail Rate Plan, the Company's earnings will continue to be evaluated against a retail return on common equity (ROE) range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% will be applied to rate refunds with the remaining one-third applied to an ECCR tariff. The Company agreed that it will not file for a general base rate increase during this period unless its projected retail ROE falls below 10.25%. Retail base rates increased by approximately $99.7 million effective January 1, 2008 to provide for cost recovery of transmission, distribution, generation and other investments, as well as increased operating costs. In addition, the ECCR tariff was implemented to allow for the recovery of costs for required environmental projects mandated by state and federal regulations. The ECCR tariff increased rates by approximately $222 million effective January 1, 2008.

The Company is required to file a general rate case by July 1, 2010, in response to which the Georgia PSC would be expected to determine whether the 2007 Retail Rate Plan should be continued, modified, or discontinued. See Note 3 to the financial statements under "Retail Regulatory Matters – Rate Plans" for additional information.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In June 2006, the Georgia PSC approved an increase in the Company's total annual billings of approximately $400 million.

In February 2007, the Georgia PSC approved an increase in the Company's total annual billings of approximately $383 million effective March 1, 2007. On May 20, 2008, the Georgia PSC approved an additional increase of approximately $222 million effective June 1, 2008. In compliance with the order, the Company is required to file a new fuel cost recovery rate by March 1, 2009. On February 19, 2009, the Georgia PSC approved the Company's request to delay the filing of that case until March 13, 2009. The new rates are expected to become effective on June 1, 2009. As of December 31, 2008, the Company had a total under recovered fuel cost balance of approximately $764.4 million, of which approximately $223.9 million is not included in current rates.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. Approximately $425.6 million of the under recovered regulatory clause revenues for the Company is included in deferred charges and other assets at December 31, 2008. See Note 1 to the financial statements under "Revenues" and Note 3 to the financial statements under "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Income Tax Matters

Legislation

On February 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA include an extension of bonus depreciation and multiple renewable energy incentives. These incentives could have a significant impact on the Company's future cash flow and net income. Additionally, the ARRA includes programs for renewable energy, transmission and smart grid enhancement, fossil energy and research, and energy efficiency and conservation. The ultimate impact cannot be determined at this time.

Georgia State Income Tax Credits

The Company's 2005 through 2008 income tax filings for the State of Georgia include state income tax credits for increased activity through Georgia ports. The Company has also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue (DOR) has not responded to these claims. In July 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. An unrecognized tax benefit has been recorded related to these credits. If the Company prevails, these claims could have a significant, and possibly material, positive effect on the Company's net income. If the Company is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on the Company's cash flow. The ultimate outcome of this matter cannot now be determined. See Note 3 under "Income Tax Matters" and Note 5 under "Unrecognized Tax Benefits" for additional information.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the Internal Revenue Code of 1986, as amended (Internal Revenue Code), Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The Internal Revenue Service (IRS) has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction to conform to the agreement. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Nuclear

Construction

In August 2006, Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation, the Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, an incorporated municipality in the State of Georgia acting by and through its Board of Water, Light, and Sinking Fund Commissioners (collectively, Owners), filed an application with the Nuclear Regulatory Commission (NRC) for an early site permit relating to two additional nuclear units on the site of Plant Vogtle. See Note 4 to the financial statements for additional information on these co-owners. On March 31, 2008, Southern Nuclear filed an application with the NRC for a combined construction and operating license (COL) for the new units.

On April 8, 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners will pay a purchase price that will be subject to certain price escalation and adjustments, adjustments for change orders, and performance bonuses. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share, based on its current ownership interest, is 45.7%. Under the terms of a separate joint development agreement, the Owners finalized their ownership percentages on July 2, 2008, except for allowed changes, under certain limited circumstances, during the Georgia PSC certification process.

On August 1, 2008, the Company submitted an application for the Georgia PSC to certify the project. Hearings began November 3, 2008 and a final certification decision is expected in March 2009.

If certified by the Georgia PSC and licensed by the NRC, Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively. The total plant value to be placed in service will also include financing costs for each of the Owners, the impacts of inflation on costs, and transmission and other costs that are the responsibility of the Owners. The Company's proportionate share of the estimated in-service costs, based on its current ownership interest, is approximately $6.4 billion, subject to adjustments and performance bonuses under the Vogtle 3 and 4 Agreement.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Owners and the Consortium also have agreed to certain bonuses payable to the Consortium for early completion and unit performance. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

The obligations of Westinghouse Electric Company LLC and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Vogtle 3 and 4 Agreement is subject to certification by the Georgia PSC. In addition, the Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

In connection with the certification application, the Company has requested Georgia PSC approval to include the construction work in progress accounts for Plant Vogtle Units 3 and 4 in rate base and allow the Company to recover financing costs during the construction period.

On February 11, 2009, the Georgia State Senate passed Senate Bill 31 that would allow the Company to recover financing costs for nuclear construction projects by including the related construction work in progress accounts in rate base during the construction period. A similar bill is being considered in the Georgia State House of Representatives.

If the Company is not permitted to recover these costs during the construction period, the estimated capital expenditures would increase by approximately $144 million in 2011. See FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein and Note 7 to the financial statements under "Construction Program" for these forecasted capital expenditures.

The ultimate outcome of these matters cannot now be determined.

Relicensing

The NRC operating licenses for Plant Vogtle Units 1 and 2 currently expire in January 2027 and February 2029, respectively. In June 2007, the Company filed an application with the NRC to extend the licenses for Plant Vogtle Units 1 and 2 for an additional 20 years. The Company anticipates the NRC may make a decision regarding the license extension for Plant Vogtle in 2009.

Other Matters

The Company has initiated a voluntary attrition plan under which participating employees may elect to resign from their positions as of March 31, 2009. Approximately 700 employees who have indicated an interest in participating in the plan have been selected by the Company and are permitted to resign and receive severance. Each participating employee who resigns under the plan will be entitled to receive a severance payment equal to his or her annual base salary, accrued vacation, and pro-rated bonus as of March 31, 2009. The Company will record a charge during the first quarter of 2009 in connection with the plan. The ultimate amount of the charge will be dependent on the total number of employees who elect to resign under the plan. Such charge could have a material impact on the Company's statements of income for the quarter ending March 31, 2009 and statements of cash flows for the six months ending June 30, 2009. The first quarter 2009 charge will generally be offset with lower salary costs for the remainder of the year and is not expected to have a material impact on the Company's financial statements for the year ending December 31, 2009.

The Company is involved in various other matters being litigated, regulatory matters, and certain tax-related issues that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the following critical accounting policies and estimates with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Georgia PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation, nuclear decommissioning, and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with generally accepted accounting principles, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or Georgia DOR interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of new or existing matters through the legislative process, the court systems, the IRS, the FERC, or the EPA.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, and power delivery volume and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2008. Throughout the recent turmoil in the financial markets, the Company has maintained adequate access to capital without drawing on any of its committed bank credit arrangements used to support its commercial paper programs and variable rate pollution control revenue bonds. The Company has continued to issue commercial paper at reasonable rates. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. No material changes in bank credit arrangements have occurred although market rates for committed credit have increased and the Company may be subject to higher costs as its existing facilities are replaced or renewed. The Company's interest cost for short-term debt has decreased as market short-term interest rates have declined. The ultimate impact on future financing costs as a result of the financial turmoil cannot be determined at this time. The Company experienced no material counterparty credit losses as a result of the turmoil in the financial markets. See "Sources of Capital" and "Financing Activities" herein for additional information.

The Company's investments in pension and nuclear decommissioning trust funds declined in value as of December 31, 2008. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future fund performance and cannot be determined at this time. The Company does not expect any changes to funding obligations to the nuclear decommissioning trusts at this time.

Cash flow from operations totaled $1.7 billion in 2008, an increase of $279.2 million from 2007, primarily due to higher retail operating revenues partially offset by higher inventory additions. Cash flow from operations in 2007 totaled $1.4 billion, an increase of $248.5 million from 2006, primarily due to higher retail revenues primarily related to higher fuel cost recovery revenues and less cash used for working capital primarily from lower inventory additions and increases in other current liabilities. Cash flow from operations increased $117.4 million in 2006, primarily from increased retail operating revenues partially offset by higher fuel inventories and an increase in under recovered deferred fuel costs.

Net cash used for investing activities totaled $1.9 billion, $1.9 billion, and $1.2 billion in 2008, 2007, and 2006, respectively, due to gross property additions primarily related to installation of equipment to comply with environmental standards, construction of generation, transmission and distribution facilities, and purchase of nuclear fuel. The majority of funds needed for gross property additions for the last several years have been provided from operating activities, capital contributions from Southern Company, and the issuance of long and short-term debt and preference stock.

Cash provided from financing activities totaled $309.8 million, $429.7 million, and $46.4 million for 2008, 2007, and 2006, respectively. These totals are primarily related to additional issuances of senior notes in 2008 and 2007, and the issuance of short-term debt in 2006. The statements of cash flows provide additional details. See "Financing Activities" herein.

Significant balance sheet changes in 2008 include a $1.1 billion increase in long-term debt primarily to replace short-term debt and provide funds for the Company's continuous construction program and an increase in total property, plant, and equipment of $1.3 billion. Other significant balance sheet changes include a decrease of $1.0 billion in prepaid pension costs, an increase of $908 million in other regulatory assets, and a decrease of $462 million in other regulatory liabilities primarily attributable to the decline in market value of the Company's pension trust fund. Significant balance sheet changes in 2007 include a $726 million increase in long-term debt and a $221 million increase in preferred and preference stock primarily to replace short-term debt and provide funds for the

Company's continuous construction programs. Other balance sheet changes in 2007 include an increase in total property, plant and equipment of $1.3 billion and a $206 million decrease in the under recovered fuel balance.

The Company's ratio of common equity to total capitalization -- including short-term debt – was 46.5% in 2008, 47.5% in 2007, and 48.6% in 2006. The Company has received investment grade credit ratings from the major rating agencies with respect to debt, preferred securities, preferred stock, and preference stock. See SELECTED FINANCIAL AND OPERATING DATA for additional information regarding the Company's security ratings.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, security issuances, term loans, short-term borrowings, and equity contributions from Southern Company. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approvals, and other factors. The issuance of long-term securities by the Company is subject to the approval of the Georgia PSC. In addition, the issuance of short-term debt securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended. The amounts of securities authorized by the Georgia PSC and the FERC are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source for under recovered fuel costs and to meet cash needs which can fluctuate significantly due to the seasonality of the business.

To meet short-term cash needs and contingencies, at December 31, 2008 the Company had credit arrangements with banks totaling $1.3 billion. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

At December 31, 2008, bank credit arrangements were as follows:

		Expires	
Total	Unused	2009	2012
	(in millions)		
$1,345	$1,333	$225	$1,120

Of the credit arrangements that expire in 2009, $40 million allow for the execution of term loans for an additional two-year period.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from issuances for the benefit of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. As of December 31, 2008, the Company had $256.3 million of outstanding commercial paper and a $100 million short-term bank loan outstanding.

Financing Activities

During 2008, the Company issued $1.0 billion of senior notes and incurred $312 million of obligations related to the issuance of pollution control revenue bonds. The issuances were used to reduce the Company's short-term indebtedness, fund senior note maturities totaling $198 million, redeem pollution control revenue bonds totaling $259 million, and fund the Company's ongoing construction program.

During 2008, the Company settled interest rate hedges of $325 million related to the issuance of senior notes at a loss of $20 million. Additionally, interest rate hedges of $100 million were settled early at a loss of $2 million related to counterparty credit issues.

In 2008, the Company converted its entire $819 million of obligations related to auction rate pollution control revenue bonds from auction rate modes to other interest rate modes. Initially, approximately $332 million of the auction rate pollution control revenue bonds were converted to fixed interest rate modes and approximately $487 million were converted to variable rate modes. The Company subsequently converted approximately $203 million of its variable rate pollution control revenue bonds to fixed interest rate modes. The Company also incurred obligations related to the issuance of $53 million of pollution control revenue bonds for the Company's Plant Hammond project. At December 31, 2008 the trustee held $22.4 million of the proceeds, which will be transferred to the Company for reimbursement of project costs.

In September 2008, the Company was required to purchase a total of approximately $76.6 million of variable rate pollution control revenue bonds that were tendered by investors. The Company subsequently remarketed $74.5 million of the tendered bonds. The remaining $2.1 million were extinguished.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Subsequent to December 31, 2008, the Company issued $500 million of Series 2009A 5.95% Senior Notes due February 1, 2039. The proceeds were used by the Company to repay at maturity $150 million aggregate principal amount of the Company's Series U Floating Rate Senior Notes due February 7, 2009, to repay a portion of short-term indebtedness, and for general corporate purposes. The Company settled $100 million of hedges related to the issuance at a loss of approximately $16 million.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances, energy price risk management, and for construction of new generation. At December 31, 2008, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $27 million. At December 31, 2008, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $961 million. Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market rate volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, where possible, the Company nets the exposures to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including, but not limited to, market valuation, value at risk, stress tests, and sensitivity analysis.

To mitigate future exposure to changes in interest rates, the Company enters into forward starting interest rate swaps and other derivatives that have been designated as hedges. These derivatives have a notional amount of $851 million and are related to anticipated debt issuances and certain variable rate debt over the next two years. The weighted average interest rate on $291 million of outstanding variable rate long-term debt that has not been hedged at January 1, 2009 was 2.24%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $3 million at January 1, 2009. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for gas purchases.

The changes in fair value of energy-related derivative contracts were as follows at December 31:

	2008 Changes	2007 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (0.4)**	$ (38.0)
Contracts realized or settled	**(68.5)**	41.6
Current period changes[(a)]	**(44.3)**	(4.0)
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (113.2)**	$ (0.4)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any

The decrease in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2008 was $112.8 million, substantially all of which is due to natural gas positions. This change is attributable to both the volume and prices of natural gas. At December 31, 2008, the Company had a net hedge volume of 59.3 billion cubic feet (Bcf) with a weighted average contract cost approximately $1.96 per million British thermal units (mmBtu) above market prices, compared to 44.1 Bcf at December 31, 2007 with a weighted average contract cost approximately $0.02 per mmBtu above market prices. These natural gas hedges are designated as regulatory hedges.

Energy-related derivative contracts which are designated as regulatory hedges relate to the Company's fuel hedging program where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism.

Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Unrealized pre-tax gains/(losses) recognized in income for energy-related derivative contracts that are not hedges were not material for any year presented.

The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

	December 31, 2008 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	**$ -**	**$ -**	**$ -**	**$ -**
Level 2	**(113.2)**	**(80.7)**	**(32.4)**	**(0.1)**
Level 3	**-**	**-**	**-**	**-**
Fair value of contracts outstanding at end of period	**$ (113.2)**	**$ (80.7)**	**$ (32.4)**	**$ (0.1)**

As part of the adoption of FASB Statement No. 157, "Fair Value Measurements" to increase consistency and comparability in fair value measurements and related disclosures, the table above now uses the three-tier fair value hierarchy, as discussed in Note 10 to the financial statements, as opposed to the previously used descriptions "actively quoted," "external sources," and "models and other methods." The three-tier fair value hierarchy focuses on the fair value of the contract itself, whereas the previous descriptions focused on the source of the inputs. Because the Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, the valuations of those contracts now appear in Level 2; previously they were shown as "actively quoted."

The Company is exposed to market risk in the event of nonperformance by counterparties to the energy-related and interest rate derivative contracts. The Company's practice is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $2.8 billion for 2009, $2.6 billion for 2010, and $2.6 billion for 2011. This estimate assumes the Company's current request to include construction work in progress for Plant Vogtle Units 3 and 4 in rates is granted by the Georgia PSC or the Georgia legislature, beginning in 2011. If not, the estimate will increase by approximately $144 million in 2011. Environmental expenditures included in these estimated amounts are $472 million, $334 million, and $399 million for 2009, 2010, and 2011, respectively. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

As a result of requirements by the NRC, the Company has established external trust funds for nuclear decommissioning costs. For additional information, see Note 1 to the financial statements under "Nuclear Decommissioning."

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the Georgia PSC and the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt and preferred securities and the related interest, preferred and preference stock dividends, leases, derivative obligations, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2009	2010-2011	2012-2013	After 2013	Uncertain Timing [d]	Total
			(in millions)			
Long-term debt[a] –						
Principal	$ 280	$ 667	$ 734	$ 5,612	$ -	$ 7,293
Interest	354	677	636	5,711	-	7,378
Preferred and preference stock dividends[b]	17	35	35	-	-	87
Energy-related derivative obligations[c]	85	33	-	-	-	118
Interest derivatives	21	-	-	-	-	21
Operating leases	43	65	32	28	-	168
Unrecognized tax benefits and interest[d]	142	-	-	-	9	151
Purchase commitments[e] –						
Capital[f]	2,615	4,942	-	-	-	7,557
Limestone [g]	10	34	31	37	-	112
Coal	2,497	3,713	1,406	1,999	-	9,615
Nuclear fuel	139	219	199	33	-	590
Natural gas[h]	657	631	744	2,917	-	4,949
Purchased power	370	656	506	2,186	-	3,718
Long-term service agreements[i]	14	32	103	581	-	730
Trusts –						
Nuclear decommissioning[j]	3	7	7	53	-	70
Postretirement benefits[k]	39	81	-	-	-	120
Total	$7,286	$11,792	$4,433	$ 19,157	$ 9	$ 42,677

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2009, as reflected in the statements of capitalization. Fixed rates include, where applicable, the effects of interest rate derivatives employed to manage interest rate risk.

(b) Preferred and preference stock does not mature; therefore, amounts provided are for the next five years only.

(c) For additional information see Notes 1 and 6 to the financial statements.

(d) The timing related to the realization of $9 million in unrecognized tax benefits and interest payments cannot be reasonably and reliably estimated due to uncertainties in the timing of the effective settlement of tax positions. Of the total $151 million, $81 million is the estimated cash payment. See Note 3 and Note 5 to the financial statements for additional information.

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $1.6 billion, $1.6 billion, and $1.6 billion, respectively.

(f) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures, excluding those amounts related to contractual purchase commitments for nuclear fuel. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program.

(g) As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has begun construction of flue gas desulfurization projects and has entered into various long-term commitments for the procurement of limestone to be used in such equipment.

(h) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2008.

(i) Long-term service agreements include price escalation based on inflation indices.

(j) Projections of nuclear decommissioning trust contributions are based on the 2007 Retail Rate Plan.

(k) The Company forecasts postretirement trust contributions over a three-year period. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time. Therefore, no amounts related to the pension trust fund are included in the table. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2008 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, retail rates, fuel cost recovery and other rate actions, environmental regulations and expenditures, the Company's projections for postretirement benefit and nuclear decommissioning trust contributions, financing activities, access to sources of capital, the impacts of the adoption of new accounting rules, estimated sales and purchases under new power sale and purchase agreements, completion of construction projects, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and the pending EPA civil action against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population, business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate cases related to fuel cost recovery;
- regulatory approvals related to the potential Plant Vogtle expansion, including Georgia PSC and NRC approvals;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

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STATEMENTS OF INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Georgia Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Revenues:			
Retail revenues	**$7,286,345**	$6,498,003	$6,205,620
Wholesale revenues --			
Non-affiliates	**568,797**	537,913	551,731
Affiliates	**286,219**	277,832	252,556
Other revenues	**270,191**	257,904	235,737
Total operating revenues	**8,411,552**	7,571,652	7,245,644
Operating Expenses:			
Fuel	**2,812,417**	2,640,526	2,233,029
Purchased power --			
Non-affiliates	**442,951**	332,064	332,606
Affiliates	**962,100**	718,327	812,433
Other operations and maintenance	**1,580,922**	1,561,736	1,560,469
Depreciation and amortization	**636,970**	511,180	498,754
Taxes other than income taxes	**316,219**	291,136	298,824
Total operating expenses	**6,751,579**	6,054,969	5,736,115
Operating Income	**1,659,973**	1,516,683	1,509,529
Other Income and (Expense):			
Allowance for equity funds used during construction	**95,294**	68,177	31,524
Interest income	**7,219**	3,560	2,459
Interest expense, net of amounts capitalized	**(345,416)**	(343,462)	(317,947)
Other income (expense), net	**(9,258)**	14,705	8,833
Total other income and (expense)	**(252,161)**	(257,020)	(275,131)
Earnings Before Income Taxes	**1,407,812**	1,259,663	1,234,398
Income taxes	**487,504**	417,521	442,334
Net Income	**920,308**	842,142	792,064
Dividends on Preferred and Preference Stock	**17,381**	6,006	4,839
Net Income After Dividends on Preferred and Preference Stock	**$902,927**	$836,136	$787,225

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2008, 2007, and 2006

Georgia Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Activities:			
Net income	**$ 920,308**	$ 842,142	$ 792,064
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**758,283**	616,796	588,428
Deferred income taxes and investment tax credits, net	**170,958**	(78,010)	16,159
Deferred revenues	**122,964**	4,871	(136)
Allowance for equity funds used during construction	**(95,294)**	(68,177)	(31,524)
Pension, postretirement, and other employee benefits	**(3,243)**	8,836	18,604
Stock based compensation expense	**4,200**	5,977	5,805
Hedge settlements	**(22,949)**	12,121	-
Other, net	**909**	18,550	4,592
Changes in certain current assets and liabilities --			
Receivables	**(82,995)**	134,276	1,193
Fossil fuel stock	**(91,536)**	(1,211)	(194,256)
Materials and supplies	**(20,021)**	(32,998)	31,317
Prepaid income taxes	**(14,885)**	10,002	1,060
Other current assets	**(18,460)**	(4,359)	774
Accounts payable	**(56,126)**	22,626	(85,189)
Accrued taxes	**117,524**	(33,320)	82,735
Accrued compensation	**21,525**	(30,039)	(10,328)
Other current liabilities	**16,789**	20,703	(21,054)
Net cash provided from operating activities	**1,727,951**	1,448,786	1,200,244
Investing Activities:			
Property additions	**(1,847,952)**	(1,765,344)	(1,219,498)
Investment in restricted cash from pollution control bonds	**-**	(59,525)	-
Distribution of restricted cash from pollution control bonds	**32,675**	-	-
Nuclear decommissioning trust fund purchases	**(419,086)**	(448,287)	(464,274)
Nuclear decommissioning trust fund sales	**412,206**	441,407	457,394
Cost of removal net of salvage	**(62,722)**	(47,565)	(33,620)
Change in construction payables, net of joint owner portion	**2,639**	24,893	35,075
Other	**(38,199)**	(25,479)	(16,005)
Net cash used for investing activities	**(1,920,439)**	(1,879,900)	(1,240,928)
Financing Activities:			
Increase (decrease) in notes payable, net	**(358,497)**	(17,690)	406,768
Proceeds --			
Senior notes	**1,000,000**	1,500,000	150,000
Preferred and preference stock	**-**	225,000	-
Pollution control revenue bonds	**386,485**	190,800	153,910
Capital contributions from parent company	**272,894**	322,448	312,544
Other long-term debt	**301,100**	-	-
Redemptions --			
Pollution control revenue bonds	**(335,605)**	-	(153,910)
Capital leases	**(1,125)**	(2,185)	(136)
Senior notes	**(198,097)**	(300,000)	(150,000)
First mortgage bonds	**-**	-	(20,000)
Preferred and preference stock	**-**	-	(14,569)
Other long-term debt	**-**	(762,887)	-
Payment of preferred and preference stock dividends	**(17,016)**	(3,143)	(2,958)
Payment of common stock dividends	**(721,200)**	(689,900)	(630,000)
Other	**(19,104)**	(32,787)	(5,253)
Net cash provided from financing activities	**309,835**	429,656	46,396
Net Change in Cash and Cash Equivalents	**117,347**	(1,458)	5,712
Cash and Cash Equivalents at Beginning of Year	**15,392**	16,850	11,138
Cash and Cash Equivalents at End of Year	**$ 132,739**	$ 15,392	$ 16,850
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $39,807, $28,668, and $12,530 capitalized, respectively)	**$309,264**	$317,938	$317,536
Income taxes (net of refunds)	**279,904**	456,852	398,735

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2008 and 2007
Georgia Power Company 2008 Annual Report

Assets	2008	2007
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 132,739	$ 15,392
Restricted cash	22,381	48,279
Receivables --		
Customer accounts receivable	554,220	491,389
Unbilled revenues	147,978	137,046
Under recovered regulatory clause revenues	338,780	384,538
Other accounts and notes receivable	97,898	147,498
Affiliated companies	13,091	21,699
Accumulated provision for uncollectible accounts	(10,732)	(7,636)
Fossil fuel stock, at average cost	484,757	393,222
Materials and supplies, at average cost	356,537	337,652
Vacation pay	71,217	69,394
Prepaid income taxes	65,987	51,101
Other	182,425	55,169
Total current assets	2,457,278	2,144,743
Property, Plant, and Equipment:		
In service	23,975,262	22,011,215
Less accumulated provision for depreciation	9,101,474	8,696,668
	14,873,788	13,314,547
Nuclear fuel, at amortized cost	278,412	198,983
Construction work in progress	1,434,989	1,797,642
Total property, plant, and equipment	16,587,189	15,311,172
Other Property and Investments:		
Equity investments in unconsolidated subsidiaries	57,163	53,813
Nuclear decommissioning trusts, at fair value	460,430	588,952
Other	40,945	47,914
Total other property and investments	558,538	690,679
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	572,528	532,539
Prepaid pension costs	-	1,026,985
Deferred under recovered regulatory clause revenues	425,609	307,294
Other regulatory assets	1,449,352	541,014
Other	265,174	268,335
Total deferred charges and other assets	2,712,663	2,676,167
Total Assets	$22,315,668	$20,822,761

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2008 and 2007
Georgia Power Company 2008 Annual Report

Liabilities and Stockholder's Equity	2008	2007
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 280,443**	$ 198,576
Notes payable	**357,095**	715,591
Accounts payable --		
Affiliated	**260,545**	236,332
Other	**422,485**	463,945
Customer deposits	**186,919**	171,553
Accrued taxes --		
Income taxes	**70,916**	68,782
Unrecognized tax benefits	**128,712**	-
Other	**278,171**	219,585
Accrued interest	**79,432**	74,674
Accrued vacation pay	**57,643**	56,303
Accrued compensation	**135,191**	114,974
Other	**249,609**	103,225
Total current liabilities	**2,507,161**	2,423,540
Long-term Debt (See accompanying statements)	**7,006,275**	5,937,792
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**3,064,580**	2,850,655
Deferred credits related to income taxes	**140,933**	146,886
Accumulated deferred investment tax credits	**256,218**	269,125
Employee benefit obligations	**882,965**	678,826
Asset retirement obligations	**688,019**	663,503
Other cost of removal obligations	**396,947**	414,745
Other regulatory liabilities	**115,865**	577,642
Other	**111,505**	158,670
Total deferred credits and other liabilities	**5,657,032**	5,760,052
Total Liabilities	**15,170,468**	14,121,384
Preferred and Preference Stock (See accompanying statements)	**265,957**	265,957
Common Stockholder's Equity (See accompanying statements)	**6,879,243**	6,435,420
Total Liabilities and Stockholder's Equity	**$22,315,668**	$20,822,761
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION

At December 31, 2008 and 2007

Georgia Power Company 2008 Annual Report

	2008	2007	2008	2007
		(in thousands)	*(percent of total)*	
Long-Term Debt:				
Long-term debt payable to affiliated trusts --				
5.88% due 2044	**$ 206,186**	$ 206,186		
Long-term notes payable --				
6.55% due May 15, 2008	**-**	45,000		
4.10% due 2009	**125,300**	125,000		
Variable rate (5.00% at 1/1/08) due 2008	**-**	150,000		
Variable rate (2.3288% at 1/1/09) due 2009	**150,000**	150,000		
Variable rate (2.42% at 1/1/09) due 2010	**250,000**	-		
Variable rate (2.35% at 1/1/09) due 2011	**300,000**	-		
4.00% to 5.57% due 2011	**101,100**	100,000		
5.125% due 2012	**200,000**	200,000		
4.90% to 6.00% due 2013	**525,000**	125,000		
5.25% to 8.20% due 2015-2048	**3,421,903**	3,075,000		
Total long-term notes payable	**5,073,303**	3,970,000		
Other long-term debt --				
Pollution control revenue bonds:				
1.95% to 5.75% due 2016-2048	**1,309,190**	774,370		
Variable rate (1.05% at 1/1/09) due 2011	**8,330**	10,450		
Variable rate (0.80% to 3.00% at 1/1/09) due 2016-2041	**628,005**	1,109,825		
Total other long-term debt	**1,945,525**	1,894,645		
Capitalized lease obligations	**67,948**	70,733		
Unamortized debt discount	**(6,244)**	(5,196)		
Total long-term debt (annual interest requirement -- $354.0 million)	**7,286,718**	6,136,368		
Less amount due within one year	**280,443**	198,576		
Long-term debt excluding amount due within one year	**7,006,275**	5,937,792	**49.5%**	47.0%
Preferred and Preference Stock:				
Non-cumulative preferred stock				
$25 par value -- 6.125%				
Authorized - 50,000,000 shares				
Outstanding - 1,800,000 shares	**44,991**	44,991		
Non-cumulative preference stock				
$100 par value -- 6.50%				
Authorized - 15,000,000 shares				
Outstanding - 2,250,000 shares	**220,966**	220,966		
Total preferred and preference stock (annual dividend requirement -- $17.4 million)	**265,957**	265,957	**1.9**	2.1
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized: 20,000,000 shares				
Outstanding: 9,261,500 shares	**398,473**	398,473		
Paid-in capital	**3,655,731**	3,374,777		
Retained earnings	**2,857,789**	2,676,063		
Accumulated other comprehensive income (loss)	**(32,750)**	(13,893)		
Total common stockholder's equity	**6,879,243**	6,435,420	**48.6**	50.9
Total Capitalization	**$14,151,475**	$12,639,169	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2008, 2007, and 2006

Georgia Power Company 2008 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)		
Balance at December 31, 2005	$398,473	$2,717,539	$2,372,637	$(36,566)	$5,452,083
Net income after dividends on preferred stock	-	-	787,225	-	787,225
Capital contributions from parent company	-	322,306	-	-	322,306
Other comprehensive income	-	-	-	5,184	5,184
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	19,489	19,489
Cash dividends on common stock	-	-	(630,000)	-	(630,000)
Other	-	-	(36)	-	(36)
Balance at December 31, 2006	398,473	3,039,845	2,529,826	(11,893)	5,956,251
Net income after dividends on preferred and preference stock	-	-	836,136	-	836,136
Capital contributions from parent company	-	334,931	-	-	334,931
Other comprehensive loss	-	-	-	(2,000)	(2,000)
Cash dividends on common stock	-	-	(689,900)	-	(689,900)
Other	-	1	1	-	2
Balance at December 31, 2007	**398,473**	**3,374,777**	**2,676,063**	**(13,893)**	**6,435,420**
Net income after dividends on preferred and preference stock	-	-	**902,927**	-	**902,927**
Capital contributions from parent company	-	**280,954**	-	-	**280,954**
Other comprehensive loss	-	-	-	**(18,857)**	**(18,857)**
Cash dividends on common stock	-	-	**(721,200)**	-	**(721,200)**
Other	-	-	(1)	-	(1)
Balance at December 31, 2008	**$398,473**	**$3,655,731**	**$2,857,789**	**$(32,750)**	**$6,879,243**

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Georgia Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Net income after dividends on preferred and preference stock	**$902,927**	$836,136	$787,225
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(13,150), $(1,831), and $(935), respectively	**(20,846)**	(2,938)	(1,454)
Reclassification adjustment for amounts included in net income, net of tax of $1,255, $278, and $(441), respectively	**1,989**	441	(700)
Marketable securities:			
Changes in fair value, net of tax of $-, $291, and $(494), respectively	-	497	(817)
Pension and other postretirement benefit plans:			
Change in additional minimum pension liability, net of tax of $-, $-, and $5,143, respectively	-	-	8,155
Total other comprehensive income (loss)	**(18,857)**	(2,000)	5,184
Comprehensive Income	**$884,070**	$834,136	$792,409

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Georgia Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies – Alabama Power Company (Alabama Power), the Company, Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power) – provide electric service in four Southeastern states. The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Georgia and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public, and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Georgia Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Reclassifications

Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. The statements of income have been modified within the operating expenses section to combine the line items "Other operations" and "Maintenance" into a single line item entitled "Other operations and maintenance." Due to materiality in the current period, the statements of cash flows for the prior periods presented were modified within the operating activities section to separately report the amount of "Deferred revenues" and "Hedge settlements" previously included in "Other, net" while the line item "Tax benefit of stock options" was collapsed into "Other, net." Within the financing activities section of the statements of cash flows in the prior periods, the amount of "Gross excess tax benefit of stock options" was combined into "Other." These reclassifications had no effect on total assets, net income, or cash flows.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $490 million in 2008, $449 million in 2007, and $393 million in 2006. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has an agreement with Southern Nuclear under which the following nuclear-related services are rendered to the Company at cost: general executive and advisory services, general operations, management and technical services, administrative services including procurement, accounting, employee relations, systems and procedures services, strategic planning and budgeting services, and other services with respect to business and operations. Costs for these services amounted to $410 million in 2008, $380 million in 2007, and $348 million in 2006.

The Company had an agreement with Southern Power under which the Company operated and maintained Southern Power's Plants Dahlberg, Franklin, and Wansley at cost. In August 2007, that agreement was terminated and replaced with a service agreement under which the Company provides to Southern Power specifically requested services. Billings under these agreements with Southern Power amounted to $1.9 million in 2008, $6.8 million in 2007, and $5.4 million in 2006.

Southern Company's 30% ownership interest in Alabama Fuel Products, LLC (AFP), which produced synthetic fuel, was terminated in July 2006. The Company had an agreement with an indirect subsidiary of Southern Company that provided services for AFP. Under this agreement, the Company provided certain accounting functions, including processing and paying fuel transportation invoices, and the Company was reimbursed for its expenses. Amounts billed under this agreement totaled approximately $85 million in 2007, and $76 million in 2006. In addition, the Company purchased synthetic fuel from AFP for use at Plant Branch. Synthetic fuel purchases totaled $278 million in both 2007 and 2006. The related party transactions and synthetic fuel purchases were terminated as of December 31, 2007.

The Company has entered into several power purchase agreements (PPAs) with Southern Power for capacity and energy. Expenses associated with these PPAs were $480 million, $440 million, and $407 million in 2008, 2007, and 2006, respectively. Additionally, the Company had $25 million and $26 million of prepaid capacity expenses included in deferred charges and other assets in the balance sheets at December 31, 2008 and 2007, respectively. See Note 7 under "Purchased Power Commitments" for additional information.

The Company has an agreement with Gulf Power under which Gulf Power jointly owns a portion of Plant Scherer. Under this agreement, the Company operates Plant Scherer, and Gulf Power reimburses the Company for its proportionate share of the related expenses which were $8.1 million in 2008, $5.1 million in 2007, and $8.0 million in 2006. See Note 4 for additional information.

In 2008, the Company purchased a compressor assembly from Southern Power for $3.9 million.

In 2007, the Company sold equipment at cost to Gulf Power for $4.0 million.

The Company provides incidental services to other Southern Company subsidiaries which are generally minor in duration and amount. The Company provided no significant storm assistance to affiliates in 2008, 2007, or 2006.

Also see Note 4 for information regarding the Company's ownership in and PPA with Southern Electric Generating Company (SEGCO) and Note 5 for information on certain deferred tax liabilities due to affiliates.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the Company's balance sheets at December 31 relate to the following:

	2008	2007	Note
	(in millions)		
Deferred income tax charges	$ 573	$ 533	(a)
Loss on reacquired debt	165	175	(b)
Vacation pay	71	69	(c)
Underfunded retiree benefit plans	903	235	(e)
Fuel-hedging (realized and unrealized) losses	130	14	(f)
Nuclear early site permit	49	28	(h)
Other regulatory assets	160	133	(d)
Asset retirement obligations	209	41	(a)
Other cost of removal obligations	(397)	(415)	(a)
Deferred income tax credits	(141)	(147)	(a)
Overfunded retiree benefit plans	-	(540)	(e)
Environmental compliance cost recovery	(135)	-	(g)
Other regulatory liabilities	(14)	(21)	(d)
Total assets (liabilities), net	$1,573	$ 105	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered, and deferred tax liabilities are amortized over the related property lives, which may range up to 60 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(b) Recovered over either the remaining life of the original issue or, if refinanced, over the life of the new issue which may range up to 50 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year.

(d) Recorded and recovered or amortized as approved by the Georgia PSC.

(e) Recovered and amortized over the average remaining service period which may range up to 16 years. See Note 2 for additional information.

(f) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed 42 months. Upon final settlement, costs are recovered through the fuel cost recovery clause.

(g) This balance represents deferred revenue associated with the Environmental Compliance Cost Recovery (ECCR) tariff established in the 2007 Retail Rate Plan (as defined below). The recovery of the forecasted environmental compliance costs was levelized to collect equal annual amounts between January 1, 2008 and December 31, 2010 under the tariff.

(h) This balance represents deferred costs incurred in support of preparation and completion of an early site permit and combined construction and operating license (COL) for two additional nuclear generating units at Plant Vogtle (Units 3 and 4). The costs will be capitalized to construction work in progress upon certification by the Georgia PSC.

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS No. 71, the Company would be required to write off or reclassify to accumulated other comprehensive income related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair value. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues are accrued at the end of each fiscal period. Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs and the energy component of purchased power costs, and certain other costs. Revenues are adjusted for differences between the actual recoverable costs and amounts billed in current regulated rates.

Retail fuel cost recovery rates require periodic filings with the Georgia PSC. In compliance with the order, the Company is required to file a new fuel cost recovery rate by March 1, 2009. On February 19, 2009, the Georgia PSC approved the Company's request to delay the filing of that case until March 13, 2009. The new rates are expected to become effective on June 1, 2009. See Note 3 under "Retail Regulatory Matters – Fuel Cost Recovery." The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense includes the cost of purchased emission allowances as they are used. Fuel expense also includes the amortization of the cost of nuclear fuel and a charge, based on nuclear generation, for the permanent disposal of spent nuclear fuel. See Note 3 under "Nuclear Fuel Disposal Costs" for additional information.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income. In accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost, less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction.

The Company's property, plant, and equipment consisted of the following at December 31:

	2008	2007
	(in millions)	
Generation	**$ 11,478**	$10,180
Transmission	**3,764**	3,593
Distribution	**7,409**	6,985
General	**1,296**	1,225
Plant acquisition adjustment	**28**	28
Total plant in service	**$ 23,975**	$22,011

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed with the exception of certain generating plant maintenance costs. As mandated by the Georgia PSC, the Company defers and amortizes nuclear refueling costs over the unit's operating cycle before the next refueling. The refueling cycles are 18 and 24 months for Plants Vogtle and Hatch, respectively. Also, in accordance with the Georgia PSC, the Company defers the costs of certain significant inspection costs for the combustion turbines at Plant McIntosh and amortizes such costs over 10 years, which approximates the expected maintenance cycle.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 2.9% in 2008 and 2.6% in 2007 and 2006. Depreciation studies are conducted periodically to update the composite rates that are approved by the Georgia PSC. Effective January 1, 2008, the Company's depreciation rates were revised by the Georgia PSC.

When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Under the Company's retail rate plan for the three years ended December 31, 2007 (2004 Retail Rate Plan), the Company was ordered to recognize Georgia PSC–certified capacity costs in rates evenly over the three years covered by the 2004 Retail Rate Plan. The Company recorded credits to amortization of $19 million and $14 million in 2007 and 2006, respectively. The retail rate plan for the three years ending December 31, 2010 (2007 Retail Rate Plan) did not include a similar order. See Note 3 under "Retail Regulatory Matters – Rate Plans" for additional information.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Georgia PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability.

The liability recognized to retire long-lived assets primarily relates to the Company's nuclear facilities, which include the Company's ownership interests in Plants Hatch and Vogtle. The fair value of assets legally restricted for settling retirement obligations related to nuclear facilities as of December 31, 2008 was $460 million. In addition, the Company has retirement obligations related to various landfill sites, ash ponds, underground storage tanks, and asbestos removal. The Company also has identified retirement obligations related to certain transmission and distribution facilities, leasehold improvements, equipment on customer property, and property associated with the Company's rail lines. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income the allowed removal costs in accordance with its regulatory treatment. Any difference between costs recognized under FASB Statement No. 143, "Accounting for Asset Retirement Obligations" and FASB Interpretation No. 47, "Conditional Asset Retirement Obligations" and those reflected in rates are recognized as either a regulatory asset or liability in the balance sheets as ordered by the Georgia PSC. See "Nuclear Decommissioning" herein for further information on amounts included in rates.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2008	2007
	(in millions)	
Balance beginning of year	**$ 664**	$ 627
Liabilities incurred	**4**	-
Liabilities settled	**(1)**	(3)
Accretion	**41**	40
Cash flow revisions	**(18)**	-
Balance end of year	**$ 690**	$ 664

Nuclear Decommissioning

The Nuclear Regulatory Commission (NRC) requires licensees of commercial nuclear power reactors to establish a plan for providing reasonable assurance of funds for future decommissioning. The Company has external trust funds (the Funds) to comply with the NRC's regulations. Use of the Funds is restricted to nuclear decommissioning activities and the Funds are managed and invested in accordance with applicable requirements of various regulatory bodies, including the NRC, the FERC, and the Georgia PSC, as well as

the Internal Revenue Service (IRS). The Funds are invested in a tax-efficient manner in a diversified mix of equity and fixed income securities and are reported as of December 31, 2008 as trading securities pursuant to FASB Statement No. 115, "Accounting for Certain Investments in Debt and Equity Securities" (SFAS No. 115).

On January 1, 2008, the Company adopted FASB Statement No. 159, "Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115" (SFAS No. 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. The Company elected the fair value option only for investment securities held in the Funds. The Funds are included in the balance sheets at fair value, as disclosed in Note 10.

Management elected to continue to record the Funds at fair value because management believes that fair value best represents the nature of the Funds. Management has delegated day-to-day management of the investments in the Funds to unrelated third party managers with oversight by Southern Company and Company management. The managers of the Funds are authorized, within broad limits, to actively buy and sell securities at their own discretion in order to maximize the investment return on the Funds' investments. Because of the Company's inability to choose to hold securities that have experienced unrealized losses until recovery of their value, all unrealized losses incurred during 2006 and 2007, prior to the adoption of SFAS No. 159, were considered other-than-temporary impairments under SFAS No. 115.

The adoption of SFAS No. 159 had no impact on the results of operations, cash flows, or financial condition of the Company. For all periods presented, all gains and losses, whether realized, unrealized, or identified as other-than-temporary, have been and will continue to be recorded in the regulatory liability for asset retirement obligations in the balance sheets and are not included in net income or other comprehensive income. Fair value adjustments, realized gains, and other-than-temporary impairment losses are determined on a specific identification basis.

At December 31, 2008, investment securities in the Funds totaled $459.1 million consisting of equity securities of $261.4 million, debt securities of $187.3 million, and $10.4 million of other securities. These amounts exclude receivables related to investment income and pending investment sales, and payables related to pending investment purchases.

At December 31, 2007, investment securities in the Funds totaled $589.0 million consisting of equity securities of $402.4 million, debt securities of $171.8 million, and $14.8 million of other securities. Unrealized gains were $125.5 million for equity securities and $4.8 million for debt securities. Other-than-temporary impairments were $(12.2) million for equity securities and $(1.8) million for debt securities.

Sales of the securities held in the Funds resulted in cash proceeds of $412.2 million, $441.4 million, and $457.4 million in 2008, 2007, and 2006, respectively, all of which were re-invested. For 2008, fair value reductions, including reinvested interest and dividends, were $(143.9) million, of which $(151.0) million related to securities held in the Funds at December 31, 2008. Realized gains and other-than-temporary impairment losses were $43.7 million and $(39.1) million, respectively, in 2007 and $17.8 million and $(12.1) million, respectively, in 2006. While the investment securities held in the Funds are reported as trading securities from the perspective of SFAS No. 115, the Funds continue to be managed with a long-term focus. Accordingly, all purchases and sales within the Funds are presented separately in the statements of cash flows as investing cash flows, consistent with the nature of and purpose for which the securities were acquired.

Amounts previously recorded in internal reserves are being transferred into the external trust funds over periods approved by the Georgia PSC. The NRC's minimum external funding requirements are based on a generic estimate of the cost to decommission only the radioactive portions of a nuclear unit based on the size and type of reactor. The Company has filed plans with the NRC designed to ensure that, over time, the deposits and earnings of the external trust funds will provide the minimum funding amounts prescribed by the NRC.

Site study cost is the estimate to decommission a specific facility as of the site study year. The estimated costs of decommissioning are based on the most current study performed in 2006. The site study costs and accumulated provisions for decommissioning as of December 31, 2008 based on the Company's ownership interests were as follows:

	Plant Hatch	Plant Vogtle
Decommissioning periods:		
Beginning year	2034	2027
Completion year	2061	2051
Site study costs:	*(in millions)*	
Radiated structures	$ 544	$ 507
Non-radiated structures	46	67
Total site study costs	$ 590	$ 574
Accumulated provision	$ 280	$ 168

The decommissioning cost estimates are based on prompt dismantlement and removal of the plant from service. The actual decommissioning costs may vary from these estimates because of changes in the assumed date of decommissioning, changes in NRC requirements, or changes in the assumptions used in making these estimates.

For ratemaking purposes, the Company's decommissioning costs are based on the NRC generic estimate to decommission the radioactive portion of the facilities. Under the 2004 Retail Rate Plan, the annual decommissioning costs for ratemaking were $7 million for Plant Vogtle for 2006 and 2007. Under the 2007 Retail Rate Plan, effective for the years 2008 through 2010, the annual decommissioning cost for ratemaking is $3 million for Plant Vogtle. Based on estimates approved in the 2007 Retail Rate Plan, the Company projected the external trust funds for Plant Hatch would be adequate to meet the decommissioning obligations with no further contributions. The NRC estimates are $495 million and $334 million for Plants Hatch and Vogtle, respectively. Significant assumptions used to determine the costs for ratemaking include an estimated inflation rate of 2.9% and an estimated trust earnings rate of 4.9%. Another significant assumption was that the operating licenses for Plant Vogtle would remain at 40 years until a 20-year extension requested by the Company in June 2007 is authorized by the NRC. The Company anticipates the NRC will make a decision regarding the license extension for Plant Vogtle in 2009.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation. The equity component of AFUDC is not included in calculating taxable income. For the years 2008, 2007, and 2006, the average AFUDC rates were 8.2%, 8.4%, and 8.3%, respectively, and AFUDC capitalized was $135.1 million, $96.8 million, and $44.1 million, respectively. AFUDC and interest capitalized, net of taxes were 13.3%, 10.3%, and 5.0% of net income after dividends on preferred and preference stock for 2008, 2007, and 2006, respectively.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Storm Damage Reserve

The Company maintains a reserve for property damage to cover the cost of damages from major storms to its transmission and distribution lines and the cost of uninsured damages to its generation facilities and other property as mandated by the Georgia PSC. Under the 2004 Retail Rate Plan, the Company accrued $6.6 million annually that was recoverable through base rates. Effective

January 1, 2008, the Company is accruing $21.4 million annually under the 2007 Retail Rate Plan. The Company expects the Georgia PSC to periodically review and adjust, if necessary, the amounts collected in rates for storm damage costs.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average costs of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Georgia PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (categorized in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 10 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Georgia PSC-approved fuel hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 6 under "Financial Instruments" for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2008.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

The Company's financial instruments for which the carrying amount did not equal fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2008	**$ 7,219**	**$ 7,096**
2007	$ 6,066	$ 5,969

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2). See Note 10 for all other items recognized at fair value in the financial statements.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from

transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges and marketable securities, and prior to the adoption of SFAS No.158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158) the minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established certain wholly-owned trusts to issue preferred securities. However, the Company is not considered the primary beneficiary of the trusts. Therefore, the investments in these trusts are reflected as Other Investments, and the related loans from the trusts are reflected as Long-term Debt in the balance sheets. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2009. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds trusts to the extent required by the FERC. For the year ending December 31, 2009, postretirement trust contributions are expected to total approximately $39 million.

The measurement date for plan assets and obligations for 2008 was December 31 while the measurement date for prior years was September 30. Pursuant to SFAS No. 158, the Company was required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ended December 31, 2008. As permitted, the Company adopted the measurement date provisions of SFAS No. 158 effective January 1, 2008 resulting in an increase in long-term liabilities of approximately $10 million and an increase in prepaid pension costs of approximately $10 million.

Pension Plans

The total accumulated benefit obligation for the pension plans was $2.1 billion in 2008 and $2.0 billion in 2007. Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the projected benefit obligations and the fair value of plan assets were as follows:

	2008	2007
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 2,178**	$ 2,136
Service cost	**62**	51
Interest cost	**167**	126
Benefits paid	**(133)**	(98)
Plan amendments	**-**	15
Actuarial (gain) loss	**(36)**	(52)
Balance at end of year	**2,238**	2,178
Change in plan assets		
Fair value of plan assets at beginning of year	**3,073**	2,710
Actual return (loss) on plan assets	**(910)**	456
Employer contributions	**8**	5
Benefits paid	**(133)**	(98)
Fair value of plan assets at end of year	**2,038**	3,073
Funded status at end of year	**(200)**	895
Fourth quarter contributions	**-**	2
(Accrued liability) prepaid pension asset	**$ (200)**	$ 897

At December 31, 2008, the projected benefit obligations for the qualified and non-qualified pension plans were $2.1 billion and $128 million, respectively. All pension plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's pension plan assets as of the end of year, along with the targeted mix of assets, is presented below:

	Target	**2008**	2007
Domestic equity	36%	**34%**	38%
International equity	24	**23**	24
Fixed income	15	**14**	15
Real estate	15	**19**	16
Private equity	10	**10**	7
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's pension plans consist of the following:

	2008	2007
	(in millions)	
Prepaid pension costs	**$ -**	$ 1,027
Other regulatory assets	**642**	64
Current liabilities, other	**(7)**	(7)
Other regulatory liabilities	**-**	(540)
Employee benefit obligations	**(193)**	(123)

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2008 and 2007 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	**Net (Gain) Loss**
Balance at December 31, 2008:	*(in millions)*	
Regulatory asset	**$ 87**	**$ 555**
Total	**$ 87**	**$ 555**
Balance at December 31, 2007:	*(in millions)*	
Regulatory asset	$ 24	$ 40
Regulatory liabilities	81	(621)
Total	$ 105	$ (581)
Estimated amortization in net periodic pension cost in 2009:	*(in millions)*	
Regulatory assets	$ 14	$ 2
Total	$ 14	$ 2

The changes in the balances of regulatory assets and regulatory liabilities related to the defined benefit pension plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in millions)	
Balance at December 31, 2006	$ 56	$ (218)
Net (gain) loss	(1)	(311)
Change in prior service costs	15	-
Reclassification adjustments:		
Amortization of prior service costs	(3)	(11)
Amortization of net gain	(3)	-
Total reclassification adjustments	(6)	(11)
Total change	8	(322)
Balance at December 31, 2007	$ 64	$ (540)
Net (gain) loss	**585**	**554**
Change in prior service costs	**-**	**-**
Reclassification adjustments:		
Amortization of prior service costs	**(4)**	**(14)**
Amortization of net gain	**(3)**	**-**
Total reclassification adjustments	**(7)**	**(14)**
Total change	**578**	**540**
Balance at December 31, 2008	**$ 642**	**$ -**

Components of net periodic pension cost (income) were as follows:

	2008	2007	2006
		(in millions)	
Service cost	**$ 49**	$ 51	$ 53
Interest cost	**134**	126	117
Expected return on plan assets	**(211)**	(195)	(184)
Recognized net (gain) loss	**3**	3	6
Net amortization	**14**	14	8
Net periodic pension cost (income)	**$ (11)**	$ (1)	$ -

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2008, estimated benefit payments were as follows:

	Benefit Payments
	(in millions)
2009	$ 118
2010	124
2011	130
2012	136
2013	143
2014 to 2018	841

Other Postretirement Benefits

Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the accumulated postretirement benefit obligations (APBO) and in the fair value of plan assets were as follows:

	2008	2007
	(in millions)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 798**	$ 807
Service cost	**13**	10
Interest cost	**61**	47
Benefits paid	**(47)**	(35)
Actuarial (gain) loss	**(57)**	(33)
Retiree drug subsidy	**4**	2
Balance at end of year	**772**	798
Change in plan assets		
Fair value of plan assets at beginning of year	**427**	388
Actual return on plan assets	**(131)**	54
Employer contributions	**59**	18
Benefits paid	**(43)**	(33)
Fair value of plan assets at end of year	**312**	427
Funded status at end of year	**(460)**	(371)
Fourth quarter contributions	**-**	31
Accrued liability (recognized in the balance sheets)	**$ (460)**	$ (340)

Other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of year, along with the targeted mix of assets, is presented below:

	Target	**2008**	2007
Domestic equity	43%	**38%**	46%
International equity	21	**21**	23
Fixed income	31	**35**	25
Real estate	3	**4**	4
Private equity	2	**2**	2
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of the following:

	2008	2007
	(in millions)	
Other regulatory assets	**$ 261**	$ 171
Employee benefit obligations	**(460)**	(340)

Presented below are the amounts included in regulatory assets at December 31, 2008 and 2007 related to the other postretirement benefit plans that had not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in millions)	
Balance at December 31, 2008:			
Regulatory assets	**$ 20**	**$ 198**	**$ 43**
Balance at December 31, 2007:			
Regulatory assets	$ 22	$ 94	$ 55
Estimated amortization in net periodic postretirement benefit cost in 2009:			
Regulatory assets	$ 2	$ 4	$ 9

The change in the balance of regulatory assets related to the other postretirement benefit plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 is presented in the following table:

	Regulatory Assets
	(in millions)
Balance at December 31, 2006	$ 254
Net (gain) loss	(64)
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	(9)
Amortization of prior service costs	(2)
Amortization of net gain	(8)
Total reclassification adjustments	(19)
Total change	(83)
Balance at December 31, 2007	$ 171
Net (gain) loss	**110**
Change in prior service costs	**-**
Reclassification adjustments:	
Amortization of transition obligation	**(11)**
Amortization of prior service costs	**(3)**
Amortization of net gain	**(6)**
Total reclassification adjustments	**(20)**
Total change	**90**
Balance at December 31, 2008	**$ 261**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2008	2007	2006
		(in millions)	
Service cost	**$ 10**	$ 10	$ 11
Interest cost	**50**	47	44
Expected return on plan assets	**(30)**	(26)	(25)
Net amortization	**16**	19	22
Net postretirement cost	**$ 46**	$ 50	$ 52

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2008, 2007, and 2006 by approximately $14 million, $14 million, and $16 million, respectively.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in millions)	
2009	$ 45	$ (3)	$ 42
2010	50	(4)	46
2011	54	(5)	49
2012	57	(5)	52
2013	60	(6)	54
2014 to 2018	334	(41)	293

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2005 for the 2006 plan year using a discount rate of 5.50%.

	2008	2007	2006
Discount	**6.75%**	6.30%	6.00%
Annual salary increase	**3.75**	3.75	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.15% for 2009, decreasing gradually to 5.50% through the year 2015 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2008 as follows:

	1 Percent Increase	1 Percent Decrease
	(in millions)	
Benefit obligation	$ 61	$ 61
Service and interest costs	$ 4	$ 4

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution up to 6% of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75% up to 6% of the employee's base salary. Total matching contributions made to the plan for 2008, 2007, and 2006 were $25 million, $24 million, and $21 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S.District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including the Company, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities including the Company's Plants Bowen and Scherer. After Alabama Power was dismissed from the original action for jurisdictional reasons, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The action against the Company has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where it was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates. The ultimate outcome of these matters cannot be determined at this time.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties.

Through 2007, the Company recovered environmental costs through its base rates. Beginning in 2005, such rates included an annual accrual of $5.4 million for environmental remediation. Beginning in January 2008, the Company is recovering environmental remediation costs through a new base rate tariff (see "Retail Regulatory Matters - Rate Plans" herein) that includes an annual accrual of $1.2 million for environmental remediation. Environmental remediation expenditures are charged against the reserve as they are incurred. The annual accrual amount will be reviewed and adjusted in future regulatory proceedings. Under Georgia PSC ratemaking provisions, $22 million had previously been deferred in a regulatory liability account for use in meeting future environmental remediation costs of the Company and was amortized over a three-year period that ended December 31, 2007. As of December 31, 2008, the balance of the environmental remediation liability was $10.1 million.

The Company has been designated or identified as a potentially responsible party (PRP) at sites governed by the Georgia Hazardous Site Response Act and/or by the federal Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), including a large site in Brunswick, Georgia on the CERCLA National Priorities List (NPL). The parties have completed the removal of wastes from the Brunswick site as ordered by the EPA. Additional claims for recovery of natural resource damages at this site or for the assessment and potential cleanup of other sites on the Georgia Hazardous Sites Inventory and the CERCLA NPL are anticipated. The final outcome of these matters cannot now be determined. Based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, management does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

By letter dated September 30, 2008, the EPA advised the Company that it has been designated as a PRP at the Ward Transformer Superfund site located in Raleigh, North Carolina. Numerous other entities have also received notices from the EPA. The Company, along with other named PRPs, will participate in negotiations with the EPA to address cleanup of the site and reimbursement for the EPA's past expenditures related to work performed at the site. The ultimate outcome of this matter will depend upon further environmental assessment and the ultimate number of PRPs and cannot be determined at this time; however, it is not expected to have a material impact on the Company's financial statements.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $5.8 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Intercompany Interchange Contract

The Company's generation fleet is operated under the Intercompany Interchange Contract (IIC), as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the traditional operating companies (including the Company), Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms and Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the

order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan did not have a material impact on the Company's financial statements. In November 2007, Southern Company notified the FERC that the plan had been implemented. On December 12, 2008 the FERC division of audits issued for public comment its final audit report pertaining to compliance implementation and related matters. No comments challenging the audit report's findings were submitted. A decision is now pending from the FERC.

Generation Interconnection Agreements

In November 2004, generator company subsidiaries of Tenaska, Inc. (Tenaska), as counterparties to three previously executed interconnection agreements with subsidiaries of Southern Company, including the Company, filed complaints at the FERC requesting that the FERC modify the agreements and that the Company refund a total of $7.9 million previously paid for interconnection facilities. No other similar complaints are pending with the FERC.

In January 2007, the FERC issued an order granting Tenaska's requested relief. Although the FERC's order required the modification of Tenaska's interconnection agreements, under the provisions of the order the Company determined that no refund was payable to Tenaska. The Company requested rehearing asserting that the FERC retroactively applied a new principle to existing interconnection agreements. Tenaska requested rehearing of FERC's methodology for determining the amount of refunds. The requested rehearings were denied and the Company and Tenaska have appealed the orders to the U.S. Circuit Court for the District of Columbia. The final outcome of this matter cannot now be determined.

Income Tax Matters

The Company's 2005 through 2008 income tax filings for the State of Georgia included state income tax credits for increased activity through Georgia ports. The Company has also filed similar claims for the years 2002 through 2004. The Georgia Department of Revenue has not responded to these claims. In July 2007, the Company filed a complaint in the Superior Court of Fulton County to recover the credits claimed for the years 2002 through 2004. If the Company prevails, these claims could have a significant, and possibly material, positive effect on the Company's net income. If the Company is not successful, payment of the related state tax could have a significant, and possibly material, negative effect on the Company's cash flow. The ultimate outcome of this matter cannot now be determined. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Retail Regulatory Matters

Merger

Effective July 1, 2006, Savannah Electric, which was also a wholly owned subsidiary of Southern Company, was merged into the Company. The Company has accounted for the merger in a manner similar to a pooling of interests, and the Company's financial statements included herein now reflect the merger as though it had occurred on January 1, 2006.

Rate Plans

In December 2007, the Georgia PSC approved the 2007 Retail Rate Plan for the years 2008 through 2010. Retail base rates increased by approximately $99.7 million effective January 1, 2008 to provide for cost recovery of transmission, distribution, generation, and other investment, as well as increased operating costs. In addition, the new ECCR tariff was implemented to recover costs incurred for environmental projects required by state and federal regulations. The ECCR tariff increased rates by approximately $222 million effective January 1, 2008. Under the 2007 Retail Rate Plan, the Company's earnings will continue to be evaluated against a retail return on equity (ROE) range of 10.25% to 12.25%. Two thirds of any earnings above 12.25% will be applied to rate refunds with the remaining one-third applied to the ECCR tariff. The Company agreed that it will not file for a general base rate increase during this period unless its projected retail ROE falls below 10.25%. There were no refunds related to earnings for the year 2008.

In December 2004, the Georgia PSC approved the 2004 Retail Rate Plan for the Company. Under the terms of the 2004 Retail Rate Plan, the Company's earnings were evaluated against a retail ROE range of 10.25% to 12.25%. Two-thirds of any earnings above 12.25% were applied to rate refunds, with the remaining one-third retained by the Company. Retail rates and customer fees increased by approximately $203 million effective January 1, 2005 to cover the higher costs of purchased power, operating and maintenance expenses, environmental compliance, and continued investment in new generation, transmission, and distribution facilities to support growth and ensure reliability. In 2007, the Company refunded 2005 earnings above 12.25% retail ROE. There were no refunds related to earnings for the years 2006 and 2007.

The Company is required to file a general rate case by July 1, 2010, in response to which the Georgia PSC would be expected to determine whether the 2007 Retail Rate Plan should be continued, modified, or discontinued.

Fuel Cost Recovery

The Company has established fuel cost recovery rates approved by the Georgia PSC. In June 2006, the Georgia PSC approved an increase in the Company's total annual billings of approximately $400 million.

In February 2007, the Georgia PSC approved an increase in the Company's total annual billings of approximately $383 million effective March 1, 2007. On May 20, 2008, the Georgia PSC approved an additional increase of approximately $222 million effective June 1, 2008. In compliance with the order, the Company is required to file a new fuel cost recovery rate by March 1, 2009. On February 19, 2009, the Georgia PSC approved the Company's request to delay the filing of that case until March 13, 2009. The new rates are expected to become effective on June 1, 2009. As of December 31, 2008, the Company had a total under recovered fuel cost balance of approximately $764.4 million, of which approximately $223.9 million is not included in current rates.

Fuel cost recovery revenues as recorded on the financial statements are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, a change in the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. Approximately $425.6 million of the under recovered regulatory clause revenues for the Company is included in deferred charges and other assets at December 31, 2008.

Fuel Hedging Program

The Georgia PSC has approved a natural gas, oil procurement, and hedging program that allows the Company to use financial instruments to hedge price and commodity risk associated with these fuels, subject to certain limits in terms of time, volume, dollars, and physical amounts hedged. The costs of the program, including any net losses, are recovered as a fuel cost through the fuel cost recovery clause. Annual net financial gains from the hedging program, through June 30, 2006, were shared with the retail customers receiving 75% and the Company retaining 25% of the total net gains. Effective July 1, 2006, the profit sharing framework related to the fuel hedging program was terminated. The Company realized net losses in 2008, 2007, and 2006 of $1.9 million, $68 million, and $66 million, respectively.

Nuclear Construction

In August 2006, Southern Nuclear, on behalf of the Company, Oglethorpe Power Corporation (OPC), the Municipal Electric Authority of Georgia (MEAG), and the City of Dalton, Georgia (Dalton) (collectively, Owners), filed an application with the NRC for an early site permit relating to two additional nuclear units on the site of Plant Vogtle. See Note 4 for additional information on these co-owners. On March 31, 2008, Southern Nuclear filed an application with the NRC for a COL for the new units.

On April 8, 2008, the Company, acting for itself and as agent for the Owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc. (collectively, Consortium) entered into an engineering, procurement, and construction agreement to design, engineer, procure, construct, and test two AP1000 nuclear units with electric generating capacity of approximately 1,100 megawatts each and related facilities, structures, and improvements at Plant Vogtle (Vogtle 3 and 4 Agreement).

The Vogtle 3 and 4 Agreement is an arrangement whereby the Consortium supplies and constructs the entire facility with the exception of certain items provided by the Owners. Under the terms of the Vogtle 3 and 4 Agreement, the Owners will pay a purchase price that will be subject to certain price escalation and adjustments, adjustments for change orders, and performance bonuses. Each Owner is severally (and not jointly) liable for its proportionate share, based on its ownership interest, of all amounts owed to the Consortium under the Vogtle 3 and 4 Agreement. The Company's proportionate share, based on its current ownership interest, is 45.7%. Under the terms of a separate joint development agreement, the Owners finalized their ownership percentages on July 2, 2008, except for allowed changes, under certain limited circumstances, during the Georgia PSC certification process.

On August 1, 2008, the Company submitted an application for the Georgia PSC to certify the project. Hearings began November 3, 2008 and a final certification decision is expected in March 2009.

If certified by the Georgia PSC and licensed by the NRC, Vogtle Units 3 and 4 are scheduled to be placed in service in 2016 and 2017, respectively. The total plant value to be placed in service will also include financing costs for each of the Owners, the impacts of inflation on costs, and transmission and other costs that are the responsibility of the Owners. The Company's proportionate share of the estimated in-service costs, based on its current ownership interest, is approximately $6.4 billion, subject to adjustments and performance bonuses under the Vogtle 3 and 4 Agreement. In June 2006, the Georgia PSC approved the Company's request to defer for future recovery early site permit and COL costs, of which the Company's portion is estimated to total approximately $53 million. At December 31, 2008 and 2007, approximately $49.0 million and $28.4 million, respectively, were included in deferred charges and other assets. Such costs will be included in construction work in progress if the project is certified by the Georgia PSC.

The Owners and the Consortium have agreed to certain liquidated damages upon the Consortium's failure to comply with the schedule and performance guarantees. The Owners and the Consortium also have agreed to certain bonuses payable to the Consortium for early completion and unit performance. The Consortium's liability to the Owners for schedule and performance liquidated damages and warranty claims is subject to a cap.

The obligations of Westinghouse Electric Company LLC and Stone & Webster, Inc. under the Vogtle 3 and 4 Agreement are guaranteed by Toshiba Corporation and The Shaw Group, Inc., respectively. In the event of certain credit rating downgrades of any Owner, such Owner will be required to provide a letter of credit or other credit enhancement.

The Vogtle 3 and 4 Agreement is subject to certification by the Georgia PSC. In addition, the Owners may terminate the Vogtle 3 and 4 Agreement at any time for their convenience, provided that the Owners will be required to pay certain termination costs and, at certain stages of the work, cancellation fees to the Consortium. The Consortium may terminate the Vogtle 3 and 4 Agreement under certain circumstances, including delays in receipt of the COL or delivery of full notice to proceed, certain Owner suspension or delays of work, action by a governmental authority to permanently stop work, certain breaches of the Vogtle 3 and 4 Agreement by the Owners, Owner insolvency, and certain other events.

Nuclear Fuel Disposal Costs

The Company has contracts with the United States, acting through the U.S. Department of Energy (DOE), which provide for the permanent disposal of spent nuclear fuel. The DOE failed to begin disposing of spent nuclear fuel in 1998 as required by the contracts, and the Company is pursuing legal remedies against the government for breach of contract.

In July 2007, the U.S. Court of Federal Claims awarded the Company approximately $30 million, based on its ownership interests, representing substantially all of the direct costs of the expansion of spent nuclear fuel storage facilities at Plants Hatch and Vogtle from 1998 through 2004. In July 2007, the government filed a motion for reconsideration, which was denied in November 2007. On January 2, 2008, the government filed an appeal, and on February 29, 2008, filed a motion to stay the appeal. On April 1, 2008, the court granted the government's motion to stay the appeal pending the court's decisions in three other similar cases already on appeal. Those cases were decided in August 2008. Based on the rulings in those cases, the appeal is expected to proceed in first quarter 2009.

On April 3, 2008, a second claim against the government was filed for damages incurred after December 31, 2004 (the court-mandated cut-off in the original claim), due to the government's alleged continuing breach of contract. On October 31, 2008, the court denied a similar request by the government to stay this proceeding. The complaint does not contain any specific dollar amount for recovery of damages. Damages will continue to accumulate until the issue is resolved or the storage is provided. No amounts have been recognized in the financial statements as of December 31, 2008 for either claim. The final outcome of these matters cannot be determined at this time, but no material impact on net income is expected as any damage amounts collected from the government are expected to be returned to customers.

Sufficient pool storage capacity for spent fuel is available at Plant Vogtle to maintain full-core discharge capability for both units into 2014. Expanded wet storage capacity and construction of an on-site dry storage facility at Plant Vogtle is expected to begin in sufficient time to maintain pool full-core discharge capability. At Plant Hatch, an on-site dry storage facility is operational and can be expanded to accommodate spent fuel through the expected life of the plant.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own equally all of the outstanding capital stock of SEGCO which owns electric generating units with a total rated capacity of 1,020 megawatts, as well as associated transmission facilities. The capacity of the units has been sold equally to the Company and Alabama Power under a contract which, in substance, requires payments sufficient to provide for the operating expenses, taxes, debt service, and return on investment, whether or not SEGCO has any capacity and energy available. The term of the contract extends automatically for two-year periods, subject to either party's right to cancel upon two year's notice. The Company accounts for SEGCO using the equity method.

The Company's share of expenses included in purchased power from affiliates in the statements of income is as follows:

	2008	2007	2006
		(in millions)	
Energy	**$ 86**	$ 66	$ 58
Capacity	**41**	42	38
Total	**$ 127**	$ 108	$ 96

The Company owns undivided interests in Plants Vogtle, Hatch, Scherer, and Wansley in varying amounts jointly with OPC, MEAG, Dalton, Florida Power & Light Company, Jacksonville Electric Authority, and Gulf Power. Under these agreements, the Company has contracted to operate and maintain the plants as agent for the co-owners and is jointly and severally liable for third party claims related to these plants. In addition, the Company jointly owns the Rocky Mountain pumped storage hydroelectric plant with OPC who is the operator of the plant. The Company and Progress Energy Florida, Inc. jointly own a combustion turbine unit (Intercession City) operated by Progress Energy Florida, Inc.

At December 31, 2008 the Company's percentage ownership and investment (exclusive of nuclear fuel) in jointly owned facilities in commercial operation were as follows:

Facility (Type)	**Company Ownership**	**Investment**	**Accumulated Depreciation**
		(in millions)	
Plant Vogtle (nuclear)	45.7%	$ 3,303	$ 1,918
Plant Hatch (nuclear)	50.1	953	521
Plant Wansley (coal)	53.5	552	189
Plant Scherer (coal)			
Units 1 and 2	8.4	117	68
Unit 3	75.0	566	328
Rocky Mountain (pumped storage)	25.4	175	102
Intercession City (combustion-turbine)	33.3	12	3

At December 31, 2008, the portion of total construction work in progress related to Plants Wansley and Scherer was $114 million and $247 million, respectively, primarily for environmental projects.

The Company's proportionate share of its plant operating expenses is included in the corresponding operating expenses in the statements of income and the Company is responsible for providing its own financing.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined income tax returns for the States of Alabama, Georgia, and Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with IRS regulations, each company is jointly and severally liable for the tax liability.

Current and Deferred Income Taxes

The transfer of the Plant McIntosh construction project from Southern Power to the Company in 2005 resulted in a deferred gain to Southern Power for federal income tax purposes. The Company is reimbursing Southern Power for the remaining balance of the related deferred taxes of $4.6 million as it is reflected in Southern Power's future taxable income. Of this amount, $3.8 million is included in Other Deferred Credits and $0.8 million is included in Affiliated Accounts Payable in the balance sheets at December 31, 2008.

The transfer of the Dahlberg, Wansley, and Franklin projects to Southern Power from the Company in 2001 and 2002 also resulted in a deferred gain for federal income tax purposes. Southern Power is reimbursing the Company for the remaining balance of the related deferred taxes of $8.3 million as it is reflected in the Company's future taxable income. Of this amount, $6.7 million is included in Other Deferred Debits and $1.6 million is included in Affiliated Accounts Receivable in the balance sheets at December 31, 2008.

Details of income tax provisions are as follows:

	2008	2007	2006
		(in millions)	
Federal –			
Current	**$ 284**	$ 442	$ 393
Deferred	**155**	(72)	7
	439	370	400
State –			
Current	**32**	54	33
Deferred	**16**	(6)	9
	48	48	42
Total	**$ 487**	$ 418	$ 442

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2008	2007
	(in millions)	
Deferred tax liabilities –		
Accelerated depreciation	**$ 2,554**	$ 2,376
Property basis differences	**594**	568
Employee benefit obligations	**174**	374
Fuel clause under recovery	**311**	281
Premium on reacquired debt	**67**	71
Regulatory assets associated with employee benefit obligations	**349**	123
Asset retirement obligations	**267**	257
Other	**72**	53
Total	**4,388**	4,103
Deferred tax assets –		
Federal effect of state deferred taxes	**189**	160
Employee benefit obligations	**457**	226
Other property basis differences	**127**	130
Other deferred costs	**99**	131
Other comprehensive income	**10**	2
Regulatory liabilities associated with employee benefit obligations	**-**	209
Unbilled fuel revenue	**42**	34
Asset retirement obligations	**267**	257
Environmental capital cost recovery	**52**	-
Other	**21**	35
Total	**1,264**	1,184
Total deferred tax liabilities, net	**3,124**	2,919
Portion included in current liabilities, net	**(60)**	(69)
Accumulated deferred income taxes	**$ 3,064**	$ 2,850

At December 31, 2008, tax-related regulatory assets were $573 million and tax-related regulatory liabilities were $141 million. The assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. The liabilities are attributable to deferred taxes previously recognized at rates higher than current enacted tax law and to unamortized investment tax credits. In accordance with regulatory requirements, deferred investment tax credits are amortized over the life of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $13.0 million annually in 2008, 2007, and 2006. At December 31, 2008, all investment tax credits available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate was as follows:

	2008	2007	2006
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.2**	2.4	2.2
Non-deductible book depreciation	**0.9**	1.1	1.1
AFUDC equity	**(2.4)**	(1.9)	(0.9)
Donations	**-**	(1.7)	-
Other	**(1.1)**	(1.7)	(1.6)
Effective income tax rate	**34.6%**	33.2%	35.8%

The increase in 2008's effective tax rate is primarily the result of a decrease in donations for 2008 as a result of the significant Tallulah Gorge land donation in 2007 combined with an increase in non-taxable AFUDC equity.

In 2007, the Company donated 2,200 acres of land in the Tallulah Gorge State Park to the State of Georgia. The estimated value of this donation along with an increase in non-taxable AFUDC equity and available state tax credits as well as higher federal tax deductions caused a lower effective income tax rate for the year ended 2007, when compared to prior years. For additional information regarding litigation related to state tax credits, see Note 3 under "Income Tax Matters."

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. This increase from 3% in 2006 to 6% in 2007 was one of several factors that increased the Company's 2007 deduction by $18.6 million over the 2006 deduction. The resulting additional tax benefit was $6.5 million. The IRS has not clearly defined a methodology for calculating this deduction. However, the Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction for all previous years to conform to the agreement which resulted in a decrease in the 2008 deduction when compared to the 2007 deduction. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements.

Unrecognized Tax Benefits

FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties. For 2008, the total amount of unrecognized tax benefits increased by $47.9 million, resulting in a balance of $137.1 million as of December 31, 2008.

Changes during the year in unrecognized tax benefits were as follows:

	2008	2007
	(in millions)	
Unrecognized tax benefits at beginning of year	**$ 89.2**	$ 65.0
Tax positions from current periods	**47.0**	20.5
Tax positions from prior periods	**4.6**	3.7
Reductions due to settlements	**(3.7)**	-
Balance at end of year	**$ 137.1**	$ 89.2

The tax positions from current periods relate primarily to the Georgia state tax credits litigation and other miscellaneous uncertain tax positions. The reductions due to settlements relate to the agreement with the IRS regarding the production activities deduction methodology. See Note 3 under "Income Tax Matters" and "Effective Tax Rate" above for additional information.

Impact on the Company's effective tax rate, if recognized, is as follows:

	2008	2007	Change
		(in millions)	
Tax positions impacting the effective tax rate	$ 134.2	$ 86.1	$ 48.1
Tax positions not impacting the effective tax rate	2.9	3.1	(0.2)
Balance of unrecognized tax benefits	$ 137.1	$ 89.2	$ 47.9

The tax positions impacting the effective tax rate increase of $48.1 million primarily relate to Georgia state tax credit litigation at the Company. See Note 3 under "Income Tax Matters" for additional information.

Accrued interest for unrecognized tax benefits:

	2008	2007
	(in millions)	
Interest accrued at beginning of year	$ 7.1	$ 2.7
Interest reclassified due to settlements	(0.3)	-
Interest accrued during the year	6.8	4.4
Balance at end of year	$ 13.6	$ 7.1

The Company classifies interest on tax uncertainties as interest expense. Net interest accrued for the year ended December 31, 2008 was $6.5 million. The Company did not accrue any penalties on uncertain tax positions.

The IRS has audited and closed all tax returns prior to 2004. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2002.

Substantially all of the Company's unrecognized tax benefits impacting the effective tax rate are associated with the state income tax credits discussed in Note 3 under "Income Tax Matters." Settlement of this litigation could occur within the next 12 months, which would reduce the balance of the uncertain tax position by these amounts.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes totaling $206 million, which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as "Long-term Debt." The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the respective trusts' payment obligations with respect to these securities. At December 31, 2008, preferred securities of $200 million were outstanding. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Securities Due Within One Year

A summary of the scheduled maturities and redemptions of securities due within one year at December 31 is as follows:

	2008	2007
	(in millions)	
Capital lease	$ 5	$ 4
Senior notes	275	195
Total	$ 280	$ 199

Redemptions and/or maturities through 2013 applicable to total long-term debt are as follows: $280 million in 2009; $254 million in 2010; $414 million in 2011; $205 million in 2012; and $530 million in 2013.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds. The Company has incurred obligations in connection with the sale by public authorities of tax-exempt pollution control revenue bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2008 was $1.9 billion. Proceeds from certain issuances are restricted until the expenditures are incurred.

Senior Notes

The Company issued $1,0 billion aggregate principal amount of unsecured senior notes in 2008. The proceeds of the issuance were used to repay a portion of the Company's short term indebtedness, fund note maturities, and fund the Company's continuous construction program. At December 31, 2008 and 2007, the Company had $4.8 billion and $4.0 billion of senior notes outstanding, respectively. These senior notes are effectively subordinated to all secured debt of the Company, which aggregated $68 million at December 31, 2008. Subsequent to December 31, 2008, the Company issued $500 million of Series 2009A 5.95% Senior Notes due February 2039. The proceeds from the sale of the Series 2009A Senior Notes were used by the Company to repay at maturity $150 million aggregate principal amount of the Company's Series U Floating Rate Senior Notes, to repay a portion of its outstanding short-term indebtedness, and for general corporate purposes.

Bank Term Loans

During 2008, the Company borrowed $300 million under a three-year term loan agreement and $100 million under a short-term loan agreement. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program.

Capital Leases

Assets acquired under capital leases are recorded in the balance sheets as utility plant in service, and the related obligations are classified as long-term debt. At December 31, 2008 and 2007, the Company had a capitalized lease obligation for its corporate headquarters building of $66 million and $69 million, respectively, with an interest rate of 8.0%. For ratemaking purposes, the Georgia PSC has treated the lease as an operating lease and has allowed only the lease payments in cost of service. The difference between the accrued expense and the lease payments allowed for ratemaking purposes has been deferred and is being amortized to expense as ordered by the Georgia PSC. See Note 1 under "Regulatory Assets and Liabilities." At December 31, 2008 and 2007, the Company had capitalized lease obligations of $0.8 million and $1.9 million, respectively, for its vehicles. However, for ratemaking purposes, these obligations are treated as operating leases and, as such, lease payments are charged to expense as incurred. The annual expense incurred for these leases in 2008, 2007, and 2006 was $9.7 million, $9.2 million, and $9.6 million, respectively.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company has shares of its Class A preferred stock, preference stock, and common stock outstanding. The Company's Class A preferred stock ranks senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary

dissolution. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the Class A preferred stock and preference stock are subject to redemption at the option of the Company on or after a specified date (typically 5 or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the stock. In addition, the Company may redeem the outstanding series of the preference stock at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At December 31, 2008, the Company had credit arrangements with banks totaling $1.3 billion, of which $12 million was used to support outstanding letters of credit. Of these facilities, $225 million expire during 2009, with the remaining $1.1 billion expiring in 2012. $40 million of the facilities that expire in 2009 provides the option of converting borrowings into a two-year term loan. The Company expects to renew its facilities, as needed, prior to expiration. The agreements contain stated borrowing rates. All the agreements require payment of commitment fees based on the unused portion of the commitments or the maintenance of compensating balances with the banks. Commitment fees average less than 1/8 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

The credit arrangements contain covenants that limit the ratio of indebtedness to capitalization (each as defined in the arrangements) to 65%. For purposes of these definitions, indebtedness excludes the long-term debt payable to affiliated trusts and, in certain cases, other hybrid securities. In addition, the credit arrangements contain cross default provisions that would trigger an event of default if the Company defaulted on other indebtedness above a specified threshold. At December 31, 2008, the Company was in compliance with all such covenants. None of the arrangements contain material adverse change clauses at the time of borrowings.

The $1.3 billion of unused credit arrangements provides liquidity support to the Company's variable rate pollution control revenue bonds and its commercial paper borrowings. The amount of variable rate pollution control revenue bonds outstanding requiring liquidity support as of December 31, 2008 was $636 million. In addition, the Company borrows under a commercial paper program. The amount of commercial paper outstanding at December 31, 2008, 2007, and 2006 was $256 million, $616 million, and $733 million, respectively. The Company also had $100 million of short-term bank loans outstanding at December 31, 2008. Commercial paper and short-term bank loans are included in notes payable on the balance sheets.

During 2008, the peak amount of short-term debt outstanding was $908 million and the average amount outstanding was $460 million. The average annual interest rate on short-term debt in 2008 was 2.9%.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages a fuel-hedging program as discussed in Note 3 under "Retail Regulatory Matters – Fuel Hedging Program." The Company also enters into hedges of forward electricity sales. At December 31, 2008, the Company had a net $113 million fair value liability of energy-related derivative contracts designated as regulatory hedges in the financial statements. The gains and losses arising from these regulatory hedges are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery mechanism. There was no material ineffectiveness related to energy related derivatives recorded in earnings for any period presented. The Company has energy-related hedges in place up to and including 2012.

The Company also enters into derivatives to hedge exposure to changes in interest rates. Derivatives related to existing variable rate securities or forecasted transactions are accounted for as cash flow hedges. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no material ineffectiveness has been recorded in earnings for any period presented.

At December 31, 2008, the Company had $851 million notional amounts of interest derivatives accounted for as cash flow hedges outstanding with net fair value gains/(losses) as follows:

Notional Amount	Variable Rate Received	Weighted Average Fixed Rate Paid	Hedge Maturity Date	Fair Value Gain (Loss) December 31, 2008
(in millions)				*(in millions)*
Cash Flow Hedges on Existing Debt				
$ 301	SIFMA Index *	2.22%	December 2009	$ (3)
150	3-month LIBOR	2.63%	February 2009	-
300	1-month LIBOR	2.43%	April 2010	(5)
Cash Flow Hedges on Forecasted Debt				
100	3-month LIBOR	4.98%	February 2019	(21)

*Hedged using the Securities Industry and Financial Markets Association Municipal Swap Index (SIFMA) (formerly the Bond Market Association/PSA Municipal Swap Index)

The fair value gains or losses for cash flow hedges are recorded in other comprehensive income and are reclassified into earnings at the same time the hedged items affect earnings. In 2008, 2007, and 2006, the Company settled gains/(losses) totaling approximately $(20) million, $12 million, and $(4) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. The effective portion of these gains/(losses) have been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative. In 2008, the Company also settled an interest derivative early because of counterparty credit issues at a loss of approximately $(2) million. This loss is deferred in other comprehensive income and will be amortized into earnings once the forecasted debt is issued in 2009. Amounts reclassified from other comprehensive income to interest expense were immaterial for all periods presented. For 2009, pre-tax losses of approximately $(14) million are expected to be reclassified from other comprehensive income to interest expense. The Company has interest-related hedges in place through 2019 and has deferred realized gains/(losses) that are being amortized through 2037.

Subsequent to December 31, 2008, the Company settled $100 million of hedges related to the forecasted debt issuance in February 2009 at a loss of approximately $16 million. This loss will be amortized into earnings over 10 years.

All derivative financials instruments are recognized as either assets or liabilities and are measured at fair value. See Note 10 for additional information.

7. COMMITMENTS

Construction Program

The Company currently estimates property additions to be approximately $2.8 billion, $2.6 billion, and $2.6 billion in 2009, 2010, and 2011, respectively. This estimate assumes the Company's current request to include construction work in progress for Plant Vogtle Units 3 and 4 in rates is granted by regulators, beginning in 2011. If not, the estimate will increase by approximately $144 million in 2011. These amounts include $139 million, $114 million, and $105 million in 2009, 2010, and 2011, respectively, for construction expenditures related to contractual purchase commitments for nuclear fuel included under "Fuel Commitments." The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; changes in environmental statutes and regulations; changes in nuclear plants to meet new regulatory requirements; changes in FERC rules and regulations; Georgia PSC approvals; changes in legislation; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program.

Long-Term Service Agreements

The Company has entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the combustion turbines at the Plant McIntosh combined cycle facility. In summary, the LTSA stipulates that

GE will perform all planned inspections on the covered equipment, which includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the contract.

In general, this LTSA is in effect through two major inspection cycles per unit. Scheduled payments to GE, which are subject to price escalation, are made quarterly based on actual operating hours of the respective units. Total payments to GE under this agreement are currently estimated at $183 million over the remaining term of the agreement, which is currently projected to be approximately 10 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company has also entered into an LTSA with GE through 2014 for neutron monitoring system parts and electronics at Plant Hatch. Total remaining payments to GE under this agreement are currently estimated at $9.8 million. The contract contains cancellation provisions at the option of the Company. Payments made to GE prior to the performance of any work are recorded as a prepayment in the balance sheets. Work performed by GE is capitalized or charged to expense as appropriate net of any joint owner billings, based on the nature of the work.

The Company has entered into a LTSA with Mitsubishi Power Systems Americas, Inc. (MPS) for the purpose of providing certain parts and maintenance services for the three combined cycle units under construction at Plant McDonough, which are scheduled to go into service in February 2011, June 2011, and June 2012, respectively. The LTSA stipulates that MPS will perform all planned maintenance on each covered unit which includes the cost of all materials and services. MPS is also obligated to cover costs of unplanned maintenance on the gas turbines subject to limits specified in the LTSA. This LTSA will begin in 2011 and is in effect through two major inspection cycles per covered unit. Periodic payments to MPS are to be made quarterly and will also be made based on the scheduled inspections for the respective covered units. Payments to MPS under this agreement, which are subject to price escalation, are currently estimated to be $536.8 million for the term of the agreement which is expected to be between 12 and 13 years. However, the LTSA contains various termination provisions at the option of the Company.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has begun construction of flue gas desulfurization projects and has entered into various long-term commitments for the procurement of limestone to be used in such equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 3.6 million tons, equating to approximately $111.7 million through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are $10.3 million in 2009, $19.3 million in 2010, $14.9 million in 2011, $15.3 million in 2012, and $15.7 million in 2013.

Fuel Commitments

To supply a portion of the fuel requirements of its generating plants, the Company has entered into various long-term commitments for the procurement of fossil and nuclear fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2008.

Total estimated minimum long-term obligations at December 31, 2008 were as follows:

	Commitments		
	Natural Gas	Coal	Nuclear Fuel
		(in millions)	
2009	$ 657	$2,497	$ 139
2010	349	2,001	114
2011	282	1,712	105
2012	364	671	108
2013	380	735	91
2014 and thereafter	2,917	1,999	33
Total	$4,949	$9,615	$ 590

Additional commitments for fuel will be required to supply the Company's future needs. Total charges for nuclear fuel included in fuel expense were $77 million, $79 million, and $71 million for the years 2008, 2007, and 2006, respectively.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure they will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Purchased Power Commitments

The Company has commitments regarding a portion of a 5% interest in Plant Vogtle owned by MEAG that are in effect until the latter of the retirement of the plant or the latest stated maturity date of MEAG's bonds issued to finance such ownership interest. The payments for capacity are required whether or not any capacity is available. The energy cost is a function of each unit's variable operating costs. Portions of the capacity payments relate to costs in excess of Plant Vogtle's allowed investment for ratemaking purposes. The present value of these portions at the time of the disallowance was written off. Generally, the cost of such capacity and energy is included in purchased power from non-affiliates in the statements of income. Capacity payments totaled $48 million, $46 million, and $49 million in 2008, 2007, and 2006, respectively. The Company also has entered into other various long-term PPAs. Estimated total long-term obligations under these commitments at December 31, 2008 were as follows:

	Vogtle Capacity Payments	Affiliated PPA	Non-Affiliated PPA
		(in millions)	
2009	$ 55	$ 220	$ 95
2010	54	153	136
2011	51	119	143
2012	46	107	116
2013	21	107	109
2014 and thereafter	114	596	1,476
Total	$ 341	$ 1,302	$ 2,075

Operating Leases

The Company has entered into various operating leases with various terms and expiration dates. Rental expenses related to these operating leases totaled $52 million for 2008, $55 million for 2007, and $53 million for 2006.

At December 31, 2008, estimated minimum lease payments for these noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in millions)	
2009	$ 33	$ 10	$ 43
2010	27	7	34
2011	25	6	31
2012	14	3	17
2013	12	3	15
2014 and thereafter	25	3	28
Total	$ 136	$ 32	$ 168

In addition to the rental commitments above, the Company has obligations upon expiration of certain rail car leases with respect to the residual value of the leased property. These leases expire in 2011 and the Company's maximum obligation is $39.8 million. At the termination of the leases, at the Company's option, the Company may either exercise its purchase option or the property can be sold to

a third party. The Company expects that the fair market value of the leased property would substantially reduce or eliminate the Company's payments under the residual value obligation. A portion of the rail car lease obligations is shared with the joint owners of Plants Scherer and Wansley. A majority of the rental expenses related to the rail car leases are fully recoverable through the fuel cost recovery clause as ordered by the Georgia PSC and the remaining portion is recovered through base rates.

Guarantees

Alabama Power has guaranteed unconditionally the obligation of SEGCO under an installment sale agreement for the purchase of certain pollution control facilities at SEGCO's generating units, pursuant to which $24.5 million principal amount of pollution control revenue bonds are outstanding. Alabama Power has also guaranteed $50 million in senior notes issued by SEGCO. The Company has agreed to reimburse Alabama Power for the pro rata portion of such obligations corresponding to the Company's then proportionate ownership of stock of SEGCO if Alabama Power is called upon to make such payment under its guaranty.

As discussed earlier in this Note under "Operating Leases," the Company has entered into certain residual value guarantees related to rail car leases.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2008, there were 1,744 current and former employees of the Company participating in the stock option plan, and there were 33.2 million shares of Southern Company common stock remaining available for awards under this plan. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted in 2008, 2007, and 2006 were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2008	2007	2006
Expected volatility	13.1%	14.8%	16.9%
Expected term *(in years)*	5.0	5.0	5.0
Interest rate	2.8%	4.6%	4.6%
Dividend yield	4.5%	4.3%	4.4%
Weighted average grant-date fair value	$ 2.37	$ 4.12	$ 4.15

The Company's activity in the stock option plan for 2008 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2007	7,538,109	$30.59
Granted	1,430,140	35.78
Exercised	(961,426)	27.34
Cancelled	(14,387)	34.82
Outstanding at December 31, 2008	7,992,436	$31.90
Exercisable at December 31, 2008	5,308,585	$29.98

The number of stock options vested, and expected to vest in the future, as of December 31, 2008 was not significantly different from the number of stock options outstanding at December 31, 2008 as stated above. At December 31, 2008, the weighted average remaining contractual term for the options outstanding and options exercisable was 6.2 years and 5.0 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $40.8 million and $37.3 million, respectively.

As of December 31, 2008, there was $1.5 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 10 months.

For the years ended December 31, 2008, 2007, and 2006, total compensation cost for stock option awards recognized in income was $4.2 million, $6.0 million, and $5.8 million, respectively, with the related tax benefit also recognized in income of $1.6 million, $2.3 million, and $2.0 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007, and 2006 was $10.6 million, $17.4 million, and $10.3 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $4.1 million, $6.7 million, and $4.0 million, respectively, for the years ended December 31, 2008, 2007, and 2006.

9. NUCLEAR INSURANCE

Under the Price-Anderson Amendments Act (Act), the Company maintains agreements of indemnity with the NRC that, together with private insurance, cover third-party liability arising from any nuclear incident occurring at the Company's Plants Hatch and Vogtle. The Act provides funds up to $12.5 billion for public liability claims that could arise from a single nuclear incident. Each nuclear plant is insured against this liability to a maximum of $300 million by American Nuclear Insurers (ANI), with the remaining coverage provided by a mandatory program of deferred premiums that could be assessed, after a nuclear incident, against all owners of commercial nuclear reactors. The Company could be assessed up to $117.5 million per incident for each licensed reactor it operates but not more than an aggregate of $17.5 million per incident to be paid in a calendar year for each reactor. Such maximum assessment, excluding any applicable state premium taxes, for the Company, based on its ownership and buyback interests, is $237 million, per incident, but not more than an aggregate of $35 million to be paid for each incident in any one year. Both the maximum assessment per reactor and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due no later than October 29, 2013.

The Company is a member of Nuclear Electric Insurance Limited (NEIL), a mutual insurer established to provide property damage insurance in an amount up to $500 million for members' nuclear generating facilities.

Additionally, the Company has policies that currently provide decontamination, excess property insurance, and premature decommissioning coverage up to $2.25 billion for losses in excess of the $500 million primary coverage. This excess insurance is also provided by NEIL.

NEIL also covers the additional costs that would be incurred in obtaining replacement power during a prolonged accidental outage at a member's nuclear plant. Members can purchase this coverage, subject to a deductible waiting period of up to 26 weeks, with a maximum per occurrence per unit limit of $490 million. After the deductible period, weekly indemnity payments would be received until either the unit is operational or until the limit is exhausted in approximately three years. The Company purchases the maximum limit allowed by NEIL, subject to ownership limitations. Each facility has elected a 12-week waiting period.

Under each of the NEIL policies, members are subject to assessments if losses each year exceed the accumulated funds available to the insurer under that policy. The current maximum annual assessments for the Company under the NEIL policies would be $51 million.

Claims resulting from terrorist acts are covered under both the ANI and NEIL policies (subject to normal policy limits). The aggregate, however, that NEIL will pay for all claims resulting from terrorist acts in any 12-month period is $3.2 billion plus such additional amounts NEIL can recover through reinsurance, indemnity, or other sources.

For all on-site property damage insurance policies for commercial nuclear power plants, the NRC requires that the proceeds of such policies shall be dedicated first for the sole purpose of placing the reactor in a safe and stable condition after an accident. Any remaining proceeds are to be applied next toward the costs of decontamination and debris removal operations ordered by the NRC, and any further remaining proceeds are to be paid either to the Company or to its bond trustees as may be appropriate under the policies and applicable trust indentures.

All retrospective assessments, whether generated for liability, property, or replacement power, may be subject to applicable state premium taxes.

10. FAIR VALUE MEASUREMENTS

On January 1, 2008, the Company adopted FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value, and requires additional disclosures about fair value measurements. The criterion that is set forth in SFAS No. 157 is applicable to fair value measurement where it is permitted or required under other accounting pronouncements.

SFAS No. 157 defines fair value as the exit price, which is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement. As a means to illustrate the inputs used, SFAS No. 157 establishes a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

The adoption of SFAS No. 157 has not resulted in any significant changes to the methodologies used for fair value measurement. Primarily all the changes in the fair value of assets and liabilities are recorded in other comprehensive income or regulatory assets and liabilities, and thus the impact on earnings is limited to derivatives that do not qualify for hedge accounting.

The fair value measurements performed on a recurring basis and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

At December 31, 2008:	Level 1	Level 2	Level 3	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 4.7	$ -	$ 4.7
Nuclear decommissioning trusts[(a)]	260.3	198.8	-	459.1
Cash equivalents and restricted cash	146.9	-	-	146.9
Total fair value	$407.2	$203.5	$ -	$610.7
Liabilities:				
Energy-related derivatives	$ -	$117.9	$ -	$117.9
Interest rate derivatives	-	29.3	-	29.3
Total fair value	$ -	$147.2	$ -	$147.2

(a) Excludes receivables related to investment income, pending investment sales, and payables related to pending investment purchases.

Energy-related derivatives and interest rate derivatives primarily consist of over-the-counter contracts. See Note 6 under "Financial Instruments" for additional information. The nuclear decommissioning trust funds are invested in a diversified mix of equity and fixed income securities. See Note 1 under "Nuclear Decommissioning" for additional information. The cash equivalents and restricted cash consist of securities with original maturities of 90 days or less. All of these financial instruments and investments are valued primarily using the market approach.

11. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2008 and 2007 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preferred and Preference Stock
		(in millions)	
March 2008	**$ 1,865**	**$ 325**	**$ 176**
June 2008	**2,111**	**442**	**248**
September 2008	**2,644**	**711**	**402**
December 2008	**1,792**	**182**	**77**
March 2007	$ 1,657	$ 279	$ 131
June 2007	1,844	361	188
September 2007	2,444	688	400
December 2007	1,627	189	117

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2004-2008

Georgia Power Company 2008 Annual Report

	2008	2007	2006	2005	2004
Operating Revenues (in thousands)	**$8,411,552**	$7,571,652	$7,245,644	$7,075,837	$5,727,768
Net Income after Dividends on Preferred and Preference Stock (in thousands)	**$902,927**	$836,136	$787,225	$744,373	$682,793
Cash Dividends on Common Stock (in thousands)	**$721,200**	$689,900	$630,000	$582,800	$588,700
Return on Average Common Equity (percent)	**13.56**	13.50	13.80	14.08	13.87
Total Assets (in thousands)	**$22,315,668**	$20,822,761	$19,308,730	$17,898,445	$16,598,778
Gross Property Additions (in thousands)	**$1,953,448**	$1,862,449	$1,276,889	$958,563	$1,252,197
Capitalization (in thousands):					
Common stock equity	**$6,879,243**	$6,435,420	$5,956,251	$5,452,083	$5,123,276
Preferred and preference stock	**265,957**	265,957	44,991	43,909	58,547
Long-term debt	**7,006,275**	5,937,792	5,211,912	5,365,323	4,916,694
Total (excluding amounts due within one year)	**$14,151,475**	$12,639,169	$11,213,154	$10,861,315	$10,098,517
Capitalization Ratios (percent):					
Common stock equity	**48.6**	50.9	53.1	50.2	50.7
Preferred and preference stock	**1.9**	2.1	0.4	0.4	0.6
Long-term debt	**49.5**	47.0	46.5	49.4	48.7
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Preferred and Preference Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A**	A	A	A	A
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A+**	A+	A+	A+	A+
Customers (year-end):					
Residential	**2,039,503**	2,024,520	1,998,643	1,960,556	1,926,215
Commercial	**295,925**	295,478	294,654	289,009	283,507
Industrial	**8,248**	8,240	8,008	8,290	7,765
Other	**5,566**	4,807	4,371	4,143	4,015
Total	**2,349,242**	2,333,045	2,305,676	2,261,998	2,221,502
Employees (year-end)	**9,337**	9,270	9,278	9,273	9,294

N/A = Not Applicable.

SELECTED FINANCIAL AND OPERATING DATA 2004-2008 (continued)

Georgia Power Company 2008 Annual Report

	2008	2007	2006	2005	2004
Operating Revenues (in thousands):					
Residential	**$ 2,648,176**	$2,442,501	$2,326,190	$2,227,137	$1,900,961
Commercial	**2,917,270**	2,576,058	2,423,568	2,357,077	1,933,004
Industrial	**1,640,407**	1,403,852	1,382,213	1,406,295	1,217,536
Other	**80,492**	75,592	73,649	73,854	67,250
Total retail	**7,286,345**	6,498,003	6,205,620	6,064,363	5,118,751
Wholesale - non-affiliates	**568,797**	537,913	551,731	524,800	251,581
Wholesale - affiliates	**286,219**	277,832	252,556	275,525	172,375
Total revenues from sales of electricity	**8,141,361**	7,313,748	7,009,907	6,864,688	5,542,707
Other revenues	**270,191**	257,904	235,737	211,149	185,061
Total	**$8,411,552**	$7,571,652	$7,245,644	$7,075,837	$5,727,768
Kilowatt-Hour Sales (in thousands):					
Residential	**26,412,131**	26,840,275	26,206,170	25,508,472	24,829,833
Commercial	**33,058,109**	33,056,632	32,112,430	31,334,182	29,553,893
Industrial	**24,163,566**	25,490,035	25,577,006	25,832,265	27,197,843
Other	**670,588**	697,363	660,285	737,343	744,935
Total retail	**84,304,394**	86,084,305	84,555,891	83,412,262	82,326,504
Sales for resale - non-affiliates	**9,756,260**	10,577,969	10,685,456	10,588,891	5,429,911
Sales for resale - affiliates	**3,694,640**	5,191,903	5,463,463	5,033,165	4,925,744
Total	**97,755,294**	101,854,177	100,704,810	99,034,318	92,682,159
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.03**	9.10	8.88	8.73	7.66
Commercial	**8.82**	7.79	7.55	7.52	6.54
Industrial	**6.79**	5.51	5.40	5.44	4.48
Total retail	**8.64**	7.55	7.34	7.27	6.22
Wholesale	**6.36**	5.17	4.98	5.12	4.09
Total sales	**8.33**	7.18	6.96	6.93	5.98
Residential Average Annual Kilowatt-Hour Use Per Customer	**12,969**	13,315	13,216	13,119	13,002
Residential Average Annual Revenue Per Customer	**$1,300**	$1,212	$1,173	$1,145	$995
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**15,995**	15,995	15,995	15,995	14,743
Maximum Peak-Hour Demand (megawatts):					
Winter	**14,221**	13,817	13,528	14,360	13,087
Summer	**17,270**	17,974	17,159	16,925	16,129
Annual Load Factor (percent)	**58.4**	57.5	61.8	59.4	61.0
Plant Availability (percent):					
Fossil-steam	**90.95**	90.8	91.4	90.0	87.1
Nuclear	**89.81**	92.4	90.7	89.3	94.8
Source of Energy Supply (percent):					
Coal	**58.7**	61.5	59.0	60.7	57.6
Nuclear	**14.8**	14.6	14.4	14.5	16.5
Hydro	**0.6**	0.5	0.9	1.9	1.5
Oil and gas	**5.1**	5.5	5.0	3.0	0.2
Purchased power -					
From non-affiliates	**5.1**	3.8	3.8	4.6	6.0
From affiliates	**15.7**	14.1	16.9	15.3	18.2
Total	**100.0**	100.0	100.0	100.0	100.0

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GULF POWER COMPANY

FINANCIAL SECTION

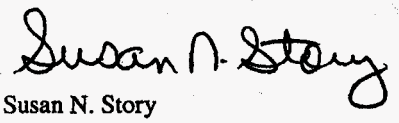
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Gulf Power Company 2008 Annual Report

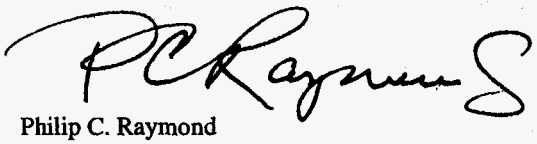
The management of Gulf Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This Annual Report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.



Susan N. Story
President and Chief Executive Officer



Philip C. Raymond
Vice President and Chief Financial Officer

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Gulf Power Company

We have audited the accompanying balance sheets and statements of capitalization of Gulf Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2008 and 2007, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-266 to II-296) present fairly, in all material respects, the financial position of Gulf Power Company at December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

OVERVIEW

Business Activities

Gulf Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain energy sales in the midst of the current economic downturn, and to effectively manage and secure timely recovery of rising costs. These costs include those related to projected long-term demand growth, increasingly stringent environmental standards, fuel prices, and storm restoration costs. Appropriately balancing the need to recover these increasing costs with customer prices will continue to challenge the Company for the foreseeable future.

In July 2006, the Florida Public Service Commission (PSC) extended the storm-recovery surcharge currently being collected by the Company until June 2009. See Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, for additional information.

Key Performance Indicators

In striving to maximize shareholder value while providing cost-effective energy to over 425,000 customers, the Company continues to focus on several key indicators. These indicators include customer satisfaction, plant availability, system reliability, and net income after dividends on preference stock. The Company's financial success is directly tied to the satisfaction of its customers. Key elements of ensuring customer satisfaction include outstanding service, high reliability, and competitive prices. Management uses customer satisfaction surveys and reliability indicators to evaluate the Company's results.

Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The 2008 Peak Season EFOR of 2.47% was better than the target. Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures. The performance for 2008 was at target for these reliability measures. The performance for net income after dividends on preference stock in 2008 was below target. Net income after dividends on preference stock is the primary component of the Company's contribution to Southern Company's earnings per share goal.

The Company's 2008 results compared with its targets for some of these key indicators are reflected in the following chart:

Key Performance Indicator	2008 Target Performance	2008 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR	3.00% or less	2.47%
Net Income	$102 million	$98 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's 2008 net income after dividends on preference stock was $98.3 million, an increase of $14.2 million from the previous year. In 2007, earnings were $84.1 million, an increase of $8.1 million from the previous year. In 2006, earnings were $76.0 million, an increase of $0.8 million from the previous year. The increase in earnings in 2008 was due primarily to higher wholesale revenues from non-affiliates, increased allowance for equity funds used during construction, and a gain on the sale of assets.

The increase in earnings in 2007 was due primarily to increases in retail revenues, earnings on additional investments in environmental controls through the environment cost recovery provision, and related allowance for equity funds used during construction, partially offset by non-fuel operating expenses. The increase in earnings in 2006 was due primarily to higher operating revenues partially offset by higher operating expenses, higher financing costs, and increases in depreciation expense. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year		
	2008	2008	2007	2006
		(in millions)		
Operating revenues	$ 1,387.2	$ 127.4	$ 55.9	$ 120.3
Fuel	635.6	62.2	38.5	119.1
Purchased power	109.4	37.9	(2.3)	(24.6)
Other operations and maintenance	277.5	7.1	10.9	9.8
Depreciation and amortization	84.8	(0.8)	(3.6)	4.2
Taxes other than income taxes	87.2	4.2	3.2	3.4
Total operating expenses	1,194.5	110.6	46.7	111.9
Operating income	192.7	16.8	9.2	8.4
Total other income and (expense)	(34.1)	6.7	1.3	(4.8)
Income taxes	54.1	7.0	1.8	0.3
Net Income	104.5	16.5	8.7	3.3
Dividends on Preference Stock	6.2	2.3	0.6	2.5
Net Income after Dividends on Preference Stock	$ 98.3	$ 14.2	$ 8.1	$ 0.8

Operating Revenues

Operating revenues increased in 2008 when compared to 2007 and 2006. The following table summarizes the changes in operating revenues for the past three years:

	Amount		
	2008	2007	2006
		(in millions)	
Retail – prior year	$ 1,006.3	$ 952.0	$ 864.9
Estimated change in –			
Rates and pricing	6.3	2.5	14.2
Sales growth	(4.6)	5.8	2.5
Weather	3.9	1.2	2.4
Fuel and other cost recovery	108.9	44.8	68.0
Retail – current year	1,120.8	1,006.3	952.0
Wholesale revenues –			
Non-affiliates	97.1	83.5	87.2
Affiliates	107.0	113.2	118.1
Total wholesale revenues	204.1	196.7	205.3
Other operating revenues	62.3	56.8	46.6
Total operating revenues	$ 1,387.2	$ 1,259.8	$ 1,203.9
Percent change	10.1%	4.6%	11.1%

Retail revenues increased $114.4 million, or 11.4%, in 2008, $54.3 million, or 5.7%, in 2007, and $87.2 million, or 10.1%, in 2006. The significant factors driving these changes are shown in the table above.

Revenues associated with changes in rates and pricing include cost recovery provisions for energy conservation costs and environmental compliance costs. Annually, the Company petitions the Florida PSC for recovery of projected costs, including any true-up amount from prior periods, and approved rates are implemented each January. The recovery provisions include related expenses and a return on average net investment. See Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery" for additional information.

Fuel and other cost recovery provisions include fuel expenses, the energy component of purchased power costs, and purchased power capacity costs. Annually, the Company petitions the Florida PSC for recovery of projected fuel and purchased power costs, including any true-up amount from prior periods, and approved rates are implemented each January. Cost recovery provisions also include revenues related to the recovery of storm damage restoration costs. The recovery provisions generally equal the related expenses and have no material effect on net income. See Note 1 to the financial statements under "Revenues" and "Property Damage Reserve" and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Cost Recovery" and "Retail Regulatory Matters – Fuel Cost Recovery" for additional information.

Total wholesale revenues were $204.1 million in 2008, an increase of $7.4 million, or 3.7%, compared to 2007, primarily due to higher capacity revenues associated with new and existing territorial wholesale contracts with non-affiliated companies. Total wholesale revenues were $196.7 million in 2007, a decrease of $8.5 million, or 4.2%, compared to 2006, primarily due to decreased energy sales to affiliates at a lower cost per kilowatt-hour (KWH) supplied by lower-cost generating resources. Total wholesale revenues were $205.2 million in 2006, an increase of $29.5 million, or 16.8%, compared to 2005, primarily due to increased energy sales to affiliates to serve their territorial energy requirements.

Wholesale revenues from sales to non-affiliates will vary depending on the market cost of available energy compared to the cost of the Company and Southern Company system-owned generation, demand for energy with the Southern Company service territory, and availability of Southern Company system generation.

Wholesale revenues from sales to non-affiliates include unit power sales under long-term contracts to other Florida utilities. Wholesale revenues from contracts have both capacity and energy components. Capacity revenues reflect the recovery of fixed costs and a return on investment. Energy is generally sold at variable cost. The capacity and energy components under these unit power sales contracts were as follows:

	2008	2007	2006
		(in thousands)	
Unit power sales –			
Capacity	**$ 22,028**	$ 18,073	$ 21,477
Energy	**33,767**	36,245	34,597
Total	**55,795**	54,318	56,074
Other power sales –			
Capacity and other	**10,890**	2,397	2,436
Energy	**30,380**	26,799	28,632
Total	**41,270**	29,196	31,068
Total non-affiliated	**$ 97,065**	$ 83,514	$ 87,142

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand and the availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). These transactions do not have a significant impact on earnings, since the energy is generally sold at marginal cost and energy purchases are generally offset by revenues through the Company's fuel cost recovery clause.

Other operating revenues increased $5.6 million, or 9.9%, in 2008, primarily due to transmission and distribution network services and other energy services. The increased revenues from other energy services did not have a material impact on earnings since they were generally offset by associated expenses. Other operating revenues increased $10.2 million, or 21.8%, in 2007, primarily due to other energy services and an increase in franchise fees, which were proportional to changes in revenue. Other operating revenues increased $3.6 million, or 8.3%, in 2006, primarily due to an increase in franchise fees, which were proportional to changes in revenue.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2008 and the percent change by year were as follows:

	KWHs	Percent Change		
	2008	2008	2007	2006
	(in millions)			
Residential	**5,349**	**(2.3)%**	0.9%	2.0%
Commercial	**3,961**	**(0.3)**	3.3	2.9
Industrial	**2,210**	**7.9**	(4.1)	(1.1)
Other	**23**	**(5.1)**	4.2	5.1
Total retail	**11,543**	**0.2**	0.8	1.7
Wholesale				
Non-affiliates	**1,817**	**(18.4)**	7.1	(9.4)
Affiliates	**1,871**	**(35.1)**	(1.8)	48.6
Total wholesale	**3,688**	**(27.8)**	1.9	17.4
Total energy sales	**15,231**	**(8.4)**	1.1	6.0

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers.

Residential energy sales decreased 2.3% in 2008, compared to 2007, primarily due to decreased customer usage as a result of a slowing economy, partially offset by more favorable weather. Residential energy sales increased 0.9% in 2007, compared to 2006, primarily due to more favorable weather conditions and customer growth, partially offset by customer response to higher prices. Residential energy sales increased 2.0% in 2006, compared to 2005, primarily due to more favorable weather conditions and customer growth.

The change in commercial energy sales in 2008, compared to 2007, was immaterial. Commercial energy sales increased 3.3% in 2007, compared to 2006, primarily due to more favorable weather conditions and customer growth. Commercial energy sales increased 2.9% in 2006, compared to 2005, primarily due to more favorable weather conditions and customer growth.

Industrial energy sales increased 7.9% in 2008, compared to 2007, primarily due to decreased customer co-generation due to the higher cost of natural gas. Industrial energy sales decreased 4.1% in 2007, compared to 2006, primarily due to a conversion project by a major forest products manufacturer and a production process change by a major petroleum company. Industrial energy sales decreased 1.1% in 2006, compared to 2005, due to reduced demand for and production of building materials and a conversion project by a major paper manufacturer.

Wholesale energy sales to non-affiliates decreased 18.4% in 2008, increased 7.1% in 2007, and decreased 9.4% in 2006, each compared to the prior year primarily as a result of fluctuations in the fuel cost to produce energy sold to non-affiliated utilities under both long-term and short-term contracts. The degree to which oil and natural gas prices, which are the primary fuel sources for these customers, differ from the Company's fuel costs will influence these changes in sales. The fluctuations in sales have a minimal effect on earnings because the energy is generally sold at marginal cost.

Wholesale energy sales to affiliates decreased 35.1% in 2008 and decreased 1.8% in 2007, compared to prior years, primarily due to the availability of lower cost generation resources at affiliated companies. Wholesale energy sales to affiliates increased 48.6% in 2006 compared to 2005, primarily due to increased territorial energy requirements of affiliates.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's electricity generated and purchased were as follows:

	2008	2007	2006
Total generation *(millions of KWHs)*	**14,762**	16,657	16,349
Total purchased power *(millions of KWHs)*	**1,187**	798	876
Sources of generation *(percent)* –			
Coal	**84%**	86%	87%
Gas	**16**	14	13
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.58**	2.86	2.68
Gas	**8.02**	6.91	7.24
Average cost of fuel, generated *(cents per net KWH)*	**4.31**	3.44	3.27
Average cost of purchased power *(cents per net KWH)*	**9.21**	8.96	8.43

Total fuel and purchased power expenses were $745.0 million in 2008, an increase of $100.1 million, or 15.5%, above the prior year costs. The net increase in fuel and purchased power expenses was due to a $130.5 million increase in the average cost of fuel and purchased power as well as a $34.9 million increase in KWHs purchased, offset by a $65.3 million decrease in KWHs generated. Total fuel and purchased power expenses were $644.9 million in 2007, an increase of $36.2 million, or 5.9%, above the prior year costs. The net increase in fuel and purchased power expenses was due to a $32.6 million increase in the average cost of fuel and purchased power as well as a $10.1 million increase in KWHs generated, offset by a $6.5 million decrease in KWHs purchased. Total fuel and purchased power expenses were $608.7 million in 2006, an increase of $94.5 million, or 18.4%, above the prior year costs. The net increase in fuel and purchased power expenses was due to an $82.7 million increase in the average cost of fuel and purchased power as well as a $36.7 million increase in KWHs generated, offset by a $24.9 million decrease in KWHs purchased.

Fuel expense was $635.6 million in 2008, an increase of $62.2 million, or 10.9%, above the prior year costs. This increase was the result of a $127.5 million increase in the average cost of fuel, offset by a $65.3 million decrease related to total KWHs generated. Fuel expense was $573.4 million in 2007, an increase of $38.5 million, or 7.2%, above the prior year costs. This increase was the result of a $28.4 million increase in the average cost of fuel and a $10.1 million increase related to total KWHs generated. Fuel expense was $534.9 million in 2006, an increase of $119.1 million, or 28.7%, above the prior year costs. This increase was the result of an $82.4 million increase in the average cost of fuel and a $36.7 million increase related to total KWHs generated.

Purchased power expense was $109.4 million in 2008, an increase of $37.9 million, or 53.0%, above the prior year costs. This increase was the result of a $34.9 million increase in total KWHs purchased and a $3.0 million increase resulting from the higher average cost per net KWH. Purchased power expense was $71.5 million in 2007, a decrease of $2.3 million, or 3.1%, below the prior year costs. This decrease was the result of a $6.5 million decrease in total KWHs purchased, offset by a $4.2 million increase resulting from the higher average cost per net KWH. Purchased power expense was $73.8 million in 2006, a decrease of $24.6 million, or 25.0%, below the prior year costs. This decrease was the result of a $24.9 million decrease in total KWHs purchased, offset by a $0.3 million increase resulting from the higher average cost per net KWH.

Over the last several years, coal prices have been influenced by a worldwide increase in demand from developing countries, as well as increases in mining and fuel transportation costs. In the first half of 2008, coal prices reached unprecedented high levels primarily due to increased demand following more moderate pricing in 2006 and 2007. Despite these fluctuations, fuel inventories have been adequate and fuel supply markets have been sufficient to meet expected fuel requirements. Demand for natural gas in the United States also increased in 2007 and the first half of 2008. However, natural gas supplies increased in the last half of 2008 as a result of increased production and higher storage levels due in part to weak industrial demand. Both coal and natural gas prices moderated in the second half of 2008 as the result of a recessionary economy.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery provisions. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" herein for additional information.

Other Operations and Maintenance Expenses

In 2008, other operations and maintenance expenses increased $7.1 million, or 2.6%, compared to the prior year primarily due to an $8.2 million increase in scheduled and unscheduled maintenance at generation facilities. In 2007, other operations and maintenance expenses increased $10.9 million, or 4.2%, compared to the prior year primarily due to a $5.0 million increase in other energy services and a $4.3 million increase in severance costs associated with a reorganization. The increased expenses from other energy services did not have a material impact on earnings since they were generally offset by associated revenue. In 2007, the Company offered both voluntary and involuntary severance to a number of employees in connection with a reorganization of certain functions. In 2006, other operations and maintenance expenses increased $9.8 million, or 3.9%, compared to the prior year primarily due to a $4.2 million increase in the recovery of incurred costs for storm damage activity as approved by the Florida PSC, a $1.9 million increase in employee benefit expenses, and a $1.1 million increase in property insurance costs. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein and Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, for additional information.

Depreciation and Amortization

Depreciation and amortization expense decreased $0.8 million, or 0.9%, in 2008 compared to the prior year primarily as a result of a $3.8 million gain on the sale of a building. The decrease was partially offset by an increase of $3.0 million in depreciation due to net additions to generation and distribution facilities. Depreciation and amortization expense decreased $3.6 million, or 4.0%, in 2007 compared to the prior year primarily due to new depreciation rates implemented in January 2007. Depreciation and amortization expense increased $4.2 million, or 4.9%, in 2006 compared to the prior year primarily due to the construction of environmental control projects at Plants Crist and Daniel that were placed in service in 2005.

Taxes Other Than Income Taxes

Taxes other than income taxes increased $4.2 million, or 5.1%, in 2008, compared to the prior year primarily due to a $1.9 million decrease in 2007 related to the resolution of a dispute regarding property taxes in Monroe County, Georgia and a $1.9 million increase in franchise and gross receipt taxes, which were directly related to the increase in retail revenues. Taxes other than income taxes increased $3.2 million, or 4.0%, in 2007, and $3.4 million, or 4.5%, in 2006 primarily due to increases in franchise and gross receipts taxes, which were directly related to the increase in retail revenues.

Allowance for Equity Funds Used During Construction

Allowance for equity funds used during construction (AFUDC) increased $7.6 million, or 319.9%, in 2008 compared to the prior year primarily due to construction of environmental control projects at Plant Crist and Plant Scherer. AFUDC increased $2.0 million, or 554.0%, in 2007 compared to the prior year primarily due to construction of an environmental control project at Plant Crist. AFUDC decreased $0.8 million, or 68.9%, in 2006 compared to the prior year primarily due to the completion of an environmental control project at Plant Crist Unit 7 during 2005. See FUTURE EARNINGS POTENTIAL – "Environmental Matters – Environmental Statutes and Regulations" herein and Note 1 to the financial statements under "Allowance for Funds Used During Construction (AFUDC)" for additional information.

Interest Income

Interest income decreased $2.2 million, or 41%, in 2008, primarily as a result of lower variable interest rates charged against the under recovered fuel balance and a decrease in the property damage reserve balance. Interest income increased $0.1 million, or 2.3%, in 2007, and increased $1.4 million, or 37.4%, in 2006 compared to the prior year primarily due to interest received related to the recovery of financing costs associated with the fuel clause and incurred costs for storm damage activity as approved by the Florida PSC. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Storm Damage Cost Recovery" herein and Note 3 to the financial statements under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information.

Interest Expense, Net of Amounts Capitalized

Interest expense, net of amounts capitalized decreased $1.6 million, or 3.5%, in 2008 compared to the prior year as the result of an increase in capitalization of AFUDC related to the construction of environmental control projects and the redemption of $41.2 million of long-term debt payable to an affiliated trust in 2007. These decreases were offset by the issuance of a $110 million term loan agreement in 2008. Interest expense, net of amounts capitalized increased $0.5 million, or 1.2%, in 2007 compared to the prior year and was not material. Interest expense, net of amounts capitalized increased $3.8 million, or 9.5%, in 2006 compared to the prior year as the result of higher interest rates on variable rate pollution control bonds, increased levels of short-term borrowings at higher interest rates, and the issuance of $60 million in senior notes in August 2005. These increases were partially offset by the maturity of a $100 million bank note in October 2005 and the extinguishment of $30 million aggregate principal amount of first mortgage bonds in 2005.

Other Income (Expense), Net

Other expense, net increased $0.2 million, or 4.9%, in 2008, and increased $0.3 million, or 9.2%, in 2007, compared to prior years and was not material. Other expense, net increased $1.5 million, or 79.1%, in 2006 compared to the prior year primarily as a result of changes in charitable contributions.

Income Taxes

Income taxes increased $7.0 million, or 14.9%, in 2008, compared to the prior year primarily due to higher earnings before income taxes and a decrease in the federal production activities deduction, partially offset by the tax benefit associated with an increase in AFUDC, which is non-taxable. Income taxes increased $1.8 million, or 4.0%, in 2007, and increased $0.3 million, or 0.7%, in 2006 compared to the prior years primarily as a result of higher earnings before income taxes. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Effects of Inflation

The Company is subject to rate regulation based on the recovery of historical costs. When historical costs are included, or when inflation exceeds projected costs used in rate regulation or market-based prices, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, the income tax laws are based on historical costs. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company because of the large investment in utility plant with long economic lives. Conventional accounting for historical cost does not recognize this economic loss or the partially offsetting gain that arises through financing facilities with fixed-money obligations such as long-term debt, preference stock, and preferred securities. Any recognition of inflation by regulatory authorities is reflected in the rate of return allowed in the Company's approved electric rates.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in northwest Florida and to wholesale customers in the Southeast. Prices for electricity provided by the Company to retail customers are set by the Florida PSC under cost-based regulatory principles. Prices for electricity relating to wholesale electricity sales, interconnecting transmission lines, and the exchange of electric power are regulated by the FERC. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend,

in part, upon maintaining energy sales during the current economic downturn, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service area. Recent recessionary conditions have negatively impacted sales growth. The timing and extent of the economic recovery will impact future earnings.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental statutes and regulations are adopted or modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power Company (Alabama Power) and Georgia Power Company (Georgia Power), alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA concurrently issued notices of violation relating to the Company's Plant Crist and a unit at Georgia Power's Plant Scherer that is partially owned by the Company. In early 2000, the EPA filed a motion to amend its complaint to add the allegations in the notice of violation and to add the Company as a defendant. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not refiled. After Alabama Power was dismissed from the original action for jurisdictional reasons, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The action against Georgia Power has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case and the ultimate outcome of these matters cannot be determined at this time.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2008, the Company had invested approximately $718 million in capital projects to comply with these requirements, with annual totals of $296 million, $124 million, and $46 million for 2008, 2007, and 2006, respectively. The Company expects that capital expenditures to assure compliance with existing and new statutes and regulations will be an additional $335 million, $164 million, and $233 million for 2009, 2010, and 2011, respectively. The Company's compliance strategy can be affected by changes to existing environmental laws, statutes, and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

The Florida Legislature has adopted legislation that allows a utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. The legislation is discussed in Note 3 to the financial statements under "Retail Regulatory Matters – Environmental Cost Recovery." Substantially all of the costs for the Clean Air Act and other new environmental legislation discussed below are expected to be recovered through the environmental cost recovery clause.

Compliance with any new federal or state legislation or regulations related to global climate change, air quality, combustion byproducts, including, coal ash, or other environmental and health concerns could also significantly affect the Company. Although

new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2008, the Company had spent approximately $508 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently being installed at several plants to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2004, the EPA designated nonattainment areas under an eight-hour ozone standard. No area within the Company's service area was designated as nonattainment under the eight-hour ozone standard. Macon, Georgia, where Plant Scherer is located, was designated as nonattainment under the eight-hour ozone standard. However, the Macon area has since been redesignated as an attainment area by the EPA, and a maintenance plan to address future exceedances of the standard have been approved. On March 12, 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard which could result in designation of new nonattainment areas within the Company's service territory. The EPA is expected to publish those designations in 2010, and require state implementation plans for any nonattainment areas by 2013.

During 2005, the EPA's annual fine particulate matter nonattainment designations became effective for several areas within Georgia. State plans for addressing the nonattainment designations for this standard were due by April 5, 2008 but have not been finalized. These state plans could require further reductions in SO_2 and NO_x emissions from power plants including plants owned in part by the Company.

The EPA issued the final Clean Air Interstate Rule (CAIR) in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including Florida, Georgia, and Mississippi, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating CAIR in its entirety and remanding it to the EPA for further action consistent with its opinion. On December 23, 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit altered its July decision in response to a rehearing petition and remanded CAIR to the EPA without vacatur, thereby leaving CAIR compliance requirements in place while the EPA develops a revised rule. The State of Florida has an EPA-approved plan to implement this rule. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances. The State of Georgia has completed plans to implement CAIR, and has approved a "multi-pollutant rule" that requires plant-specific emission controls on all but the smallest generating units in Georgia, to be installed according to a schedule set forth in the rule. The rule is designed to ensure reductions in emissions of SO_2, NO_x, and mercury in Georgia. The full impact of the court's remand and the outcome of the EPA's future rulemaking in response cannot be determined at this time.

The Clean Air Visibility Rule (CAVR) (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress by 2018 toward the natural conditions goal. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the CAVR allows states to determine that the CAIR satisfies BART requirements for SO_2 and NO_x. Extensive studies were performed for each of the Company's affected units to demonstrate that additional particulate matter controls are not necessary under BART. States have completed or are currently completing implementation plans that contain strategies for BART and any other measures required to achieve the first phase of reasonable progress.

The impacts of the eight-hour ozone nonattainment designations, the fine particulate matter nonattainment designations, and the CAVR on the Company cannot be determined at this time and will depend on the resolution of any pending legal challenges and the development and implementation of rules at the state level.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the continuing and new environmental requirements discussed above. As part of this strategy, the

Company plans to install additional SO_2 and NO_x emission controls within the next several years to ensure continued compliance with applicable air quality requirements.

In March 2005, the EPA published the final Clean Air Mercury Rule (CAMR), a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The final CAMR was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners alleged that the EPA was not authorized to establish a cap-and-trade program for mercury emissions and instead the EPA must establish maximum achievable control technology standards for coal-fired electric utility steam generating units. On February 8, 2008, the court ruled in favor of the petitioners and vacated the CAMR. The Company's overall environmental compliance strategy relies primarily on a combination of SO_2 and NO_x controls to reduce mercury emissions. Any significant changes in the strategy will depend on the outcome of any appeals and/or future federal and state rulemakings. Future rulemakings necessitated by the court's decision could require emission reductions more stringent than those required by the CAMR.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. In January 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to the EPA for revisions. The decision has been appealed to the U.S. Supreme Court. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its financial statements the costs to clean up known sites. Included in this amount are costs associated with remediation of the Company's substation sites. These projects have been approved by the Florida PSC for recovery through the environmental cost recovery clause; therefore, there is no impact to the Company's net income as a result of these liabilities. The Company may be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions and renewable energy standards continue to be strongly considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. The ultimate outcome of these proposals cannot be determined at this time; however, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that will follow from this response may have implications for both new and existing stationary sources, such as power plants. The ultimate outcome of these rulemaking activities cannot be determined at this time; however, as with the current legislative proposals, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In addition, some states are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. On June 25, 2008, Florida's Governor signed comprehensive energy-related legislation that includes authorization for the Florida Department of Environmental Protection to adopt rules for a cap-and-trade regulatory program to address greenhouse gas emissions from electric utilities, conditioned upon their ratification by the legislature no sooner than the 2010 legislative session. This legislation also authorizes the Florida PSC to adopt a renewable portfolio standard for public utilities, subject to legislative ratification. The impact of

this and any similar legislation on the Company will depend on the future development, adoption, legislative ratification, implementation, and potential legal challenges to rules governing greenhouse gas emissions and mandates regarding the use of renewable energy, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2012 timeframe, with a conclusion to this round of negotiations targeted for the end of 2009. The outcome and impact of the international negotiations cannot be determined at this time.

The Company continues to evaluate its future energy and emission profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $0.8 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company, offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

PSC Matters

Fuel Cost Recovery

The Company petitions for fuel cost recovery rates to be approved by the Florida PSC on an annual basis. At December 31, 2008 and 2007, the under recovered balance was $96.7 million and $56.6 million, respectively, primarily due to lower non-territorial sales, increased costs for coal, and a higher percentage of natural gas fired generation. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. If the projected fuel cost over or under recovery exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery factor is being requested.

On July 29, 2008, the Florida PSC approved a request by the Company to increase the fuel cost recovery factor effective with billings beginning September 2008. The remaining portion of the projected under recovered balance is expected to be recovered in 2009. On September 2, 2008, the Company filed its 2009 projected fuel cost recovery filing with the Florida PSC which includes the fuel factors proposed for January 2009 through December 2009. On October 13, 2008, the Company notified the Florida PSC that the updated projected fuel cost under recovery balance at year-end exceeds the 10% threshold, but no adjustment to the fuel factor was requested.

On November 6, 2008, the Florida PSC approved an increase of approximately 12.9% in the fuel factor for retail customers, effective with billings beginning January 2009. The fuel factors are intended to allow the Company to recover its projected 2009 fuel and purchased power costs as well as the 2008 under recovered amounts in 2009. Fuel cost recovery revenues, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changing the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. See Notes 1 and 3 to the financial statements under "Revenues" and "Retail Regulatory Matters - Fuel Cost Recovery," respectively.

Environmental Cost Recovery

In August 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in March 2007 contemplated implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that are scheduled to be implemented in the 2007 through 2011 timeframe. On September 18, 2008, the Company filed an update to the plan, which was approved by the Florida PSC on November 4, 2008. The Florida PSC acknowledged that the costs associated with the Company's CAIR/CAMR/CAVR compliance plan are clearly eligible for recovery through the environmental cost recovery clause. See FINANCIAL CONDITION AND LIQUIDITY - "Capital Requirements and Contractual Obligations" herein, Note 3 to the financial statements under "Retail Regulatory Matters - Environmental Cost Recovery," and Note 7 to the financial statements under "Construction Program" for additional information.

Storm Damage Cost Recovery

Under authority granted by the Florida PSC, the Company maintains a reserve for property damage to cover the cost of uninsured damages from major storms to its transmission and distribution facilities, generation facilities, and other property. Funds collected by the Company related to the storm-recovery costs associated with previous hurricanes had been fully recovered by August 31, 2008. Funds collected by the Company through its storm-recovery surcharge are now being credited to the property reserve and will continue through June 2009 when the approved surcharge ends. As of December 31, 2008, the balance in the Company's property damage reserve totaled approximately $9.8 million, which is included in deferred liabilities in the balance sheets.

See Notes 1 and 3 to the financial statements under "Property Damage Reserve" and "Retail Regulatory Matters – Storm Damage Cost Recovery," respectively, for additional information.

Income Tax Matters

Legislation

On February 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA include an extension of bonus depreciation and multiple renewable energy incentives. These incentives could have a significant impact on the Company's future cash flow and net income. Additionally, the ARRA includes programs for renewable energy, transmission and smart grid enhancement, fossil energy and research, and energy efficiency and conservation. The ultimate impact cannot be determined at this time.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the Section 199 (production activities deduction) of the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The Internal Revenue Service (IRS) has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction to conform to the agreement. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Other Matters

In 2004, Georgia Power and the Company entered into power purchase agreements (PPAs) with Florida Power & Light Company (FP&L) and Progress Energy Florida. Under the agreements, Georgia Power and the Company will provide FP&L and Progress Energy Florida with 165 megawatts and 74 megawatts, respectively, of capacity annually from the jointly owned Plant Scherer Unit 3 for the period from June 2010 through December 2015. The contracts provide for fixed capacity payments and variable energy payments based on actual energy delivered. The Florida PSC approved the contracts in 2005.

Also in 2004, Georgia Power and the Company entered into a PPA with Flint Electric Membership Corporation. Under the agreement, Georgia Power and the Company will provide Flint Electric Membership Corporation with 75 megawatts of capacity annually from the jointly owned Plant Scherer Unit 3 for the period from June 2010 through December 2019. The contract provides for fixed capacity payments and variable energy payments based on actual energy delivered.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Florida PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with generally accepted accounting principles, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or state revenue department interpretations of existing regulations.
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of new or existing matters through the legislative process, the court systems, the IRS, the FERC, or the EPA.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, and power delivery volume and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2008. Throughout the recent turmoil in the financial markets, the Company has maintained adequate access to capital without drawing on any of its bank credit arrangements used to support its commercial paper programs and variable rate pollution control revenue bonds. The Company has continued to issue commercial paper at reasonable rates. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. No material changes in bank credit arrangements have occurred, although market rates for committed credit have increased and the Company may be subject to higher costs as its existing facilities are replaced or renewed. The Company's interest cost for short-term debt has decreased as market short-term interest rates have declined. The ultimate impact on future financing costs as a result of the financial turmoil cannot be determined at this time. The Company experienced no material counterparty credit losses as a result of the turmoil in the financial markets. See "Sources of Capital" and "Financing Activities" herein for additional information.

The Company's investments in pension trust funds declined in value as of December 31, 2008. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time.

Net cash flow from operating activities totaled $147.9 million, $217.0 million, and $143.4 million for 2008, 2007, and 2006, respectively. The $69.1 million decrease in net cash flows from operating activities in 2008 was due primarily to a $61.0 million increase in cash used for the under recovered regulatory clause related to fuel. The $73.6 million increase in net cash flows from operating activities in 2007 was due primarily to increased cash inflows for fuel cost recovery. The $9.3 million decrease in net cash flows from operating activities in 2006 was due primarily to increased payments related to income taxes and fuel. Net cash flow used by investing activities totaled $348.7 million, $239.3 million, and $164.4 million for 2008, 2007, and 2006, respectively. The increases in cash flows used by investing activities were primarily due to gross property additions to utility plant of $390.7 million, $239.3 million, and $147.1 million for 2008, 2007, and 2006, respectively. Funds for the Company's property additions were provided by operating activities, capital contributions, and other financing activities. Net cash flow from financing activities totaled $198.8 million, $20.2 million, and $24.7 million for 2008, 2007, and 2006, respectively. The $178.6 million increase in net cash flows from financing activities in 2008 was due primarily to the issuance of $110 million in long-term debt and $50 million in short-term debt, and a $49.1 million change in commercial paper cash flows in 2008. The increase was partially offset by the issuance of $85 million in senior notes in 2007. The $4.5 million decrease in net cash flows from financing activities in 2007 was due primarily to a $105.6 million change in commercial paper cash flows and a $25.0 million decrease in senior note proceeds. These decreases were partially offset by the issuance of $80 million in common stock and $45 million in preference stock in 2007. The $77.4 million increase in net cash flows from financing activities in 2006 was due primarily to a $50.0 million increase in senior note proceeds and the redemption of $100.0 million in long-term debt in 2005. These increases were partially offset by the issuance of $55.0 million in preference stock in 2005 and the redemption of $30.9 million of long-term debt payable to affiliated trusts in 2006. See the statements of cash flows for additional information.

Significant balance sheet changes in 2008 included a net increase of $308.2 million in property, plant, and equipment, primarily related to environmental control projects, the issuance of $110 million in long-term debt and $50 million in short-term debt, a $40.1 million increase in under recovered regulatory clause revenues related to fuel, and a $31.0 million change in energy-related derivative contracts. Other significant balance sheet changes which are primarily attributable to the decline in market value of the Company's pension trust fund include a decrease of $107.2 million in prepaid pension costs, an increase of $73.3 million in other deferred regulatory assets, and a decrease of $54.1 million in other deferred regulatory liabilities.

The Company's ratio of common equity to total capitalization, including short-term debt, was 42.9% in 2008, 45.3% in 2007, and 42.1% in 2006. See Note 6 to the financial statements for additional information.

The Company has received investment grade credit ratings from the major rating agencies with respect to its debt and preference stock. See "SELECTED FINANCIAL AND OPERATING DATA" for additional information regarding the Company's security ratings.

Sources of Capital

The Company plans to obtain the funds required for construction and other purposes from sources similar to those used in the past, which were primarily from operating cash flows, securities issuances, term loans, and short-term indebtedness. However, the type and timing of any future financings, if needed, will depend on market conditions, regulatory approval, and other factors.

Security issuances are subject to regulatory approval by the Florida PSC pursuant to its rules and regulations. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the Florida PSC, as well as the amounts, if any, registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

The Company's current liabilities frequently exceed current assets because of the continued use of short-term debt as a funding source to meet cash needs which can fluctuate significantly due to the seasonality of the business. To meet short-term cash needs and contingencies, the Company has various internal and external sources of liquidity. At December 31, 2008, the Company had approximately $3.4 million of cash and cash equivalents, along with $120 million of unused committed lines of credit with banks to meet its short-term cash needs. Of these bank credit arrangements, $120 million will expire in 2009 and $90 million contain provisions allowing one-year term loans executable at expiration. Subsequent to December 31, 2008, the Company obtained an additional $20 million of committed credit, which expires in 2009. The Company plans to renew these lines of credit during 2009 prior to their expiration. In addition, the Company has substantial cash flow from operating activities and access to the capital markets including a commercial paper program to meet liquidity needs. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper and extendible commercial notes at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from such issuances for the benefit of any other traditional operating company. There is no cross affiliate credit support. At December 31, 2008, the Company had $89.9 million of commercial paper outstanding. In addition, the Company had a $50 million short-term bank loan outstanding and $8.3 million in notes payable outstanding related to other energy services contracts.

Financing Activities

In 2008, the Company borrowed $110 million under a three-year term loan agreement and $50 million under a short-term loan agreement. Proceeds were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes, including Gulf Power's continuous construction activities. Interest rate hedges of $80 million were settled related to issuance of senior debt at a loss of approximately $5 million.

In the first and second quarters of 2008, the Company converted its entire $141 million of obligations related to auction rate pollution control revenue bonds from auction rate modes to other interest rate modes. Approximately $75 million of the auction rate pollution control revenue bonds were converted to fixed interest rate modes and approximately $66 million were converted to variable rate modes.

During the fourth quarter of 2008, the Company converted $66 million in obligations related to variable rate pollution control revenue bonds to a fixed interest rate mode, eliminating the committed credit backup requirement for these bonds. Of this amount, the Company purchased from investors approximately $37 million of variable rate pollution control revenue bonds that were subject to mandatory tender, all of which were subsequently remarketed at a fixed rate.

On January 22, 2009, the Company issued to Southern Company 1,350,000 shares of the Company's common stock, without par value, and realized proceeds of $135 million. The proceeds were used to repay a portion of the Company's short-term debt and for other general corporate purposes.

In addition to any financings that may be necessary to meet capital requirements, contractual obligations, and storm-recovery, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel transportation and storage, emissions allowances and energy price risk management. At December 31, 2008, the maximum potential collateral requirements under these contracts at a BBB- and/or Baa3 rating were approximately $49 million. At December 31, 2008, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $205 million. Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

The Company's market risk exposures relative to interest rate changes have not changed materially compared with the December 31, 2007 reporting period. Since a significant portion of outstanding indebtedness is at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect exposures on existing indebtedness in the near term. However, the impact on future financing costs cannot now be determined.

Due to cost-based rate regulation, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and risk management practices. Company policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques including but not limited to market valuation, value at risk, stress testing, and sensitivity analysis.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market and, to a lesser extent, into financial hedge contracts for natural gas purchases. The Company has implemented a fuel-hedging program per the guidelines of the Florida PSC.

The weighted average interest rate on $114 million variable rate long-term debt at January 1, 2009 was 1.62%. If the Company sustained a 100 basis point change in interest rates for all variable rate long-term debt, the change would affect annualized interest expense by approximately $1 million at January 1, 2009. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

The changes in fair value of energy-related derivative contracts were as follows at December 31:

	2008 Changes	2007 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ (0.2)**	$ (7.1)
Contracts realized or settled	**(8.0)**	6.6
Current period changes[a]	**(23.0)**	0.3
Contracts outstanding at the end of the period, assets (liabilities), net	**$ (31.2)**	$ (0.2)

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The decrease in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2008 was $31.0 million, substantially all of which is due to natural gas positions. This change is attributable to both the volume and prices of natural gas. At December 31, 2008, the Company had a net hedge volume of 14.2 billion cubic feet (Bcf) with a weighted average contract cost approximately $2.24 per million British thermal units (mmBtu) above market prices, and 7.5 Bcf at December 31, 2007 with a weighted average contract cost approximately $0.03 per mmBtu above market prices. Natural gas hedges are recovered through the fuel cost recovery clause.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/ (liabilities) as follows:

	2008	2007
	(in millions)	
Regulatory hedges	**$ (31.2)**	$ (0.2)
Cash flow hedges	**-**	-
Non-accounting hedges	**-**	-
Total fair value	**$ (31.2)**	$ (0.2)

Energy-related derivative contracts designated as regulatory hedges are related to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. Certain other gains and losses on energy-related derivatives, designated as cash flow hedges, are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred.

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented.

The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

	December 31, 2008 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	**$ -**	**$ -**	**$ -**	**$ -**
Level 2	**(31.2)**	**(25.9)**	**(5.3)**	**-**
Level 3	**-**	**-**	**-**	**-**
Fair value of contracts outstanding at end of period	**$ (31.2)**	**$ (25.9)**	**$ (5.3)**	**$ -**

As part of the adoption of FASB Statement No. 157, "Fair Value Measurements" to increase consistency and comparability in fair value measurements and related disclosures, the table above now uses the three-tier fair value hierarchy, as discussed in Note 9 to the financial statements, as opposed to the previously used descriptions "actively quoted," "external sources," and "models and other methods." The three-tier fair value hierarchy focuses on the fair value of the contract itself, whereas the previous descriptions focused on the source of the inputs. Because the Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, the valuations of those contracts now appear in Level 2; previously they were shown as "actively quoted."

The Company is exposed to market price risk in the event of nonperformance by counterparties to the derivative energy contracts. The Company's practice is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $478 million in 2009, $337 million in 2010, and $400 million in 2011. Environmental expenditures included in these estimated amounts are $335 million in 2009, $164 million in 2010, and $233 million in 2011. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; storm impacts; changes in environmental statutes and regulations; changes in FERC rules and regulations; Florida PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

The Company plans to construct a new landfill gas to energy generation facility. Construction of new transmission and distribution facilities and capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, is ongoing.

As discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC and the Florida PSC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preference stock dividends, leases, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2009	2010-2011	2012-2013	After 2013	Total
			(in thousands)		
Long-term debt[a] –					
Principal	$ -	$ 110,000	$ 60,000	$ 686,255	$ 856,255
Interest	40,864	81,728	78,110	471,610	672,312
Energy-related derivative obligations[b]	26,928	5,305	-	-	32,233
Preference stock dividends[c]	6,203	12,405	12,405	-	31,013
Operating leases	5,549	9,064	2,352	2,223	19,188
Purchase commitments[d] –					
Capital[e]	477,618	737,292	-	-	1,214,910
Limestone[f]	-	11,540	12,125	40,182	63,847
Coal	282,370	182,486	-	-	464,856
Natural gas[g]	112,618	128,320	40,276	151,016	432,230
Purchased power	23,007	53,672	53,997	3,918	134,594
Long-term service agreements[h]	7,088	14,903	14,552	25,954	62,497
Postretirement benefits trust[i]	34	68	-	-	102
Total	$ 982,279	$ 1,346,783	$ 273,817	$ 1,381,158	$ 3,984,037

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2009, as reflected in the statements of capitalization.

(b) For additional information, see Notes 1 and 6 to the financial statements.

(c) Preference stock does not mature; therefore, amounts are provided for the next five years only.

(d) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $277 million, $270 million, and $260 million, respectively.

(e) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program.

(f) As part of the Company's program to reduce sulfur dioxide emissions from its coal plants, the Company has begun construction of flue gas desulfurization projects and has entered into various long-term commitments for the procurement of limestone to be used in such equipment.

(g) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2008.

(h) Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts postretirement trust contributions over a three-year period. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time. Therefore, no amounts related to the pension trust fund are included in the table. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2008 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, retail rates, storm damage cost recovery and repairs, fuel cost recovery and other rate actions, environmental regulations and expenditures, earnings growth, access to sources of capital, projections for postretirement benefit trust contributions, financing activities, completion of construction projects, impacts of adoption of new accounting rules, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings or inquiries, including FERC matters and the EPA civil actions against the Company;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population, and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

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STATEMENTS OF INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Gulf Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Revenues:			
Retail revenues	**$1,120,766**	$1,006,329	$952,038
Wholesale revenues --			
Non-affiliates	**97,065**	83,514	87,142
Affiliates	**106,989**	113,178	118,097
Other revenues	**62,383**	56,787	46,637
Total operating revenues	**1,387,203**	1,259,808	1,203,914
Operating Expenses:			
Fuel	**635,634**	573,354	534,921
Purchased power --			
Non-affiliates	**29,590**	11,994	16,288
Affiliates	**79,750**	59,499	57,536
Other operations and maintenance	**277,478**	270,440	259,519
Depreciation and amortization	**84,815**	85,613	89,170
Taxes other than income taxes	**87,247**	82,992	79,808
Total operating expenses	**1,194,514**	1,083,892	1,037,242
Operating Income	**192,689**	175,916	166,672
Other Income and (Expense):			
Allowance for equity funds used during construction	**9,969**	2,374	363
Interest income	**3,155**	5,348	5,228
Interest expense, net of amounts capitalized	**(43,098)**	(44,680)	(44,133)
Other income (expense), net	**(4,064)**	(3,876)	(3,548)
Total other income and (expense)	**(34,038)**	(40,834)	(42,090)
Earnings Before Income Taxes	**158,651**	135,082	124,582
Income taxes	**54,103**	47,083	45,293
Net Income	**104,548**	87,999	79,289
Dividends on Preference Stock	**6,203**	3,881	3,300
Net Income After Dividends on Preference Stock	**$ 98,345**	$ 84,118	$ 75,989

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007, and 2006
Gulf Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Activities:			
Net income	**$104,548**	$ 87,999	$ 79,289
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**93,606**	90,694	94,466
Deferred income taxes	**23,949**	(10,818)	1,170
Allowance for equity funds used during construction	**(9,969)**	(2,374)	(363)
Pension, postretirement, and other employee benefits	**1,585**	6,062	3,319
Stock based compensation expense	**765**	1,141	1,005
Tax benefit of stock options	**215**	344	211
Hedge settlements	**(5,220)**	3,030	(5,399)
Other, net	**(5,150)**	(7,074)	7,294
Changes in certain current assets and liabilities --			
Receivables	**(49,885)**	10,302	(36,795)
Fossil fuel stock	**(36,765)**	5,025	(31,297)
Materials and supplies	**8,927**	(2,625)	(2,330)
Prepaid income taxes	**(416)**	7,177	(7,060)
Property damage cost recovery	**26,143**	25,103	24,544
Other current assets	**(307)**	(632)	(955)
Accounts payable	**(4,561)**	(555)	13,876
Accrued taxes	**(6,511)**	4,773	(455)
Accrued compensation	**570**	(1,322)	(3,251)
Other current liabilities	**6,418**	732	6,165
Net cash provided from operating activities	**147,942**	216,982	143,434
Investing Activities:			
Property additions	**(377,790)**	(241,538)	(154,377)
Cost of removal net of salvage	**(8,713)**	(9,408)	(4,564)
Construction payables	**37,244**	10,817	3,309
Other	**576**	803	(8,779)
Net cash used for investing activities	**(348,683)**	(239,326)	(164,411)
Financing Activities:			
Increase (decrease) in notes payable, net	**107,438**	(75,821)	30,981
Proceeds --			
Senior notes	**-**	85,000	110,000
Common stock issued to parent	**-**	80,000	-
Preference stock	**-**	45,000	-
Pollution control revenue bonds	**37,000**	-	-
Gross excess tax benefit of stock options	**298**	799	423
Capital contributions from parent company	**75,324**	4,174	26,140
Other long-term debt	**110,000**	-	-
Redemptions --			
Senior notes	**(1,300)**	-	-
Pollution control revenue bonds	**(37,000)**	-	(12,075)
First mortgage bonds	**-**	-	(25,000)
Other long-term debt	-	(41,238)	(30,928)
Payment of preference stock dividends	**(6,057)**	(3,300)	(3,300)
Payment of common stock dividends	**(81,700)**	(74,100)	(70,300)
Other	**(5,167)**	(348)	(1,285)
Net cash provided from financing activities	**198,836**	20,166	24,656
Net Change in Cash and Cash Equivalents	**(1,905)**	(2,178)	3,679
Cash and Cash Equivalents at Beginning of Year	**5,348**	7,526	3,847
Cash and Cash Equivalents at End of Year	**$ 3,443**	$ 5,348	$ 7,526
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $3,973, $1,048, and $160 capitalized, respectively)	**$39,956**	$35,237	$37,297
Income taxes (net of refunds)	**40,176**	39,228	54,533

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2008 and 2007
Gulf Power Company 2008 Annual Report

Assets	2008	2007
	(in thousands)	
Current Assets:		
Cash and cash equivalents	$ 3,443	$ 5,348
Receivables --		
Customer accounts receivable	69,531	63,227
Unbilled revenues	48,742	39,000
Under recovered regulatory clause revenues	98,645	58,435
Other accounts and notes receivable	7,201	7,162
Affiliated companies	8,516	19,377
Accumulated provision for uncollectible accounts	(2,188)	(1,711)
Fossil fuel stock, at average cost	108,129	71,012
Materials and supplies, at average cost	36,836	45,763
Property damage cost recovery	-	18,585
Other regulatory assets	38,907	10,220
Other	25,655	14,878
Total current assets	443,417	351,296
Property, Plant, and Equipment:		
In service	2,785,561	2,678,952
Less accumulated provision for depreciation	971,464	931,968
	1,814,097	1,746,984
Construction work in progress	391,987	150,870
Total property, plant, and equipment	2,206,084	1,897,854
Other Property and Investments	15,918	4,563
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	24,220	17,847
Prepaid pension costs	-	107,151
Other regulatory assets	170,836	97,492
Other	18,550	22,784
Total deferred charges and other assets	213,606	245,274
Total Assets	$2,879,025	$2,498,987

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2008 and 2007
Gulf Power Company 2008 Annual Report

Liabilities and Stockholder's Equity	2008	2007
	(in thousands)	
Current Liabilities:		
Notes payable	**$148,239**	$ 44,625
Accounts payable --		
Affiliated	**50,304**	39,375
Other	**90,381**	56,823
Customer deposits	**28,017**	24,885
Accrued taxes --		
Income taxes	**39,983**	30,026
Other	**11,855**	10,577
Accrued interest	**8,959**	7,698
Accrued compensation	**15,667**	15,096
Other regulatory liabilities	**4,602**	6,027
Liabilities from risk management activities	**26,928**	4,065
Other	**29,047**	27,958
Total current liabilities	**453,982**	267,155
Long-term Debt (See accompanying statements)	**849,265**	740,050
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**254,354**	240,101
Accumulated deferred investment tax credits	**11,255**	12,988
Employee benefit obligations	**97,389**	74,021
Other cost of removal obligations	**180,325**	172,876
Other regulatory liabilities	**28,596**	82,741
Other	**83,769**	79,802
Total deferred credits and other liabilities	**655,688**	662,529
Total Liabilities	**1,958,935**	1,669,734
Preference Stock (See accompanying statements)	**97,998**	97,998
Common Stockholder's Equity (See accompanying statements)	**822,092**	731,255
Total Liabilities and Stockholder's Equity	**$2,879,025**	$2,498,987
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION

At December 31, 2008 and 2007

Gulf Power Company 2008 Annual Report

	2008	2007	2008	2007
		(in thousands)	*(percent of total)*	
Long Term Debt:				
Long-term notes payable --				
4.35% due 2013	**$ 60,000**	$ 60,000		
4.90% to 5.90% due 2014-2044	**528,700**	530,000		
Variable rates (1.645% at 1/1/09) due 2011	**110,000**	-		
Total long-term notes payable	**698,700**	590,000		
Other long-term debt --				
Pollution control revenue bonds --				
2.35% to 6.00% due 2022-2037	**153,625**	13,000		
Variable rate (1.05% at 1/1/09) due 2022-2037	**3,930**	144,555		
Total other long-term debt	**157,555**	157,555		
Unamortized debt discount	**(6,990)**	(7,505)		
Total long-term debt (annual interest requirement -- $40.9 million)	**849,265**	740,050	**48.0%**	47.2%
Preferred and Preference Stock:				
Authorized - 20,000,000 shares--preferred stock				
- 10,000,000 shares--preference stock				
Outstanding - $100 par or stated value -- 6% preference stock	**53,886**	53,886		
-- 6.45% preference stock	**44,112**	44,112		
- 1,000,000 shares (non-cumulative)				
Preference stock				
(annual dividend requirement -- $6.2 million)	**97,998**	97,998	**5.5**	6.2
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized - 20,000,000 shares				
Outstanding - 1,792,717 shares	**118,060**	118,060		
Paid-in capital	**511,547**	435,008		
Retained earnings	**197,417**	181,986		
Accumulated other comprehensive income (loss)	**(4,932)**	(3,799)		
Total common stockholder's equity	**822,092**	731,255	**46.5**	46.6
Total Capitalization	**$1,769,355**	$1,569,303	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2008, 2007, and 2006

Gulf Power Company 2008 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)		
Balance at December 31, 2005	$38,060	$400,815	$166,279	$ (2,810)	$602,344
Net income after dividends on preference stock	-	-	75,989	-	75,989
Capital contributions from parent company	-	27,777	-	-	27,777
Other comprehensive income (loss)	-	-	-	(3,112)	(3,112)
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	1,325	1,325
Cash dividends on common stock	-	-	(70,300)	-	(70,300)
Balance at December 31, 2006	38,060	428,592	171,968	(4,597)	634,023
Net income after dividends on preference stock	-	-	84,118	-	84,118
Issuance of common stock	80,000	-	-	-	80,000
Capital contributions from parent company	-	6,458	-	-	6,458
Other comprehensive income (loss)	-	-	-	798	798
Cash dividends on common stock	-	-	(74,100)	-	(74,100)
Other	-	(42)	-	-	(42)
Balance at December 31, 2007	**118,060**	**435,008**	**181,986**	**(3,799)**	**731,255**
Net income after dividends on preference stock	-	-	**98,345**	-	**98,345**
Capital contributions from parent company	-	**76,539**	-	-	**76,539**
Other comprehensive income (loss)	-	-	-	**(1,133)**	**(1,133)**
Cash dividends on common stock	-	-	**(81,700)**	-	**(81,700)**
Change in benefit plan measurement date	-	-	**(1,214)**	-	**(1,214)**
Balance at December 31, 2008	**$118,060**	**$511,547**	**$197,417**	**$(4,932)**	**$822,092**

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Gulf Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Net income after dividends on preference stock	**$98,345**	$84,118	$75,989
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(1,077), $232, and $(2,082), respectively	**(1,716)**	371	(3,317)
Reclassification adjustment for amounts included in net income, net of tax of $366, $269, and $140, respectively	**583**	427	224
Pension and other postretirement benefit plans:			
Change in additional minimum pension liability, net of tax of $-, $-, and $(13), respectively	-	-	(19)
Total other comprehensive income (loss)	**(1,133)**	798	(3,112)
Comprehensive Income	**$97,212**	$84,916	$72,877

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Gulf Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), the Company, and Mississippi Power Company (Mississippi Power), are vertically integrated utilities providing electric service in four Southeastern states. The Company provides retail service to customers in northwest Florida and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and the subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The equity method is used for subsidiaries in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Reclassifications

Certain prior years' data presented in the financial statements have been reclassified to conform to current year presentation. For presentation purposes, the statements of income for the prior periods presented have been modified within the operating expenses section to combine the line items "Other operations" and "Maintenance" into a single line item entitled "Other operations and maintenance." In addition, the statements of income were modified to report a separate line item for "Allowance for equity funds used during construction" previously included in "Other income and expense, net." In conjunction with such modification, the Company modified its statement of cash flows within the operating activities section to present a separate line item for "Allowance for equity funds used during construction" previously included in "Other, net." The balance sheet at December 31, 2007 was modified to present a separate line for "Liabilities for risk management activities" previously included in "Other." These reclassifications had no effect on total assets, net income, or cash flows.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool operations. Costs for these services amounted to $86 million, $73 million, and $59 million during 2008, 2007, and 2006, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company has agreements with Georgia Power and Mississippi Power under which the Company owns a portion of Plant Scherer and Plant Daniel, respectively. Georgia Power operates Plant Scherer and Mississippi Power operates Plant Daniel. The Company reimbursed Georgia Power $8.1 million, $5.1 million, and $8.0 million, and Mississippi Power $22.8 million, $23.1 million, and $19.7 million in 2008, 2007, and 2006, respectively, for its proportionate share of related expenses. See Note 4 and Note 7 under "Operating Leases" for additional information.

The Company entered into a power purchase agreement (PPA), with Southern Power for a total of approximately 292 megawatts annually from June 2009 through May 2014. The PPA was the result of a competitive request for proposal process initiated by the Company in January 2006 to address the anticipated need for additional capacity beginning in 2009. In May 2007, the Florida PSC issued an order approving the PPA for purpose of cost recovery through the Company's purchased power capacity clause. The PPA with Southern Power was approved by the FERC in July 2007.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. There were no significant services provided or received in 2008, 2007, and 2006.

The traditional operating companies, including the Company, and Southern Power jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

In 2008, the Company sold a turbine rotor assembly and a distance piece component to Southern Power for $9.4 million and $0.7 million, respectively. In 2007, the Company purchased a compressor assembly from Georgia Power and a turbine rotor assembly from Southern Power for $4.0 million and $7.9 million, respectively. The affiliate transactions were made in accordance with FERC and state PSC rules and guidelines. The purchases are included in property, plant, and equipment in the balance sheets.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process. Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2008	2007	Note
		(in thousands)	
Environmental remediation	**$ 66,812**	$ 66,923	(a)
Loss on reacquired debt	**16,248**	17,378	(b)
Vacation pay	**7,991**	7,411	(c)
Deferred charges related to income taxes	**24,220**	17,847	(d)
Fuel-hedging (realized and unrealized) losses	**35,333**	1,834	(e)
Underfunded retiree benefit plans	**81,912**	14,602	(f)
Other assets	**3,360**	1,371	(g)
Under recovered regulatory clause revenues	**96,731**	56,628	(g)
Property damage reserve	**(9,801)**	18,585	(h)
Asset retirement obligations	**(4,531)**	(4, 570)	(d)
Other cost of removal obligations	**(180,325)**	(172,876)	(d)
Deferred income tax credits	**(12,983)**	(15,331)	(d)
Fuel-hedging (realized and unrealized) gains	**(1,071)**	(1,455)	(e)
Over recovered regulatory clause revenues	**(3,295)**	(5,233)	(g)
Other liabilities	**(1,518)**	(1,715)	(g)
Overfunded retiree benefit plans	**-**	(60,464)	(f)
Total assets (liabilities), net	**$ 119,083**	$ (59,065)	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) Recovered through the environmental cost recovery clause when the remediation is performed.

(b) Recovered over the remaining life of the original issue, which may range up to 40 years.

(c) Recorded as earned by employees and recovered as paid, generally within one year.

(d) Asset retirement and removal liabilities are recovered, deferred charges related to income tax assets are recovered, and deferred charges related to income tax liabilities are amortized over the related property lives, which may range up to 65 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.

(e) Fuel-hedging assets and liabilities are recognized over the life of the underlying hedged purchase contracts, which generally do not exceed four years. Upon final settlement, costs are recovered through the fuel cost recovery clause.

(f) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 under "Retirement Benefits."

(g) Recorded and recovered or amortized as approved by the Florida PSC.

(h) Recorded and recovered or amortized as approved by the Florida PSC. Storm cost recovery surcharge ends in June 2009.

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS No. 71, the Company would be required to write off or reclassify to accumulated other comprehensive income related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant assets, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are reflected in rates.

Revenues

Energy and other revenues are recognized as services are provided. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. Wholesale capacity revenues are generally recognized on a levelized basis over the appropriate contract period. The Company's retail electric rates include provisions to adjust billings for fluctuations in fuel costs, the energy component of purchased power costs, and certain other costs. The Company continuously monitors the over or under recovered fuel cost balance in light of the inherent variability in fuel costs. The Company is required to notify the Florida PSC if the projected fuel cost over or under recovery is expected to exceed 10% of the projected fuel revenue applicable for the period and indicate if an adjustment to the fuel cost recovery factor is being requested. The Company has similar retail cost recovery clauses for energy conservation costs, purchased power capacity costs, and environmental compliance costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. Annually, the Company petitions for recovery of projected costs including any true-up amount from prior periods, and approved rates are implemented each January. In November 2008, the Florida PSC approved billing factors for 2009 intended to allow the Company to recover projected 2009 costs as well as refund or collect the 2008 over or under recovered amounts in 2009. See Note 3 under "Regulatory Matters – Fuel Cost Recovery" for additional information.

The Company has a diversified base of customers. No single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction.

The Company's property, plant, and equipment consisted of the following at December 31:

	2008	2007
	(in thousands)	
Generation	**$ 1,445,095**	$ 1,390,635
Transmission	**305,097**	282,408
Distribution	**900,793**	873,642
General	**131,269**	128,704
Plant acquisition adjustment	**3,307**	3,563
Total plant in service	**$ 2,785,561**	$ 2,678,952

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred or performed.

Depreciation and Amortization

Depreciation of the original cost of utility plant in service is provided primarily by using composite straight-line rates, which approximated 3.4% in 2008, 3.4% in 2007, and 3.7% in 2006. Depreciation studies are conducted periodically to update the composite rates. These studies are approved by the Florida PSC. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its original cost, together with the cost of removal, less salvage, is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the balance sheet accounts and a gain or loss is recognized. Minor items of property included in the original cost of the plant are retired when the related property unit is retired.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received an order from the Florida PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability.

The liability recognized to retire long-lived assets primarily relates to the Company's combustion turbines at its Pea Ridge facility, various landfill sites, a barge unloading dock, asbestos removal, ash ponds, and disposal of polychlorinated biphenyls in certain transformers. The Company also has identified retirement obligations related to certain transmission and distribution facilities, certain wireless communication towers, and certain structures authorized by the United States Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under FASB Statement No. 143 "Accounting for Asset Retirement Obligations" and FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Florida PSC, and are reflected in the balance sheets.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2008	2007
	(in thousands)	
Balance beginning of year	**$ 11,942**	$ 12,718
Liabilities incurred	**-**	503
Liabilities settled	**(354)**	(484)
Accretion	**631**	619
Cash flow revisions	**(177)**	(1,414)
Balance end of year	**$ 12,042**	$ 11,942

Allowance for Funds Used During Construction (AFUDC)

In accordance with regulatory treatment, the Company records AFUDC, which represents the estimated debt and equity costs of capital funds that are necessary to finance the construction of new regulated facilities. While cash is not realized currently from such allowance, it increases the revenue requirement over the service life of the plant through a higher rate base and higher depreciation expense. The equity component of AFUDC is not included in calculating taxable income. The average annual AFUDC rate was 7.65%, 7.48%, and 7.48%, respectively, for the years 2008, 2007, and 2006. AFUDC, net of taxes, as a percentage of net income after dividends on preference stock was 12.62%, 3.59%, and 0.61%, respectively, for 2008, 2007, and 2006.

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Property Damage Reserve

The Company accrues for the cost of repairing damages from major storms and other uninsured property damages, including uninsured damages to transmission and distribution facilities, generation facilities, and other property. The cost of such damages is charged to the reserve. The Florida PSC approved annual accrual to the property damage reserve is $3.5 million, with a target level for the reserve between $25.1 million and $36.0 million. The Florida PSC also authorized the Company to make additional accruals above the $3.5 million at the Company's discretion. The Company accrued total expenses of $3.5 million in 2008, $3.5 million in 2007, and $6.5 million in 2006. As of December 31, 2008, the balance in the Company's property damage reserve totaled approximately $9.8 million, which is included in deferred liabilities in the balance sheets. See Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery" for additional information regarding the surcharge mechanism approved by the Florida PSC to replenish these reserves.

Injuries and Damages Reserve

The Company is subject to claims and suits arising in the ordinary course of business. As permitted by the Florida PSC, the Company accrues for the uninsured costs of injuries and damages by charges to income amounting to $1.6 million annually. The Florida PSC has also given the Company the flexibility to increase its annual accrual above $1.6 million to the extent the balance in the reserve does not exceed $2 million and to defer expense recognition of liabilities greater than the balance in the reserve. The cost of settling claims is charged to the reserve. The injuries and damages reserve was $2.5 million and $2.2 million at December 31, 2008 and 2007, respectively, and is included in Current Liabilities in the balance sheets. Liabilities in excess of the reserve balance of $0.8 million and $0.8 million at December 31, 2008 and 2007, respectively, are included in Deferred Credits and Other Liabilities in the balance sheets. Corresponding regulatory assets of $0.8 million and $0.8 million at December 31, 2008 and 2007, respectively, are included in Current Assets in the balance sheets.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered through fuel cost recovery rates approved by the Florida PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (categorized in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Florida PSC-approved hedging program. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 6 under "Financial Instruments" for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2008.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Other financial instruments for which the carrying amounts did not equal fair values at December 31 were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2008	**$ 849,265**	**$ 831,763**
2007	$ 740,050	$ 725,885

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2). See Note 9 for all other items recognized at fair value in the financial statements.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income and changes in the fair value of qualifying cash flow hedges, and prior to the adoption of SFAS No.158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158) the minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company had established certain wholly-owned trusts to issue preferred securities. The Company is not considered the primary beneficiary of the trusts. Therefore, the investments in these trusts were reflected as Other Investments for the Company, and the related loans from the trusts were included in Long-term Debt in the balance sheets. In November 2007, the Company redeemed $41.2 million of its Series E Junior Subordinated Notes and the related trust preferred and common securities of Gulf Power Capital Trust IV. As of December 31, 2008, the Company no longer had any outstanding trust preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trusts" for additional information.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2009. The Company also provides a defined benefit pension plan for a selected group of management and highly compensated employees. Benefits under this non-qualified plan are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds related trusts to the extent required by the FERC. For the year ending December 31, 2009, postretirement trust contributions are expected to total approximately $34,000.

The measurement date for plan assets and obligations for 2008 was December 31 while the measurement date for prior years was September 30. Pursuant to SFAS No. 158, the Company was required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ending December 31, 2008. As permitted, the Company adopted the measurement date provisions of SFAS No. 158 effective January 1, 2008 resulting in an increase in long-term liabilities of approximately $1.4 million and an increase in prepaid pension costs of approximately $0.6 million.

Pension Plans

The total accumulated benefit obligation for the pension plans was $243 million in 2008 and $230 million in 2007. Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the projected benefit obligations and the fair value of plan assets were as follows:

	2008	2007
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 251,781**	$ 246,569
Service cost	**8,437**	6,835
Interest cost	**19,344**	14,519
Benefits paid	**(15,880)**	(11,625)
Plan amendments	**-**	1,698
Actuarial (gain) loss	**(2,917)**	(6,215)
Balance at end of year	**260,765**	251,781
Change in plan assets		
Fair value of plan assets at beginning of year	**345,398**	305,525
Actual return (loss) on plan assets	**(101,036)**	50,816
Employer contributions	**925**	682
Benefits paid	**(15,880)**	(11,625)
Fair value of plan assets at end of year	**229,407**	345,398
Funded status at end of year	**(31,358)**	93,617
Fourth quarter contributions	**-**	149
(Accrued liability) prepaid pension asset	**$ (31,358)**	$ 93,766

At December 31, 2008, the projected benefit obligations for the qualified and non-qualified pension plans were $247.9 million and $12.9 million, respectively. All pension plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk.

The actual composition of the Company's pension plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	**2008**	2007
Domestic equity	36%	**34%**	38%
International equity	24	**23**	24
Fixed income	15	**14**	15
Real estate	15	**19**	16
Private equity	10	**10**	7
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's pension plans consist of:

	2008	2007
	(in thousands)	
Prepaid pension costs	**$ -**	$107,151
Other regulatory assets	**71,990**	6,561
Current liabilities, other	**(863)**	(639)
Other regulatory liabilities	**-**	(60,464)
Employee benefit obligations	**(30,494)**	(12,403)

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2008 and 2007 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	**Net (Gain) Loss**
	(in thousands)	
Balance at December 31, 2008:		
Regulatory assets	**$ 9,984**	**$ 62,006**
Regulatory liabilities	**-**	**-**
Total	**$ 9,984**	**$ 62,006**
Balance at December 31, 2007:		
Regulatory assets	$ 1,900	$ 4,661
Regulatory liabilities	9,932	(70,396)
Total	$ 11,832	$ (65,735)
Estimated amortization in net periodic pension cost in 2009:		
Regulatory assets	$ 1,478	$ 224
Regulatory liabilities	-	-
Total	$ 1,478	$ 224

The changes in the balances of regulatory assets and regulatory liabilities related to the defined benefit pension plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in thousands)	
Balance at December 31, 2006	$ 5,091	$ (23,478)
Net (gain) loss	313	(35,765)
Change in prior service costs	1,698	-
Reclassification adjustments:		
Amortization of prior service costs	(199)	(1,221)
Amortization of net gain	(342)	-
Total reclassification adjustments	(541)	(1,221)
Total change	1,470	(36,986)
Balance at December 31, 2007	**$ 6,561**	**$ (60,464)**
Net (gain) loss	**66,170**	**61,989**
Change in prior service costs	**-**	**-**
Reclassification adjustments:		
Amortization of prior service costs	**(323)**	**(1,525)**
Amortization of net gain	**(418)**	**-**
Total reclassification adjustments	**(741)**	**(1,525)**
Total change	**65,429**	**60,464**
Balance at December 31, 2008	**$ 71,990**	**$ -**

Components of net periodic pension cost (income) were as follows:

	2008	2007	2006
		(in thousands)	
Service cost	**$ 6,750**	$ 6,835	$ 6,980
Interest cost	**15,475**	14,519	13,358
Expected return on plan assets	**(23,757)**	(21,934)	(20,727)
Recognized net (gain) loss	**334**	342	463
Net amortization	**1,478**	1,419	1,313
Net periodic pension cost (income)	**$ 280**	$ 1,181	$ 1,387

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2008, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2009	$ 13,699
2010	14,119
2011	14,662
2012	15,342
2013	16,033
2014 to 2018	95,308

Other Postretirement Benefits

Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the accumulated postretirement benefit obligations (APBO) and in the fair value of plan assets were as follows:

	2008	2007
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 73,909**	$ 73,985
Service cost	**1,766**	1,351
Interest cost	**5,671**	4,330
Benefits paid	**(4,864)**	(3,586)
Actuarial (gain) loss	**(4,522)**	(2,430)
Retiree drug subsidy	**431**	259
Balance at end of year	**72,391**	73,909
Change in plan assets		
Fair value of plan assets at beginning of year	**19,610**	17,640
Actual return (loss) on plan assets	**(5,556)**	2,934
Employer contributions	**3,559**	2,363
Benefits paid	**(4,433)**	(3,327)
Fair value of plan assets at end of year	**13,180**	19,610
Funded status at end of year	**(59,211)**	(54,299)
Fourth quarter contributions	**-**	872
Accrued liability	**$ (59,211)**	$ (53,427)

Other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of the year, along with the targeted mix of assets, is presented below:

	Target	2008	2007
Domestic equity	35%	**33%**	37%
International equity	23	**22**	23
Fixed income	18	**17**	17
Real estate	14	**19**	16
Private equity	10	**9**	7
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of:

	2008	2007
	(in thousands)	
Other regulatory assets	**$ 9,922**	$ 8,040
Current liabilities, other	**(500)**	(511)
Employee benefit obligations	**(58,711)**	(52,916)

Presented below are the amounts included in regulatory assets at December 31, 2008 and 2007, related to the other postretirement benefit plans that had not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	Net (Gain) Loss	Transition Obligation
		(in thousands)	
Balance at December 31, 2008:			
Regulatory assets	**$ 3,187**	**$ 5,302**	**$ 1,433**
Balance at December 31, 2007:			
Regulatory assets	$ 3,619	$ 2,544	$ 1,877
Estimated amortization as net periodic postretirement benefit cost in 2009:			
Regulatory assets	$ 346	$ (87)	$ 356

The change in the balance of regulatory assets related to the other postretirement benefit plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Regulatory Assets
	(in thousands)
Beginning balance	$ 12,877
Net gain	(4,045)
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	(356)
Amortization of prior service costs	(346)
Amortization of net gain	(90)
Total reclassification adjustments	(792)
Total change	(4,837)
Balance at December 31, 2007	**$ 8,040**
Net gain	**2,759**
Change in prior service costs	**-**
Reclassification adjustments:	
Amortization of transition obligation	**(445)**
Amortization of prior service costs	**(432)**
Amortization of net gain	**-**
Total reclassification adjustments	**(877)**
Total change	**1,882**
Balance at December 31, 2008	**$ 9,922**

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2008	2007	2006
		(in thousands)	
Service cost	**$ 1,413**	$ 1,351	$ 1,424
Interest cost	**4,536**	4,330	3,940
Expected return on plan assets	**(1,452)**	(1,320)	(1,264)
Net amortization	**702**	792	857
Net postretirement cost	**$ 5,199**	$ 5,153	$ 4,957

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2008, 2007, and 2006 by approximately $1.4 million, $1.5 million, and $1.7 million, respectively.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2009	$ 4,475	$ (378)	$ 4,097
2010	4,792	(442)	4,350
2011	5,202	(494)	4,708
2012	5,449	(565)	4,884
2013	5,689	(638)	5,051
2014 to 2018	31,319	(4,401)	26,918

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2005 for the 2006 plan year using a discount rate of 5.50%.

	2008	2007	2006
Discount	**6.75%**	6.30%	6.00%
Annual salary increase	**3.75**	3.75	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.15% for 2009, decreasing gradually to 5.50% through the year 2015 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2008 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in thousands)	
Benefit obligation	**$ 3,904**	**$ 4,211**
Service and interest costs	**275**	**236**

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85% matching contribution up to 6% of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75% up to 6% of the employee's base salary. Total matching contributions made to the plan for 2008, 2007, and 2006 were $3.5 million, $3.5 million, and $3.0 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. The EPA concurrently issued notices of violation relating to the Company's Plant Crist and a unit at Georgia Power's Plant Scherer that is partially owned by the Company. In early 2000, the EPA filed a motion to amend its complaint to add the allegations in the notice of violation and to add the Company as a defendant. However, in March 2001, the court denied the motion based on lack of jurisdiction, and the EPA has not refiled. After Alabama Power was dismissed from the original action for jurisdictional reasons, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The action against Georgia Power has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where it was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The ultimate outcome of these matters cannot be determined at this time.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in this matter could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company received authority from the Florida PSC to recover approved environmental compliance costs through the environmental cost recovery clause. The Florida PSC reviews costs and adjusts rates up or down annually.

The Company's environmental remediation liability includes estimated costs of environmental remediation projects of approximately $66.8 million as of December 31, 2008. These estimated costs relate to site closure criteria by the Florida Department of Environmental Protection (FDEP) for potential impacts to soil and groundwater from herbicide applications at the Company's substations. The schedule for completion of the remediation projects will be subject to FDEP approval. The projects have been approved by the Florida PSC for recovery through the Company's environmental cost recovery clause; therefore, there is no impact to net income as a result of these liabilities.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the Company's financial statements.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $0.8 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company, offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Intercompany Interchange Contract

The Company's generation fleet is operated under the Intercompany Interchange Contract (IIC), as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the traditional operating companies (including the Company), Southern Power, and SCS, as agent, under the terms of which the power pool of Southern Company is operated, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms and Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan did not have a material impact on the Company's financial statements. In November 2007 Southern Company notified the FERC that the plan had been implemented. On December 12, 2008 the FERC division of audits issued for public comment its final audit report pertaining to compliance implementation and related matters. No comments challenging the audits report's findings were submitted. A decision is now pending from the FERC.

Retail Regulatory Matters

Fuel Cost Recovery

The Company petitions for fuel cost recovery rates to be approved by the Florida PSC on an annual basis. The Company continuously monitors the under recovered fuel cost balance in light of the inherent variability in fuel costs. If the projected fuel cost over or under recovery exceeds 10% of the projected fuel revenue applicable for the period, the Company is required to notify the Florida PSC and indicate if an adjustment to the fuel cost recovery is being requested.

On July 29, 2008, the Florida PSC approved a request by the Company to increase the fuel cost recovery factor effective with billings beginning September 2008. The remaining portion of the projected under recovered balance is expected to be recovered in 2009. On September 2, 2008, the Company filed its 2009 projected fuel cost recovery filing with the Florida PSC which includes the fuel factors proposed for January 2009 through December 2009. On October 13, 2008, the Company notified the Florida PSC that the updated projected fuel cost under recovery balance at year-end exceeds the 10% threshold, but no adjustment to the fuel factors were requested.

On November 6, 2008, the Florida PSC approved an increase of approximately 12.9% in the fuel factor for retail customers, effective with billings beginning January 2009. The fuel factors are intended to allow the Company to recover its projected 2009 fuel and purchased power costs as well as the 2008 under recovered amounts in 2009. Fuel cost recovery revenues, as recorded on the financial statements, are adjusted for differences in actual recoverable costs and amounts billed in current regulated rates. Accordingly, changing the billing factor has no significant effect on the Company's revenues or net income, but does impact annual cash flow. As of December 31, 2008, the Company had an under recovered fuel balance of approximately $97 million, which is included in current assets in the balance sheets.

Environmental Cost Recovery

The Florida Legislature adopted legislation for an environmental cost recovery clause, which allows an electric utility to petition the Florida PSC for recovery of prudent environmental compliance costs that are not being recovered through base rates or any other recovery mechanism. Such environmental costs include operation and maintenance expense, emission allowance expense, depreciation, and a return on invested capital. This legislation also allows recovery of costs incurred as a result of an agreement between the Company and the FDEP for the purpose of ensuring compliance with ozone ambient air quality standards adopted by the EPA. In August 2007, the Florida PSC voted to approve a stipulation among the Company, the Office of Public Counsel, and the Florida Industrial Power Users Group regarding the Company's plan for complying with certain federal and state regulations addressing air quality. The Company's environmental compliance plan as filed in March 2007 contemplates implementation of specific projects identified in the plan from 2007 through 2018. The stipulation covers all elements of the current plan that are scheduled to be implemented in the 2007 through 2011 timeframe. On September 18, 2008, the Company filed an update to the plan which was approved by the Florida PSC on November 4, 2008. The Florida PSC acknowledged that the costs associated with the Company's Clean Air Interstate Rule/Clean Air Mercury Rule/Clean Air Visibility Rule compliance plan are eligible for recovery through the environmental cost recovery clause. During 2008, 2007, and 2006, the Company recorded environmental cost recovery clause revenues of $50.0 million, $43.6 million, and $40.9 million, respectively. Annually, the Company seeks recovery of projected costs including any true-up amounts from prior periods. At December 31, 2008, the over recovered balance was approximately $71,000.

Storm Damage Cost Recovery

Under authority granted by the Florida PSC, the Company maintains a reserve for property damage to cover the cost of uninsured damages from major storms to its transmission and distribution facilities, generation facilities, and other property.

In July 2006, the Florida PSC issued an order (2006 Order) approving a stipulation and settlement between the Company and several consumer groups that resolved all matters relating to the Company's request for recovery of incurred costs for storm-recovery activities and the replenishment of the Company's property damage reserve. The 2006 Order provided for an extension of the storm-recovery surcharge then being collected by the Company for an additional 27 months, expiring in June 2009.

Funds collected by the Company related to the storm-recovery costs associated with previous hurricanes had been fully recovered by August 2008. Funds collected by the Company through its storm-recovery surcharge are now being credited to the property damage reserve and will continue through June 2009 when the approved surcharge ends.

According to the 2006 Order, in the case of future storms, if the Company incurs cumulative costs for storm-recovery activities in excess of $10 million during any calendar year, the Company will be permitted to file a streamlined formal request for an interim surcharge. Any interim surcharge would provide for the recovery, subject to refund, of up to 80% of the claimed costs for storm-recovery activities. The Company would then petition the Florida PSC for full recovery through a final or non-interim surcharge or other cost recovery mechanism.

See Note 1 under "Property Damage Reserve" for additional information.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Mississippi Power jointly own Plant Daniel Units 1 and 2, which together represent capacity of 1,000 megawatts. Plant Daniel is a generating plant located in Jackson County, Mississippi. In accordance with the operating agreement, Mississippi Power acts as the Company's agent with respect to the construction, operation, and maintenance of these units.

The Company and Georgia Power jointly own the 818 megawatts capacity Plant Scherer Unit 3. Plant Scherer is a generating plant located near Forsyth, Georgia. In accordance with the operating agreement, Georgia Power acts as the Company's agent with respect to the construction, operation, and maintenance of the unit.

The Company's pro rata share of expenses related to both plants is included in the corresponding operating expense accounts in the statements of income and the Company is responsible for providing its own financing.

At December 31, 2008, the Company's percentage ownership and its investment in these jointly owned facilities were as follows:

	Plant Scherer Unit 3 (coal)	Plant Daniel Units 1 & 2 (coal)
	(in thousands)	
Plant in service	$ 191,688[a]	$ 261,078
Accumulated depreciation	97,937	146,690
Construction work in progress	75,760	253
Ownership	25%	50%

(a) Includes net plant acquisition adjustment of $3.3 million.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined State of Mississippi and State of Georgia income tax returns. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with Internal Revenue Service (IRS) regulations, each company is jointly and severally liable for the tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2008	2007	2006
		(in thousands)	
Federal –			
Current	$ 26,592	$ 51,321	$ 40,472
Deferred	21,481	(9,431)	(470)
	48,073	41,890	40,002
State –			
Current	3,563	6,581	3,651
Deferred	2,467	(1,388)	1,640
	6,030	5,193	5,291
Total	$ 54,103	$ 47,083	$ 45,293

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2008	2007
	(in thousands)	
Deferred tax liabilities–		
Accelerated depreciation	**$ 284,653**	$ 260,720
Fuel recovery clause	**39,176**	22,934
Pension and other employee benefits	**15,356**	38,109
Property reserve	**-**	6,624
Regulatory assets associated with employee benefit obligations	**34,787**	9,206
Regulatory assets associated with asset retirement obligations	**4,877**	4,837
Other	**3,747**	3,316
Total	**382,596**	345,746
Deferred tax assets–		
Federal effect of state deferred taxes	**$ 14,039**	$ 13,168
Post retirement benefits	**17,428**	16,371
Pension and other employee benefits	**38,156**	11,880
Property reserve	**4,872**	-
Other comprehensive loss	**3,097**	2,386
Regulatory liabilities associated with employee benefit obligations	**-**	23,192
Asset retirement obligations	**4,877**	4,837
Other	**7,003**	12,126
Total	**89,472**	83,960
Net deferred tax liabilities	**293,124**	261,786
Less current portion, net	**(38,770)**	(21,685)
Accumulated deferred income taxes in the balance sheets	**$ 254,354**	$ 240,101

At December 31, 2008, the tax-related regulatory assets to be recovered from customers were $24.2 million. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized allowance for funds used during construction. At December 31, 2008, the tax-related regulatory liabilities to be credited to customers were $13.0 million. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.7 million in 2008, $1.7 million in 2007, and $1.8 million in 2006. At December 31, 2008, all investment tax credits available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

A reconciliation of the federal statutory income tax rate to the effective income tax rate is as follows:

	2008	2007	2006
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.5**	2.5	2.8
Non-deductible book depreciation	**0.0**	0.4	0.5
Difference in prior years' deferred and current tax rate	**(0.5)**	(0.6)	(0.8)
Production activities deduction	**0.1**	(1.4)	(0.3)
Allowance for funds used during construction	**(2.2)**	(0.6)	0.0
Other, net	**(0.8)**	(0.4)	(0.8)
Effective income tax rate	**34.1%**	34.9%	36.4%

The decrease in the 2008 effective tax rate is primarily the result of an increase in nontaxable allowance for equity funds used during construction.

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Internal Revenue Code Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The increase from 3% in 2006 to 6% in 2007 was one of several factors that increased the Company's 2007 deduction by $4 million over the 2006 deduction. The resulting additional tax benefit was over $1 million. The IRS has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction for all previous years to conform to the agreement which resulted in a decrease in the 2008 deduction when compared to the 2007 deduction. The net impact of the reversal of unrecognized tax benefits combined with the true-up to the new methodology was immaterial.

Unrecognized Tax Benefits

FIN 48 requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties. For 2008, the total amount of unrecognized tax benefits decreased by $0.6 million, resulting in a balance of $0.3 million as of December 31, 2008.

Changes during the year in unrecognized tax benefits were as follows:

	2008	2007
	(thousands)	
Unrecognized tax benefits at beginning of year	**$ 887**	$ 211
Tax positions from current periods	**93**	469
Tax positions from prior periods	**11**	207
Reductions due to settlements	**(697)**	-
Reductions due to expired statute of limitations	**-**	-
Balance at end of year	**$ 294**	$ 887

The reduction due to settlements relates to the agreement with the IRS regarding the production activities deduction methodology. See "Effective Tax Rate" above for additional information.

Impact on the Company's effective tax rate, if recognized, is as follows:

	2008	2007	Change
		(thousands)	
Tax positions impacting the effective tax rate	**$ 294**	$ 887	$ 593
Tax positions not impacting the effective tax rate	**-**	-	-
Balance of unrecognized tax benefits	**$ 294**	$ 887	$ 593

Accrued interest for unrecognized tax benefits:

	2008	2007
	(thousands)	
Interest accrued at beginning of year	**$ 58**	$ 5
Interest reclassified due to settlements	**(54)**	-
Interest accrued during the year	**13**	53
Balance at end of year	**$ 17**	$ 58

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

The IRS has audited and closed all tax returns prior to 2004. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2002.

It is reasonably possible that the amount of the unrecognized benefit with respect to the majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The possible conclusion or settlement of federal or state audits could impact the balances significantly. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

6. FINANCING

Long-Term Debt Payable to Affiliated Trusts

The Company has formed certain wholly owned trust subsidiaries for the purpose of issuing preferred securities. The proceeds of the related equity investments and preferred security sales were loaned back to the Company through the issuance of junior subordinated notes which constitute substantially all of the assets of these trusts and are reflected in the balance sheets as Long-Term Debt. The Company considers that the mechanisms and obligations relating to the preferred securities issued for its benefit, taken together, constitute a full and unconditional guarantee by it of the trusts' payment obligations with respect to these securities. During 2007, the Company redeemed its last remaining series, which totaled $41.2 million. See Note 1 under "Variable Interest Entities" for additional information on the accounting treatment for these trusts and the related securities.

Bank Term Loans

In 2008, the Company borrowed $110 million under a three-year term loan agreement and $50 million under a short-term loan agreement. The proceeds of these issuances were used for general corporate purposes, including the Company's continuous construction program.

Senior Notes

At December 31, 2008 and 2007, the Company had a total of $588.7 million and $590.0 million of senior notes outstanding, respectively. These senior notes are subordinate to all secured debt of the Company which amounts to approximately $41 million at December 31, 2008.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company has $157.6 million of outstanding pollution control revenue bonds and is required to make payments sufficient for the authorities to meet principal and interest requirements of such bonds.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, Class A preferred stock, preference stock, and common stock authorized. The Company's preferred stock and Class A preferred stock, without preference between classes, rank senior to the Company's preference stock and common stock with respect to payment of dividends and voluntary or involuntary dissolution. No shares of preferred stock or Class A preferred stock were outstanding at December 31, 2008. The Company's preference stock ranks senior to the common stock with respect to the payment of dividends and voluntary or involuntary dissolution. Certain series of the preference stock are subject to redemption at the option of the Company on or after a specified date (typically 5 or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the preference stock. In addition, one series of the preference stock may be redeemed earlier at a redemption price equal to 100% of the liquidation amount plus a make-whole premium based on the present value of the liquidation amount and future dividends.

In January 2007, the Company issued to Southern Company 800,000 shares of the Company's common stock, without par value, and realized proceeds of $80 million. The proceeds were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes. Subsequent to December 31, 2008, the Company issued to Southern Company 1,350,000 shares of the Company's common stock, without par value, and realized proceeds of $135 million.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Assets Subject to Lien

In January 2007, the Company's first mortgage bond indenture was discharged. As a result, there are no longer any first mortgage liens on the Company's property and the Company no longer has to comply with the covenants and restrictions of the first mortgage bond indenture. The Company has granted a lien on its property at Plant Daniel in connection with the issuance of two series of pollution control bonds with an outstanding principal amount of $41 million.

There are no agreements or other arrangements among the affiliated companies under which the assets of one company have been pledged or otherwise made available to satisfy obligations of Southern Company or any of its subsidiaries.

Bank Credit Arrangements

At December 31, 2008, the Company had $120 million of lines of credit with banks, all of which remained unused. These bank credit arrangements will expire in 2009 and $90 million contain provisions allowing one-year term loans executable at expiration. Of the $120 million, $116 million provides liquidity support for the Company's commercial paper program and $4 million provides support for variable rate pollution control bonds. Subsequent to December 31, 2008, the Company obtained an additional $20 million of committed credit. Commitment fees average less than 1/4 of 1% for the Company.

Certain credit arrangements contain covenants that limit the level of indebtedness to capitalization to 65%, as defined in the arrangements. At December 31, 2008, the Company was in compliance with these covenants.

In addition, certain credit arrangements contain cross default provisions to other indebtedness that would trigger an event of default if the Company defaulted on indebtedness over a specified threshold. The cross default provisions are restricted only to indebtedness of the Company. The Company is currently in compliance with all such covenants.

The Company borrows primarily through a commercial paper program that has the liquidity support of committed bank credit arrangements. The Company may also borrow through various other arrangements with banks. At December 31, 2008, the Company had $89.9 million of commercial paper and $50 million of bank notes outstanding. At December 31, 2007, the Company had $40.8 million of commercial paper outstanding. During 2008, the peak amount outstanding for short term debt was $141.2 million and the average amount outstanding was $36.9 million. The average annual interest rate on commercial paper was 2.2%.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company has implemented a fuel-hedging program per the guidelines of the Florida PSC. The Company enters into hedges of forward electricity sales.

At December 31, 2008 and 2007, the Company had a net $31.2 million and $0.2 million fair value liability, respectively, of energy-related derivative contracts designated as regulatory hedges in the financial statements.

The gains and losses arising from these regulatory hedges are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the fuel cost recovery clause. There was no ineffectiveness recorded in the earnings for any period presented. The Company has energy-related hedges in place up to and including 2011.

The Company also enters into derivatives to hedge exposure to changes in interest rates. Derivatives related to forecasted transactions are accounted for as cash flow hedges and will be terminated at the time the underlying debt is issued. The derivatives employed as hedging instruments are structured to minimize ineffectiveness. As such, no ineffectiveness has been recorded in earnings for any period presented. At December 31, 2008, the Company had no interest rate derivatives outstanding.

The fair value gains or losses for cash flow hedges are recorded in other comprehensive income and are reclassified into earnings at the same time the hedged items affect earnings. In 2008, 2007, and 2006, the Company settled gains/(losses) totaling $(5.2) million,

$3.0 million, and $(5.4) million, respectively, upon termination of certain interest derivatives at the same time it issued debt. The effective portion of these gains/(losses) have been deferred in other comprehensive income and will be amortized to interest expense over the life of the original interest derivative. For the years 2008, 2007, and 2006, approximately $0.9 million, $0.7 million, and $0.4 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. For 2009, pre-tax losses of approximately $1.1 million are expected to be reclassified from other comprehensive income to interest expense. The Company has deferred realized net losses that are being amortized through 2018.

All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. See Note 9 for additional information.

7. COMMITMENTS

Construction Program

The Company is engaged in a continuous construction program, the cost of which is currently estimated to total $478 million in 2009, $337 million in 2010, and $400 million in 2011. The construction programs are subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; storm impacts; changes in environmental statutes and regulations; changes in FERC rules and regulations; Florida PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2008, significant purchase commitments were outstanding in connection with the ongoing construction program.

Included in the amounts above are $335 million in 2009, $164 million in 2010, and $233 million in 2011 for environmental expenditures. The Company does not have any new generating capacity under construction. Construction of new transmission and distribution facilities and other capital improvements, including those needed to meet environmental standards for the Company's existing generation, transmission, and distribution facilities, are ongoing.

Long-Term Service Agreements

The Company has a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for a combined cycle generating facility. The LTSA provides that GE will perform all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in the LTSA.

In general, the LTSA is in effect through two major inspection cycles of the unit. Scheduled payments to GE, which are subject to price escalation, are made at various intervals based on actual operating hours of the unit. Total remaining payments to GE under the LTSA for facilities owned are currently estimated at $62.5 million over the remaining life of the LTSA, which is currently estimated to be up to 9 years. However, the LTSA contains various cancellation provisions at the option of the Company.

Payments made under the LTSA prior to the performance of any planned inspections are recorded as prepayments. These amounts are included in Current Assets and Deferred Charges and Other Assets in the balance sheets, for 2008 and 2007, respectively. Inspection costs are capitalized or charged to expense based on the nature of the work performed.

Limestone Commitments

As part of the Company's program to reduce sulfur dioxide emissions from certain of its coal plants, the Company has begun construction of flue gas desulfurization projects and has entered into various long-term commitments for the procurement of limestone to be used in such equipment. Limestone contracts are structured with tonnage minimums and maximums in order to account for fluctuations in coal burn and sulfur content. The Company has a minimum contractual obligation of 0.8 million tons equating to approximately $63.8 million, through 2019. Estimated expenditures (based on minimum contracted obligated dollars) over the next five years are none in 2009, $5.7 million in 2010, $5.8 million in 2011, $6.0 million in 2012, and $6.1 million in 2013. Limestone costs are expected to be recovered through the environmental cost recovery clause.

Fuel and Purchased Power Commitments

To supply a portion of the fuel requirements of the generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2008. Also, the Company has entered into various long-term commitments for the purchase of capacity, electricity, and transmission.

Total estimated minimum long-term obligations at December 31, 2008 were as follows:

	Commitments		
	Purchased Power*	Natural Gas	Coal
		(in thousands)	
2009	$ 23,007	$ 112,618	$ 282,370
2010	26,811	85,713	158,520
2011	26,861	42,607	23,966
2012	26,927	20,149	-
2013	27,070	20,127	-
2014 and thereafter	3,918	151,016	-
Total	$ 134,594	$ 432,230	$ 464,856

*Included above is $81 million in obligations with affiliated companies.

Additional commitments for fuel will be required to supply the Company's future needs.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and all of the other Southern Company traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total operating lease expenses were $5.0 million, $4.7 million, and $4.9 million, for 2008, 2007, and 2006, respectively. Included in these lease expenses are railcar lease costs which are charged to fuel inventory and are allocated to fuel expense as the fuel is used. These expenses are then recovered through the Company's fuel cost recovery clause. The Company's share of the lease costs charged to fuel inventories was $4.0 million in 2008, $4.4 million in 2007, and $4.6 million in 2006. The Company includes any step rents, escalations, and lease concessions in its computation of minimum lease payments, which are recognized on a straight-line basis over the minimum lease term.

At December 31, 2008, estimated minimum rental commitments for noncancelable operating leases were as follows:

	Minimum Lease Payments		
	Rail Cars	Other	Total
		(in thousands)	
2009	$ 3,547	$ 2,002	$ 5,549
2010	3,545	1,877	5,422
2011	1,822	1,820	3,642
2012	1,229	219	1,448
2013	904	-	904
2014 and thereafter	2,223	-	2,223
Total	$ 13,270	$ 5,918	$ 19,188

The Company and Mississippi Power jointly entered into operating lease agreements for aluminum railcars for the transportation of coal to Plant Daniel. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value or to renew the leases at the end of each lease term. The Company and Mississippi Power also have separate lease agreements for other railcars that do not include purchase options.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plant Daniel. The Company's share of these leases was charged to fuel handling expense in the amount of $0.3 million in 2008. The Company's annual lease payments for 2009 to 2010 will average approximately $0.1 million.

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2008, there were 292 current and former employees of the Company participating in the stock option plan, and there were 33.2 million shares of common stock remaining available for awards under this plan. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however, for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards a change in control will provide accelerated vesting.

The estimated fair values of stock options granted in 2008, 2007, and 2006 were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	**2008**	2007	2006
Expected volatility	**13.1%**	14.8%	16.9%
Expected term *(in years)*	**5.0**	5.0	5.0
Interest rate	**2.8%**	4.6%	4.6%
Dividend yield	**4.5%**	4.3%	4.4%
Weighted average grant-date fair value	**$ 2.37**	$ 4.12	$ 4.15

The Company's activity in the stock option plan for 2008 is summarized below:

	Shares Subject to Option	**Weighted Average Exercise Price**
Outstanding at December 31, 2007	**1,225,355**	**$ 31.01**
Granted	**239,507**	**35.79**
Exercised	**(184,865)**	**28.56**
Cancelled	**(232)**	**35.78**
Outstanding at December 31, 2008	**1,279,765**	**32.25**
Exercisable at December 31, 2008	**818,636**	**$ 30.31**

The number of stock options vested, and expected to vest in the future, as of December 31, 2008 was not significantly different from the number of stock options outstanding at December 31, 2008 as stated above. As of December 31, 2008, the weighted average remaining contractual term for the options outstanding and options exercisable was 6.3 years and 5.1 years, respectively, and the aggregate intrinsic value for the options outstanding and options exercisable was $6.1 million and $5.5 million, respectively.

As of December 31, 2008, there was $0.4 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted average period of approximately 8 months.

For the years ended December 31, 2008, 2007, and 2006, total compensation cost for stock option awards recognized in income was $0.8 million, $1.1 million, and $1.0 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.4 million, and $0.4 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007, and 2006 was $1.3 million, $3.0 million, and $1.6 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises for the years ended December 31, 2008, 2007, and 2006 totaled $0.5 million, $1.1 million, and $0.6 million, respectively.

9. FAIR VALUE MEASUREMENTS

On January 1, 2008, the Company adopted FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value, and requires additional disclosures about fair value measurements. The criterion that is set forth in SFAS No. 157 is applicable to fair value measurement where it is permitted or required under other accounting pronouncements.

SFAS No. 157 defines fair value as the exit price, which is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement. As a means to illustrate the inputs used, SFAS No. 157 establishes a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

The adoption of SFAS No. 157 has not resulted in any significant changes to the methodologies used for fair value measurement. Primarily all the changes in the fair value of assets and liabilities are recorded in other comprehensive income or regulatory assets and liabilities, and thus the impact on earnings is limited to derivatives that do not qualify for hedge accounting.

The fair value measurements performed on a recurring basis and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

At December 31, 2008:	Level 1	Level 2	Level 3	Total
		(in millions)		
Assets:				
Energy-related derivatives total fair value	$ -	$ 1.0	$ -	$ 1.0
Liabilities:				
Energy-related derivatives total fair value	$ -	$ 32.2	$ -	$ 32.2

Energy-related derivatives primarily consist of over-the-counter contracts. See Note 6 under "Financial Instruments" for additional information. These financial instruments and investments are valued primarily using the market approach.

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2008 and 2007 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends on Preference Stock
		(in thousands)	
March 2008	**$ 311,535**	**$ 40,708**	**$ 19,530**
June 2008	**349,867**	**52,314**	**26,992**
September 2008	**421,841**	**69,039**	**37,343**
December 2008	**303,960**	**30,628**	**14,480**
March 2007	$ 296,233	$ 40,775	$ 18,863
June 2007	298,394	45,017	21,275
September 2007	376,556	64,999	34,163
December 2007	288,625	25,125	9,817

The Company's business is influenced by seasonal weather conditions.

SELECTED FINANCIAL AND OPERATING DATA 2004-2008

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	2008	2007	2006	2005	2004
Operating Revenues (in thousands)	**$1,387,203**	$1,259,808	$1,203,914	$1,083,622	$960,131
Net Income after Dividends on Preferred and Preference Stock (in thousands)	**$98,345**	$84,118	$75,989	$75,209	$68,223
Cash Dividends on Common Stock (in thousands)	**$81,700**	$74,100	$70,300	$68,400	$70,000
Return on Average Common Equity (percent)	**12.66**	12.32	12.29	12.59	11.83
Total Assets (in thousands)	**$2,879,025**	$2,498,987	$2,340,489	$2,175,797	$2,111,877
Gross Property Additions (in thousands)	**$390,744**	$239,337	$147,086	$142,583	$161,205
Capitalization (in thousands):					
Common stock equity	**$ 822,092**	$731,255	$634,023	$602,344	$592,172
Preferred and preference stock	**97,998**	97,998	53,887	53,891	4,098
Long-term debt	**849,265**	740,050	696,098	616,554	623,155
Total (excluding amounts due within one year)	**$1,769,355**	$1,569,303	$1,384,008	$1,272,789	$1,219,425
Capitalization Ratios (percent):					
Common stock equity	**46.5**	46.6	45.8	47.3	48.6
Preferred and preference stock	**5.5**	6.2	3.9	4.2	0.3
Long-term debt	**48.0**	47.2	50.3	48.5	51.1
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	**-**	-	-	A1	A1
Standard and Poor's	**-**	-	-	A+	A+
Fitch	**-**	-	-	A+	A+
Preferred Stock/ Preference Stock -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A-**	A-	A-	A-	A-
Unsecured Long-Term Debt -					
Moody's	**A2**	A2	A2	A2	A2
Standard and Poor's	**A**	A	A	A	A
Fitch	**A**	A	A	A	A
Customers (year-end):					
Residential	**373,595**	373,036	364,647	354,466	343,151
Commercial	**53,548**	53,838	53,466	53,398	51,865
Industrial	**287**	298	295	298	285
Other	**499**	491	484	479	473
Total	**427,929**	427,663	418,892	408,641	395,774
Employees (year-end)	**1,342**	1,324	1,321	1,335	1,336

SELECTED FINANCIAL AND OPERATING DATA 2004-2008 (continued)

Gulf Power Company 2008 Annual Report

	2008	2007	2006	2005	2004
Operating Revenues (in thousands):					
Residential	**$ 581,723**	$537,668	$510,995	$465,346	$401,382
Commercial	**369,625**	329,651	305,049	273,114	232,928
Industrial	**165,564**	135,179	132,339	123,044	99,420
Other	**3,854**	3,831	3,655	3,355	3,140
Total retail	**1,120,766**	1,006,329	952,038	864,859	736,870
Wholesale - non-affiliates	**97,065**	83,514	87,142	84,346	73,537
Wholesale - affiliates	**106,989**	113,178	118,097	91,352	110,264
Total revenues from sales of electricity	**1,324,820**	1,203,021	1,157,277	1,040,557	920,671
Other revenues	**62,383**	56,787	46,637	43,065	39,460
Total	**$1,387,203**	$1,259,808	$1,203,914	$1,083,622	$960,131
Kilowatt-Hour Sales (in thousands):					
Residential	**5,348,642**	5,477,111	5,425,491	5,319,630	5,215,332
Commercial	**3,960,923**	3,970,892	3,843,064	3,735,776	3,695,471
Industrial	**2,210,597**	2,048,389	2,136,439	2,160,760	2,113,027
Other	**23,237**	24,496	23,886	22,730	22,579
Total retail	**11,543,399**	11,520,888	11,428,880	11,238,896	11,046,409
Sales for resale - non-affiliates	**1,816,839**	2,227,026	2,079,165	2,295,850	2,256,942
Sales for resale - affiliates	**1,871,158**	2,884,440	2,937,735	1,976,368	3,124,788
Total	**15,231,396**	16,632,354	16,445,780	15,511,114	16,428,139
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**10.88**	9.82	9.42	8.75	7.70
Commercial	**9.33**	8.30	7.94	7.31	6.30
Industrial	**7.49**	6.60	6.19	5.69	4.71
Total retail	**9.71**	8.73	8.33	7.70	6.67
Wholesale	**5.53**	3.85	4.09	4.11	3.42
Total sales	**8.70**	7.23	7.04	6.71	5.60
Residential Average Annual Kilowatt-Hour Use Per Customer	**14,274**	14,755	15,032	15,181	15,096
Residential Average Annual Revenue Per Customer	**$1,552**	$1,448	$1,416	$1,328	$1,162
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**2,659**	2,659	2,659	2,712	2,712
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,360**	2,215	2,195	2,124	2,061
Summer	**2,533**	2,626	2,479	2,433	2,421
Annual Load Factor (percent)	**56.7**	55.0	57.9	57.7	57.1
Plant Availability Fossil-Steam (percent)	**88.6**	93.4	91.3	89.7	92.4
Source of Energy Supply (percent):					
Coal	**77.3**	81.8	82.5	79.7	77.9
Gas	**15.3**	13.6	12.4	13.1	14.4
Purchased power -					
From non-affiliates	**2.6**	1.6	1.9	2.8	4.5
From affiliates	**4.8**	3.0	3.2	4.4	3.2
Total	**100.0**	100.0	100.0	100.0	100.0

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MISSISSIPPI POWER COMPANY

FINANCIAL SECTION

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Mississippi Power Company 2008 Annual Report

The management of Mississippi Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This Annual Report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.

Anthony J. Topazi
President and Chief Executive Officer

Frances Turnage
Vice President, Treasurer, and Chief Financial Officer

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Mississippi Power Company

We have audited the accompanying balance sheets and statements of capitalization of Mississippi Power Company (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2008 and 2007, and the related statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements (pages II-328 to II-362) present fairly, in all material respects, the financial position of Mississippi Power Company at December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

OVERVIEW

Business Activities

Mississippi Power Company (the Company) operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located within the State of Mississippi and to wholesale customers in the Southeast.

Many factors affect the opportunities, challenges, and risks of the Company's business of selling electricity. These factors include the ability to maintain a constructive regulatory environment, to maintain energy sales in the midst of the current economic downturn, and to effectively manage and secure timely recovery of rising costs. The Company has various regulatory mechanisms that operate to address cost recovery. Since 2005, the Company has completed a number of regulatory proceedings that provide for the timely recovery of costs.

Appropriately balancing required costs and capital expenditures with reasonable retail rates will continue to challenge the Company for the foreseeable future. Hurricane Katrina, the worst natural disaster in the Company's history, hit the Gulf Coast of Mississippi in August 2005, causing substantial damage to the Company's service territory. All of the Company's 195,000 customers were without service immediately after the storm. Through a coordinated effort with Southern Company, as well as non-affiliated companies, the Company restored power to all who could receive it within 12 days. However, due to obstacles in the rebuilding process, the Company has over 7,500 fewer retail customers as of December 31, 2008 as compared to pre-storm levels. In 2006, the Company received from the Mississippi Development Authority (MDA) a Community Development Block Grant (CDBG) in the amount of $276.4 million for costs related to Hurricane Katrina, of which $267.6 million was for the retail portion of the Hurricane Katrina restoration costs. In 2007, the Company received $109.3 million of storm restoration bond proceeds under the state bond program of which $25.2 million was for retail storm restoration cost, $60.0 million was to increase the Company's retail property damage reserve, and $24.1 million was to cover the retail portion of construction of a new storm operations center. In 2008, the Company received an additional $7.3 million of storm restoration bond proceeds related to the retail portion of construction for the storm operations center and anticipates the receipt of approximately $3.2 million in 2009 as final recovery of these retail costs.

The Company's retail base rates are set under the Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi Public Service Commission (PSC). PEP was designed with the objective to reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high.

Key Performance Indicators

In striving to maximize shareholder value while providing cost effective energy to customers, the Company continues to focus on several key indicators. These indicators are used to measure the Company's performance for customers and employees.

In recognition that the Company's long-term financial success is dependent upon how well it satisfies its customers' needs, the Company's retail base rate mechanism, PEP, includes performance indicators that directly tie customer service indicators to the Company's allowed return. PEP measures the Company's performance on a 10-point scale as a weighted average of results in three areas: average customer price, as compared to prices of other regional utilities (weighted at 40%); service reliability, measured in outage minutes per customer (40%); and customer satisfaction, measured in a survey of residential customers (20%). See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

In addition to the PEP performance indicators, the Company focuses on other performance measures, including broader measures of customer satisfaction, plant availability, system reliability, and net income. The Company's financial success is directly tied to the satisfaction of its customers. Management uses customer satisfaction surveys to evaluate the Company's results. Peak season equivalent forced outage rate (Peak Season EFOR) is an indicator of plant availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours. The actual EFOR performance for 2008 did not meet the target due to the effects of an unanticipated turbine rotor outage at Plant Daniel Unit 1. Net income after dividends on preferred stock is the primary component of the Company's contribution to Southern Company's earnings per share goal. Recognizing the critical role in the Company's success played by the Company's employees, employee-related measures are a significant management focus. These measures include safety and inclusion. The 2008 safety performance of the Company was the second best in the history of the Company with an Occupational Safety and Health Administration Incidence Rate of 0.53. This achievement resulted in the Company being recognized as one of the top in safety performance among all utilities in the Southeastern Electric Exchange. Inclusion initiatives resulted in performance at target levels for the year. The Company's 2008 results compared with its targets for some of these key indicators are reflected in the following chart.

Key Performance Indicator	2008 Target Performance	2008 Actual Performance
Customer Satisfaction	Top quartile in customer surveys	Top quartile
Peak Season EFOR	3.0% or less	6.53%
Net Income	$84.3 million	$86.0 million

See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance. The financial performance achieved in 2008 reflects the continued emphasis that management places on all of these indicators, as well as the commitment shown by employees in achieving or exceeding management's expectations.

Earnings

The Company's net income after dividends on preferred stock was $86.0 million in 2008 compared to $84.0 million in 2007. The 2.4% increase in 2008 was primarily the result of an increase in territorial base revenues due to a retail base rate increase effective January 2008 and an increase in wholesale capacity revenues, partially offset by an increase in depreciation and amortization primarily due to the amortization of regulatory items, an increase in non-fuel related expenses, and an increase in charitable contributions. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Net income after dividends on preferred stock was $84.0 million in 2007 compared to $82.0 million in 2006. The 2.4% increase in 2007 was primarily the result of an increase in territorial base revenues due to a retail base rate increase effective April 1, 2006, territorial sales growth, and an increase in total other income and expense as a result of charitable contributions in 2006. These factors were partially offset by an increase in non-fuel related expenses and an increase in depreciation and amortization expenses. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information.

Net income after dividends on preferred stock of $82.0 million in 2006 increased when compared to $73.8 million in 2005 primarily as a result of an increase in retail base rates which became effective April 1, 2006, an increase in wholesale base revenues partially offset by an increase in depreciation and amortization expenses, a decrease in total other income and expense as a result of charitable contributions, and higher interest rates on long-term debt.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year		
	2008	**2008**	2007	2006
		(in millions)		
Operating revenues	**$1,256.5**	**$142.8**	$104.5	$ 39.5
Fuel	**586.5**	**92.2**	55.6	80.1
Purchased power	**126.6**	**30.7**	22.6	(70.2)
Other operations and maintenance	**260.0**	**4.8**	18.6	(3.0)
Depreciation and amortization	**71.0**	**10.7**	13.5	13.3
Taxes other than income taxes	**65.1**	**4.8**	(0.6)	0.8
Total operating expenses	**1,109.2**	**143.2**	109.7	21.0
Operating income	**147.3**	**(0.4)**	(5.2)	18.5
Total other income and (expense)	**(11.3)**	**(1.1)**	10.9	(8.6)
Income taxes	**48.3**	**(3.4)**	3.7	1.7
Net income	**87.7**	**1.9**	2.0	8.2
Dividends on preferred stock	**1.7**	**-**	-	-
Net income after dividends on preferred stock	**$ 86.0**	**$ 1.9**	$ 2.0	$ 8.2

Operating Revenues

Details of the Company's operating revenues in 2008 and the prior two years were as follows:

	Amount		
	2008	2007	2006
		(in millions)	
Retail – prior year	**$ 727.2**	$ 647.2	$ 618.9
Estimated change in –			
Rates and pricing	**18.8**	8.7	23.2
Sales growth	**(1.1)**	12.3	(5.2)
Weather	**(1.8)**	(2.5)	5.0
Fuel and other cost recovery	**42.3**	61.5	5.3
Retail – current year	**785.4**	727.2	647.2
Wholesale revenues –			
Non-affiliates	**353.8**	323.1	268.8
Affiliates	**100.9**	46.2	76.4
Total wholesale revenues	**454.7**	369.3	345.2
Other operating revenues	**16.4**	17.2	16.8
Total operating revenues	**$1,256.5**	$1,113.7	$1,009.2
Percent change	**12.8%**	10.4%	4.1%

Total retail revenues for 2008 increased 8.0% when compared to 2007 primarily as a result of a retail base rate increase effective January 2008 and higher fuel revenues. Total retail revenues for 2007 increased 12.4% when compared to 2006 primarily as a result of an increase in territorial sales growth, a retail base rate increase effective April 1, 2006, and the Environmental Compliance Overview (ECO) Plan rate effective May 2007. Higher fuel revenues also contributed to the increase. Total retail revenues for 2006 increased 4.6% when compared to 2005 primarily as a result of a retail base rate increase effective April 1, 2006. Higher fuel revenues also contributed to the increase.

Electric rates for the Company include provisions to adjust billings for fluctuations in fuel costs, including the energy component of purchased power costs. Under these provisions, fuel revenues generally equal fuel expenses, including the fuel component of purchased power, and do not affect net income. The fuel and other cost recovery revenues increased in 2008 when compared to 2007 primarily as a result of the increase in fuel and purchased power expenses. The fuel and other cost recovery revenues increased in 2007 when compared to 2006 as a result of higher fuel costs. In 2006, fuel and other cost recovery revenues increased as compared to 2005 as a result of higher fuel costs and an increase in kilowatt-hours (KWH) generated.

Wholesale revenues from sales to non-affiliates will vary depending on the market cost of available energy compared to the cost of the Company and Southern Company system-owned generation, demand for energy within the Southern Company service territory, and availability of Southern Company system generation. Wholesale revenues from sales to non-affiliates increased $30.7 million, or 9.5%, in 2008 as compared to 2007 as a result of a $30.4 million increase in energy revenues, of which $40.4 million was associated with higher fuel prices and a $0.3 million increase in capacity revenues, partially offset by a $10.0 million decrease in KWH sales. Wholesale revenues from sales to non-affiliates increased $54.3 million, or 20.2%, in 2007 as compared to 2006 as a result of a $51.5 million increase in energy revenues, of which $32.0 million was associated with increased KWH sales and $19.5 million was associated with higher fuel prices, and a $2.8 million increase in capacity revenues. In 2006, wholesale revenues from sales to non-affiliates decreased $14.6 million, or 5.1%, compared to 2005. This decrease resulted from a $14.7 million decrease in energy revenues, of which $10.1 million was associated with decreased KWH sales and $4.6 million was associated with lower fuel prices.

Included in wholesale revenues from sales to non-affiliates are revenues from rural electric cooperative associations and municipalities located in southeastern Mississippi. The related revenues increased 8.3%, 12.6%, and 7.1%, in 2008, 2007, and 2006, respectively. The 2008 increase was driven by higher fuel costs. The customer demand experienced by these utilities is determined by factors very similar to those experienced by the Company.

Short-term opportunity energy sales are also included in sales for resale to non-affiliates. These opportunity sales are made at market-based rates (MBRs) that generally provide a margin above the Company's variable cost to produce the energy.

Wholesale revenues from sales to affiliated companies within the Southern Company system will vary from year to year depending on demand, availability and cost of generating resources at each company. These affiliated sales and purchases are made in accordance with the Intercompany Interchange Contract (IIC), as approved by the Federal Energy Regulatory Commission (FERC). Wholesale revenues from sales to affiliated companies increased 118.6% in 2008, when compared to 2007, decreased 39.5% in 2007, when compared to 2006, and increased 51.6% in 2006, when compared to 2005. These energy sales do not have a significant impact on earnings since the energy is generally sold at marginal cost.

Energy Sales

Changes in revenues are influenced heavily by the change in the volume of energy sold from year to year. KWH sales for 2008 and percent change by year were as follows:

	KWHs	**Percent Change**		
	2008	**2008**	2007	2006
	(in millions)			
Residential	**2,121**	**(0.6)%**	0.8%	(2.8)%
Commercial	**2,857**	**(0.7)**	7.5	(1.8)
Industrial	**4,187**	**(3.0)**	4.2	9.1
Other	**39**	**0.3**	4.9	(2.5)
Total retail	**9,204**	**(1.7)**	4.4	2.7
Wholesale				
Non-affiliated	**5,017**	**(3.3)**	12.1	(3.9)
Affiliated	**1,487**	**44.9**	(38.9)	87.4
Total wholesale	**6,504**	**4.7**	(1.5)	10.4
Total energy sales	**15,708**	**0.8**	2.0	5.7

Changes in retail energy sales are comprised of changes in electricity usage by customers, changes in weather, and changes in the number of customers. Residential energy sales decreased 0.6% in 2008 compared to 2007, due to decreased customer usage mainly due to a slowing economy and milder summer weather. Residential energy sales increased 0.8% in 2007 compared to 2006, primarily due to more favorable weather conditions, which offset slow customer growth. Residential energy sales decreased 2.8% in 2006 compared to 2005, due to mild winter weather and fewer customers following Hurricane Katrina.

Commercial energy sales decreased 0.7% in 2008 compared to 2007, due to mild weather and slower than expected customer growth due to the economy. Commercial energy sales increased 7.5% in 2007 compared to 2006, due to customer growth mainly in the casino and hotel industries. Commercial energy sales decreased 1.8% in 2006 compared to 2005, primarily due to commercial customer losses following Hurricane Katrina.

Industrial energy sales decreased 3.0% in 2008 compared to 2007, due to lower customer use from a slowing economy. Industrial energy sales increased 4.2% in 2007 compared to 2006, due to continued recovery after Hurricane Katrina. Industrial energy sales increased 9.1% in 2006 compared to 2005, primarily due to the recovery of load lost in 2005 resulting from Hurricane Katrina.

Wholesale energy sales to non-affiliates decreased 3.3%, increased 12.1%, and decreased 3.9%, in 2008, 2007, and 2006, respectively. Included in wholesale sales from sales to non-affiliates are sales from rural electric cooperative associations and municipalities located in southeastern Mississippi. Compared to the prior year, KWH sales to these utilities decreased 0.9% in 2008 due to slowing growth and milder weather, increased 4.3% in 2007 due to growth in the service territory, and increased 8.9% in 2006 compared to 2005 due to growth in the service territory and recovery from Hurricane Katrina in 2006. KWH sales to non-territorial customers located outside Mississippi Power's service territory decreased 9.6% in 2008 as compared to 2007 primarily due to lower off-system sales. KWH sales to non-territorial customers increased 41.0% in 2007 as compared to 2006 primarily due to more off-system sales. KWH sales to non-territorial customers decreased 33.0% percent in 2006 as compared to 2005 primarily due to less off-system sales. Wholesale sales to non-affiliates will vary depending on the market cost of available energy compared to the cost of the Company and

Southern Company system-owned generation, demand for energy within the Southern Company service territory, and availability of Southern Company system generation.

Wholesale energy sales to affiliates increased 44.9% in 2008 as compared to 2007 primarily due to the availability of the Company's lower cost generation resources sold to affiliated companies. Wholesale energy sales to affiliates decreased 38.9% in 2007 when compared to 2006 primarily due to a decrease in the Company's generation and an increase in territorial sales, therefore, less available to sell to affiliate companies. Wholesale energy sales to affiliates increased 87.4% in 2006 when compared to 2005 primarily due to the availability of the Company's lower cost generation resources sold to affiliated companies.

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. The mix of fuel sources for generation of electricity is determined primarily by demand, the unit cost of fuel consumed, and the availability of generating units. Additionally, the Company purchases a portion of its electricity needs from the wholesale market. Details of the Company's electricity generated and purchased were as follows:

	2008	2007	2006
Total generation *(millions of KWHs)*	**14,324**	14,119	14,224
Total purchased power *(millions of KWHs)*	**2,091**	2,084	1,718
Sources of generation *(percent)* –			
Coal	**67**	69	71
Gas	**33**	31	29
Cost of fuel, generated *(cents per net KWH)* –			
Coal	**3.52**	2.92	2.52
Gas	**6.83**	6.25	6.04
Average cost of fuel, generated *(cents per net KWH)*	**4.43**	3.78	3.34
Average cost of purchased power *(cents per net KWH)*	**6.05**	4.60	4.26

Fuel and purchased power expenses were $713.1 million in 2008, an increase of $122.9 million, or 20.8%, above the prior year costs. This increase was primarily due to a $116.5 million increase in the cost of fuel and purchased power and a $6.4 million increase related to total KWHs generated and purchased. Fuel and purchased power expenses were $590.1 million in 2007, an increase of $78.3 million, or 15.3%, above the prior year costs. This increase was primarily due to a $63.8 million increase in the cost of fuel and purchased power and a $14.5 million increase related to total KWHs generated and purchased. In 2006, fuel and purchased power expenses were $511.9 million, an increase of $9.8 million, or 2.0%, above the prior year costs. This increase was primarily due to an increase of $9.7 million in the cost of fuel and purchased power.

Fuel expense increased $92.2 million in 2008 as compared to 2007. Approximately $86.1 million in additional fuel expenses resulted from higher coal, gas, and transportation prices and a $6.1 million increase in generation from Mississippi Power-owned facilities. Fuel expense increased $55.6 million in 2007 as compared to 2006. Approximately $56.8 million in additional fuel expenses resulted from higher coal, gas, transportation prices, and emission allowances, which were partially offset by a $1.2 million decrease in generation from Mississippi Power-owned facilities. Fuel expense increased $80.1 million in 2006 as compared to 2005 as a result of increases in fuel costs and an increase in generation. This increase in fuel expense is due to a $30.0 million increase in the cost of fuel due to higher coal, gas, transportation, and emission allowance prices and a $50.0 million increase related to more KWHs generated.

Purchased power expense increased $30.7 million, or 32.0%, in 2008 when compared to 2007. The increase was primarily due to an increase in the cost of purchased power. Purchased power expense increased $22.6 million, or 30.9%, in 2007 when compared to 2006. The increase was primarily due to an increase in the cost of purchased power and an increase in the amount of energy purchased which was partially due to a decrease in generation resulting from plant outages. Purchased power expense decreased $70.2 million, or 49%, in 2006 when compared to 2005. The decrease was primarily due to more generation being available to meet customer demand and a decrease in the cost of purchased power. Energy purchases vary from year to year depending on demand and the availability and cost of the Company's generating resources. These expenses do not have a significant impact on earnings since the energy purchases are generally offset by energy revenues through the Company's fuel cost recovery clause.

Over the last several years, coal prices have been influenced by a worldwide increase in demand from developing countries, as well as increases in mining and fuel transportation costs. In the first half of 2008, coal prices reached unprecedented high levels primarily due to increased demand following more moderate pricing in 2006 and 2007. Despite these fluctuations, fuel inventories have been adequate and fuel supply markets have been sufficient to meet expected fuel requirements. Demand for natural gas in the United States also increased in 2007 and the first half of 2008. However, natural gas supplies increased in the last half of 2008 as a result of increased production and higher storage levels due in part to weak industrial demand. Both coal and natural gas prices moderated in the second half of 2008 as the result of a recessionary economy.

Fuel expenses generally do not affect net income, since they are offset by fuel revenues under the Company's fuel cost recovery clause. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Fuel Cost Recovery" and Note 1 to the financial statements under "Fuel Costs" for additional information.

Other Operations and Maintenance Expenses

Total other operations and maintenance expenses increased $4.8 million in 2008 as compared to 2007 primarily due to a $6.9 million increase in transmission and distribution expenses, an increase in administrative expenses primarily resulting from the reclassification of System Restoration Rider (SRR) revenues of $3.8 million to expense pursuant to an order from the Mississippi PSC dated January 9, 2009, a $1.9 million increase in generation related environmental expenses, and a $1.1 million increase in generation operations and outage related expenses. These increases were partially offset by a $9.3 million reclassification of generation construction screening expenses to a regulatory asset upon the FERC acceptance of the wholesale filing on October 24, 2008.

Total other operations and maintenance expenses increased $18.6 million from 2006 to 2007. Other operations expense increased $15.1 million, or 8.8%, in 2007 compared to 2006 primarily as a result of a $4.1 million increase in generation construction screening, a $3.3 million insurance recovery for storm restoration expense recognized in 2006, a $2.1 million increase in employee benefits primarily due to increase in medical expense, a $2.0 million increase in outside and other contract services, and a $2.0 million increase in scheduled production projects. Maintenance expense increased $3.5 million, or 5.2%, in 2007 when compared to 2006, primarily as a result of a $5.5 million increase in generation maintenance expense primarily due to outage work in 2007, partially offset by a $2.0 million decrease in transmission and distribution maintenance expenses due primarily to the deferral of these expenses pursuant to the regulatory accounting order from the Mississippi PSC.

In 2006, total other operations and maintenance expenses decreased $3.0 million compared to 2005. Other operations expense increased $1.9 million, or 1.1%, in 2006 compared to 2005 primarily as a result of a $1.8 million increase in distribution operations expense and a $1.5 million increase in employee benefit expenses, partially offset by a $1.0 million decrease in bad debt expense. Maintenance expense decreased $4.9 million, or 6.8%, in 2006, primarily due to the $3.4 million accrual of certain expenses arising from Hurricane Katrina related to the wholesale portion of the business in 2005 and the $2.8 million partial recovery of these expenses from the CDBG in 2006, partially offset by a $0.5 million increase in 2006 due to the increased operation of combined cycle units as gas costs decreased in 2006 when compared to 2005.

See FUTURE EARNINGS POTENTIAL – "PSC Matters – System Restoration Rider and – Storm Damage Cost Recovery" and "FERC Matters – Wholesale Rate Filing" herein for additional information.

Depreciation and Amortization

Depreciation and amortization expenses increased $10.7 million in 2008 compared to 2007 primarily due to a $5.7 million increase in amortization related to a regulatory liability recorded in 2003 that ended in December 2007 in connection with the Mississippi PSC's accounting order on Plant Daniel capacity, a $2.9 million increase in depreciation expense primarily due to an increase in plant in service, and a $2.4 million increase for amortization of certain reliability-related maintenance costs deferred in 2007 in accordance with a Mississippi PSC order. Depreciation and amortization expenses increased $13.5 million in 2007 compared to 2006 due to a regulatory liability recorded in 2003 in connection with the Mississippi PSC's accounting order on Plant Daniel capacity and an increase in amortization of environmental costs related to the approved ECO Plan. Depreciation and amortization expenses increased $13.3 million in 2006 compared to 2005 due to amortization related to a regulatory liability recorded in 2003 in connection with the Mississippi PSC's accounting order on Plant Daniel capacity and the impact of a new depreciation study effective January 1, 2006. See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" and "Environmental Compliance Overview Plan" for additional information.

Taxes Other Than Income Taxes

Taxes other than income taxes increased 7.9% in 2008 compared to 2007 primarily as a result of a $2.7 million increase in ad valorem taxes and a $1.3 million increase in municipal franchise taxes. Taxes other than income taxes decreased 0.9% in 2007 compared to 2006 primarily as a result of a $2.0 million decrease in ad valorem taxes, partially offset by a $1.5 million increase in municipal franchise taxes. In 2006, taxes other than income taxes increased 1.4% over the prior year primarily as a result of a $0.5 million increase in ad valorem taxes and a $0.3 million increase in municipal franchise taxes. The retail portion of the increase in ad valorem taxes is recoverable under the Company's ad valorem tax cost recovery clause and, therefore, does not affect net income. The increase in municipal franchise taxes is directly related to the increase in total retail revenues.

Total Other Income and (Expense)

The $1.1 million decrease in total other income and (expense) in 2008 compared to 2007 is primarily due to higher charitable contributions of $3.1 million partially offset by $0.4 million increase in revenues from contracting work performed for customers, a $0.6 million decrease in other deductions, and a $0.6 million increase in allowance for equity funds used during construction. The $10.9 million increase in total other income and (expense) in 2007 compared to 2006 is primarily due to higher charitable contributions in 2006 as compared to 2007 and a gain on a contract termination approved by the FERC in 2007. The $8.6 million decrease in total other income and (expense) in 2006 compared to 2005 is primarily due to charitable contributions and higher interest rates on long-term debt.

Income Taxes

Income taxes decreased $3.4 million, or 6.7%, in 2008 primarily due to decreased pre-tax income, the amortization of a regulatory liability pursuant to a December 2007 regulatory accounting order from the Mississippi PSC, and a State of Mississippi manufacturing investment tax credit, partially offset by a decrease in the federal production activities deduction. See Note 3 to the financial statements under "Retail Regulatory Matters" for additional information. Income taxes increased $3.7 million, or 7.8%, in 2007 primarily due to increased pre-tax income and lower federal and state tax credits. Income taxes increased $1.7 million, or 3.7%, in 2006 primarily due to increased pre-tax income, partially offset by higher federal and state tax credits. See Note 5 to the financial statements under "Effective Tax Rate."

Effects of Inflation

The Company is subject to rate regulation that is based on the recovery of costs. PEP is based on annual projected costs, including estimates for inflation. When historical costs are included, or when inflation exceeds projected costs used in rate regulation or market-based prices, the effects of inflation can create an economic loss since the recovery of costs could be in dollars that have less purchasing power. In addition, the income tax laws are based on historical costs. The inflation rate has been relatively low in recent years and any adverse effect of inflation on the Company has not been significant.

FUTURE EARNINGS POTENTIAL

General

The Company operates as a vertically integrated utility providing electricity to retail customers within its traditional service area located in southeast Mississippi and to wholesale customers in the southeastern United States. Prices for electricity provided by the Company to retail customers are set by the Mississippi PSC under cost-based regulatory principles. Retail rates and earnings are reviewed and may be adjusted periodically within certain limitations. Prices for wholesale electricity sales, interconnecting transmission lines and the exchange of electric power are regulated by the FERC. See ACCOUNTING POLICIES – "Application of Critical Accounting Policies and Estimates – Electric Utility Regulation" herein and Note 3 to the financial statements under "FERC Matters" and "Retail Regulatory Matters" for additional information about regulatory matters.

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's primary business of selling electricity. These factors include the Company's ability to maintain a constructive regulatory environment that continues to allow for the recovery of all prudently incurred costs during a time of increasing costs. Future earnings in the near term will depend, in part, upon maintaining energy sales during the current economic downturn, which is subject to a number of factors. These factors include weather, competition, new energy contracts with neighboring utilities, energy conservation practiced by

customers, the price of electricity, the price elasticity of demand, and the rate of economic growth or decline in the Company's service area. Recent recessionary conditions have negatively impacted sales growth. The timing and extent of the economic recovery will impact future earnings.

Environmental Matters

Compliance costs related to the Clean Air Act and other environmental statutes and regulations could affect earnings if such costs cannot continue to be fully recovered in rates on a timely basis. Environmental compliance spending over the next several years may exceed amounts estimated. Some of the factors driving the potential for such an increase are higher commodity costs, market demand for labor, and scope additions and clarifications. The timing, specific requirements, and estimated costs could also change as environmental statutes and regulations are adopted or modified. See Note 3 to the financial statements under "Environmental Matters" for additional information.

New Source Review Actions

In November 1999, the Environmental Protection Agency (EPA) brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. After Alabama Power was dismissed from the original action for jurisdictional reasons, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power, including one co-owned by the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available control technology at the affected units. The action against Georgia Power has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case, and the ultimate outcome of these matters cannot be determined at this time.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in either of these cases could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of

carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Statutes and Regulations

General

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with these environmental requirements involves significant capital and operating costs, a major portion of which is expected to be recovered through existing ratemaking provisions. Through 2008, the Company had invested approximately $202 million in capital projects to comply with these requirements, with annual totals of $41 million, $17 million, and $4.8 million for 2008, 2007, and 2006, respectively. The Company expects that capital expenditures to assure compliance with existing and new statutes and regulations will be an additional $28 million, $61 million, and $111 million for 2009, 2010, and 2011, respectively. The Company's compliance strategy can be affected by changes to existing environmental laws, statutes, and regulations, the cost, availability, and existing inventory of emission allowances, and the Company's fuel mix. Environmental costs that are known and estimable at this time are included in capital expenditures discussed under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

Compliance with any new federal or state legislation or regulations related to global climate change, air quality, combustion byproducts, including coal ash, or other environmental and health concerns could also significantly affect the Company. Although new or revised environmental legislation or regulations could affect many areas of the Company's operations, the full impact of any such changes cannot be determined at this time.

Air Quality

Compliance with the Clean Air Act and resulting regulations has been and will continue to be a significant focus for the Company. Through 2008, the Company had spent approximately $102 million in reducing sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions and in monitoring emissions pursuant to the Clean Air Act. Additional controls are currently being installed at several plants to further reduce air emissions, maintain compliance with existing regulations, and meet new requirements.

In 2004, the EPA designated nonattainment areas under an eight-hour ozone standard. No area within the Company's service area was designated as nonattainment under the eight-hour ozone standard. On March 12, 2008, the EPA issued a final rule establishing a more stringent eight-hour ozone standard which will likely result in designation of new nonattainment areas within the Company's service territory. The EPA is expected to publish those designations in 2010, and require state implementation plans for any nonattainment areas by 2013.

The EPA issued the final Clean Air Interstate Rule (CAIR) in March 2005. This cap-and-trade rule addresses power plant SO_2 and NO_x emissions that were found to contribute to nonattainment of the eight-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including the State of Mississippi, are subject to the requirements of the rule. The rule calls for additional reductions of NO_x and/or SO_2 to be achieved in two phases, 2009/2010 and 2015. On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating CAIR in its entirety and remanding it to the EPA for further action consistent with its opinion. On December 23, 2008, however, the U.S. Court of Appeals for the District of Columbia Circuit altered its July decision in response to a rehearing petition and remanded CAIR to the EPA without vacatur, thereby leaving CAIR compliance requirements in place while the EPA develops a revised rule. The State of Mississippi has an EPA-approved plan for implementing this rule. These reductions will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances. The full impact of the court's remand and the outcome of EPA's future rulemaking in response cannot be determined at this time.

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977 and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress by 2018 toward the natural conditions goal. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the Clean Air Visibility Rule allows states to determine that the CAIR satisfies BART requirements for SO_2 and NO_x. Extensive studies were performed for each of the Company's affected units to demonstrate that additional particulate matter controls are not necessary under BART. The states of Alabama and Mississippi have determined that no additional SO_2 controls necessary under BART. States have completed or are currently completing implementation plans that contain strategies for BART and any other measures required to achieve the first phase of reasonable progress.

The impacts of the eight-hour ozone and nonattainment designations, and the Clean Air Visibility Rule on the Company cannot be determined at this time and will depend on the resolution of any pending legal challenges and the development and implementation of rules at the state level.

The Company has developed and continually updates a comprehensive environmental compliance strategy to assess compliance obligations associated with the continuing and new environmental requirements discussed above. As part of this strategy, the Company plans to install additional SO_2 and NO_x emission controls within the next several years to ensure continued compliance with applicable air quality requirements.

In March 2005, the EPA published the final Clean Air Mercury Rule, a cap-and-trade program for the reduction of mercury emissions from coal-fired power plants. The final Clean Air Mercury Rule was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners alleged that the EPA was not authorized to establish a cap-and-trade program for mercury emissions and instead the EPA must establish maximum achievable control technology standards for coal-fired electric utility steam generating units. On February 8, 2008, the court ruled in favor of the petitioners and vacated the Clean Air Mercury Rule. The Company's overall environmental compliance strategy relies primarily on a combination of SO_2 and NOx controls to reduce mercury emissions. Any significant changes in the strategy will depend on the outcome of any appeals and/or future federal and state rulemakings. Future rulemakings necessitated by the court's decision could require emission reductions more stringent than those required by the Clean Air Mercury Rule.

Water Quality

In July 2004, the EPA published its final technology-based regulations under the Clean Water Act for the purpose of reducing impingement and entrainment of fish, shellfish, and other forms of aquatic life at existing power plant cooling water intake structures. The rules require baseline biological information and, perhaps, installation of fish protection technology near some intake structures at existing power plants. In January 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule, including the use of cost-benefit analysis, to the EPA for revisions. The decision has been appealed to the U.S. Supreme Court. The full impact of these regulations will depend on subsequent legal proceedings, further rulemaking by the EPA, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies and, therefore, cannot be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company could incur substantial costs to clean up properties. The Company conducts studies to determine the extent of any required cleanup and has recognized in its respective financial statements the costs to clean up known sites. Amounts for cleanup and ongoing monitoring costs were not material for any year presented. The Company could be liable for some or all required cleanup costs for additional sites that may require environmental remediation. See Note 3 to the financial statements under "Environmental Matters – Environmental Remediation" for additional information.

Global Climate Issues

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions and renewable energy standards continue to be strongly considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. The ultimate outcome of these proposals cannot be determined at this time; however, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In April 2007, the U.S. Supreme Court ruled that the EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that will follow from this response may have implications for both new and existing stationary sources, such as power plants. The ultimate outcome of these rulemaking activities cannot be determined at this time; however, as with the current legislative proposals, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In addition, some states are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. For example, on June 25, 2008, Florida's Governor signed comprehensive energy-related legislation that includes authorization for the Florida Department of Environmental Protection to adopt rules for a cap-and-trade regulatory program to address greenhouse gas emissions from electric utilities, conditioned upon their ratification by the legislature no sooner than the 2010 legislative session. This legislation also authorizes the Florida PSC to adopt a renewable portfolio standard for public utilities, subject to legislative ratification. The impact of any similar legislation on the Company will depend on the future development, adoption, legislative ratification, implementation, and potential legal challenges to rules governing greenhouse gas emissions and mandates regarding the use of renewable energy, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2012 timeframe, with a conclusion to this round of negotiations targeted for the end of 2009. The outcome and impact of the international negotiations cannot be determined at this time.

The Company is actively evaluating and developing electric generating technologies with lower greenhouse gas emissions. This includes the proposed construction of an advanced Integrated Coal Gasification Combined Cycle (IGCC) unit with approximately 50% carbon capture in Kemper County, Mississippi. The Company is currently considering additional projects and is pursuing research into the costs and viability of other renewable technologies for the Southeast.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $8.4 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Wholesale Rate Filing

On August 29, 2008, Mississippi Power filed with the FERC a request for revised wholesale electric tariff and rates. Prior to making this filing, Mississippi Power reached a settlement with all of its customers who take service under the tariff. This settlement agreement was filed with the FERC as part of the request. The settlement agreement provided for an increase in annual base wholesale revenues in the amount of $5.8 million, effective January 1, 2009. In addition, the settlement agreement allows Mississippi Power to increase its annual accrual for the wholesale portion of property damage to $303,000 per year, to defer any property damage costs prudently incurred in excess of the wholesale property damage reserve balance, and to defer the wholesale portion of the generation screening and evaluation costs associated with the IGCC project to be located in Kemper County Mississippi. The settlement agreement also provided that Mississippi Power will not seek a change in wholesale full-requirements rates before November 1, 2010, except for changes associated with the fuel adjustment clause and the energy cost management clause, changes associated with property damages that exceed the amount in the wholesale property damage reserve, and changes associated with costs and expenses associated with environmental requirements affecting fossil fuel generating facilities. On October 24, 2008, Mississippi

Power received notice that the FERC had accepted the filing effective November 1, 2008, and the revised monthly charges were applied beginning January 1, 2009. As result of the order, the Company reclassified $9.3 million of previously expensed generation screening and evaluation costs to a regulatory asset. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

PSC Matters

Statewide Electric Generation Needs Review

On April 30, 2008, in accordance with the Mississippi Public Utility Act, the Mississippi PSC issued an order to develop, publicize, and keep current an analysis of the five-year long-range needs for expansion of facilities for the generation of electricity in the State of Mississippi. In its order, the Mississippi PSC directed all affected utilities to submit evidence in support of their forecasts and plans in accordance with the Mississippi PSC's Public Utilities Rules of Practice and Procedure. Comments were filed on June 10, 2008, and hearings were held in August 2008. On January 16, 2009, the Company filed for a request for a Certificate of Public Convenience to construct generating capacity. The ultimate outcome of this matter cannot now be determined. See Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for additional information.

Mississippi Base Load Construction Legislation

In the 2008 regular session of the Mississippi legislature, a bill was passed and signed by the Governor on May 9, 2008 to enhance the Mississippi PSC's authority to facilitate development and construction of base load generation in the State of Mississippi (Baseload Act). The Baseload Act authorizes, but does not require, the Mississippi PSC to adopt a cost recovery mechanism that includes in retail base rates, prior to and during construction, all or a portion of the prudently incurred pre-construction and construction costs incurred by a utility in constructing a base load electric generating plant. Prior to the passage of the Baseload Act, such costs would traditionally be recovered only after the plant was placed in service. The Baseload Act also provides for periodic prudence reviews by the Mississippi PSC and prohibits the cancellation of any such generating plant without the approval of the Mississippi PSC. In the event of cancellation of the construction of the plant without approval of the Mississippi PSC, the Baseload Act authorizes the Mississippi PSC to make a public interest determination as to whether and to what extent the utility will be afforded rate recovery for costs incurred in connection with such cancelled generating plant. The effect of this legislation on Mississippi Power cannot now be determined.

Performance Evaluation Plan

In May 2004, the Mississippi PSC approved the Company's request to reclassify 266 megawatts of Plant Daniel Units 3 and 4 capacity to jurisdictional cost of service effective January 1, 2004, and authorized the Company to include the related costs and revenue credits in jurisdictional rate base, cost of service, and revenue requirement calculations for purposes of retail rate recovery. In the May 2004 order establishing the Company's forward-looking Rate Schedule PEP, the Mississippi PSC ordered that the Mississippi Public Utilities Staff and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and is currently ongoing. The outcome of this review cannot now be determined.

In April 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning January 1, 2007, and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2007, the Company had incurred and deferred the retail portion of $9.5 million of such costs. At December 31, 2008, the Company had a balance of the deferred retail portion of $7.1 million with $2.4 million included in current assets as other regulatory assets and $4.7 million included in long-term other regulatory assets.

In December 2007, the Company submitted its annual PEP filing for 2008, which resulted in a rate increase of 1.983% or $15.5 million annually, effective January 2008. In December 2006, the Company submitted its annual PEP filing for 2007, which resulted in no rate change.

In December 2007, the Company received an order from the Mississippi PSC requiring it to defer $1.4 million associated with the retail portion of certain tax credits and favorable adjustments related to permanent differences pertaining to its 2006 income tax returns filed in September 2007. These tax differences were recorded in a regulatory liability included in the current portion of other regulatory liabilities and were amortized ratably over the twelve month period beginning January 2008.

On March 14, 2008, the Company submitted its annual PEP lookback filing for 2007, which recommended no surcharge or refund. At the conclusion of the Mississippi Public Utilities Staff's review of the PEP lookback filing for 2007, the Company and the Mississippi Public Utilities Staff jointly submitted a stipulation to the Mississippi PSC which recommended no surcharge or refund.

The Mississippi Public Utilities Staff, pursuant to the Mississippi PSC's 2004 order approving the current PEP plan, is reviewing PEP to determine if any modifications should be made to the plan. Concurrent with this review, the annual PEP evaluation filing for 2009 was delayed by order of the Mississippi PSC and was scheduled to be filed on or before March 9, 2009. On February 23, 2009, however, the Company requested that the Mississippi PSC issue an order suspending the 2009 PEP evaluation filing to continue the scheduled review of the plan. The Company does not anticipate that suspending the PEP filing for 2009 will have a material impact on 2009 earnings. The Company anticipates that, as a result of the required review, changes to the plan will be made. Annual evaluations would resume for 2010 under a revised PEP plan. The final outcome cannot be determined at this time. See Note 3 to the financial statements under "Retail Regulatory Matters – Performance Evaluation Plan" for more information on PEP.

System Restoration Rider

In September 2006, the Company filed with the Mississippi PSC a request to implement a SRR to increase the Company's cap on the property damage reserve and to authorize the calculation of an annual property damage accrual based on a formula. The purpose of the SRR is to provide for recovery of costs associated with property damage (including certain property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. In November 2007, the Company along with the Mississippi Public Utilities Staff agreed and stipulated to a revised SRR calculation method that would no longer require the Mississippi PSC to set a cap on the property damage reserve or to authorize the calculation of an annual property damage accrual. Under the revised SRR calculation method, the Mississippi PSC would periodically agree on SRR revenue levels that would be developed based on historical data, expected exposure, type and amount of insurance coverage excluding insurance costs, and other relevant information.

On January 9, 2009, the Mississippi PSC issued an order accepting the stipulation and the revised SRR calculation method. The applicable SRR rate level will be adjusted every three years, unless a significant change in circumstances occurs such that the Company and the Mississippi Public Utilities Staff or the Mississippi PSC deems that a more frequent change would be appropriate. The Company will submit annual filings setting forth SRR-related revenues, expenses and investment for the projected filing period, as well as the true-up for the prior period. As a result the December 2008 retail regulatory liability of $6.8 million was reclassified to the property damage reserve. On February 2, 2009, the Company submitted its 2009 SRR rate filing with the Mississippi PSC, which proposed that the 2009 SRR rate level remain at zero and the Company be allowed to accrue approximately $4.0 million to the property damage reserve in 2009. The final outcome of this matter cannot now be determined.

Environmental Compliance Overview Plan

On February 3, 2009, the Company submitted its 2009 ECO Plan Notice which proposes an increase of 19 cents per 1,000 KWH for residential customers. The final outcome of this matter cannot now be determined. On February 1, 2008, the Company filed with the Mississippi PSC its annual ECO Plan evaluation for 2008. After the filing of the ECO Plan evaluation, the regulations addressing mercury emissions were altered by a decision issued by the U.S. Court of Appeals for the District of Columbia Circuit on February 8, 2008. On April 7, 2008, the Company filed with the Mississippi PSC a supplemental ECO Plan evaluation in which the projects included in the ECO Plan evaluation on February 1, 2008 being undertaken primarily for mercury control were removed. In this supplemental ECO Plan filing, the Company requested a 15 cent per 1,000 KWH decrease for retail residential customers. The Mississippi PSC approved the supplemental ECO Plan evaluation on June 11, 2008, with the new rates effective in June 2008. In April 2007, the Mississippi PSC approved the Company's 2007 ECO Plan, which included an 86 cents per 1,000 KWH increase for retail residential customers. This increase represented an addition of approximately $7.5 million in annual revenues for the Company. The new rates were effective in April 2007.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. Over the past several years, the Company has continued to experience higher than expected fuel costs for coal and natural gas. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; such filing occurred in November 2008. On December 29, 2008, the Mississippi PSC held a hearing on the Company's proposed increase in its fuel cost recovery factor. On February 11, 2009, the hearing examiner submitted a formal recommendation to the Mississippi PSC for approval of the factor as filed, with recovery proposed for the remaining calendar months of 2009. Any over or under recovery of fuel costs for 2009 would be addressed in the

Company's 2010 fuel cost recovery filing. The recommendation is under review by the Mississippi PSC at this time; therefore, the final outcome of this matter cannot now be determined. The proposed retail fuel cost recovery factor will result in an annual increase in an amount equal to 12.2% of total 2008 retail revenue. At December 31, 2008, the amount of under recovered retail fuel costs included in the balance sheet was $36.0 million compared to $24.5 million at December 31, 2007. The Company also has a wholesale Municipal and Rural Associations (MRA) and Market Base (MB) fuel cost recovery factor. Effective January 1, 2009, the wholesale MRA fuel rate increased resulting in an annual increase in an amount equal to 13.9% of total 2008 MRA revenue. Effective February 1, 2009, the wholesale MB fuel rate increased resulting in an annual increase in an amount equal to 16.7% of total 2008 MB revenue. At December 31, 2008, the amount of under recovered wholesale MRA and MB fuel costs included in the balance sheets was $15.4 million and $3.7 million compared to $13.7 million and $2.3 million, respectively, at December 31, 2007. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this increase to the billing factor will have no significant effect on the Company's revenues or net income, but will increase annual cash flow.

On October 7, 2008, the Mississippi PSC opened a docket to investigate and review interest and carrying charges under the fuel adjustment clause for utilities within the State of Mississippi including the Company. A hearing was held November 6, 2008 to hear testimony regarding the method of calculating carrying charges on over and under recoveries of fuel-related costs. The ultimate outcome of this matter cannot now be determined.

Storm Damage Cost Recovery

In August 2005, Hurricane Katrina hit the Gulf Coast of the United States and caused significant damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Katrina through December 31, 2007 of $302.4 million, which was net of expected insurance proceeds of approximately $77 million, without offset for the property damage reserve of $3.0 million, was affirmed by the Mississippi PSC in June 2006, and the Company was ordered to establish a regulatory asset for the retail portion. The Mississippi PSC issued an order directing the Company to file an application with the MDA for a CDBG. In October 2006, the Company received from the MDA a CDBG in the amount of $276.4 million, which was allocated to both the retail and wholesale jurisdictions. In the same month, the Mississippi PSC issued a financing order that authorized the issuance of system restoration bonds for the remaining $25.2 million of the retail portion of storm recovery costs not covered by the CDBG. These funds were received in June 2007. The Company affirmed the $302.4 million total storm costs incurred as of December 31, 2007. The Company plans to file with the Mississippi PSC its final accounting of the restoration cost relating to Hurricane Katrina and the storm operations center by the end of the first quarter 2009, at which time the final net retail receivable of approximately $3.2 million is expected to be recovered.

Income Tax Matters

Legislation

On February 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA include an extension of bonus depreciation and multiple renewable energy incentives. These incentives could have a significant impact on the Company's future cash flow and net income. Additionally, the ARRA includes programs for renewable energy, transmission and smart grid enhancement, fossil energy and research, and energy efficiency and conservation. The ultimate impact cannot be determined at this time.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in Section 199 (production activities deduction) of the Internal Revenue Code of 1986 as amended (Internal Revenue Code). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The Internal Revenue Service (IRS) has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction to conform to the agreement. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Integrated Coal Gasification Combined Cycle

On January 16, 2009, the Company filed for a Certificate of Public Convenience and Necessity with the Mississippi PSC to allow construction of a new electric generating plant located in Kemper County, Mississippi. The plant would utilize an advanced coal IGCC with an output capacity of 582 megawatts. The Kemper IGCC will use locally mined lignite (an abundant, lower heating value coal) from a proposed mine adjacent to the plant as fuel. This certificate, if approved by the Mississippi PSC, would authorize the Company to acquire, construct and operate the Kemper IGCC and related facilities. The Kemper IGCC, subject to federal and state environmental reviews and certain regulatory approvals, is expected to begin commercial operation in November 2013. As part of its filing, the Company has requested certain rate recovery treatment in accordance with the base load construction legislation. See FUTURE EARNINGS POTENTIAL – "PSC Matters – Mississippi Base Load Construction Legislation" herein for additional information.

The Company filed an application in June 2006 with the U.S. Department of Energy (DOE) for certain tax credits available to projects using clean coal technologies under the Energy Policy Act of 2005. The DOE subsequently certified the Kemper IGCC, and in November 2006 the IRS allocated Internal Revenue Code Section 48A tax credits of $133 million to the Company. The utilization of these credits is dependent upon meeting the certification requirements for the Kemper IGCC, including an in-service date no later than November 2013. The Company has secured all environmental reviews and permits necessary to commence construction of the Kemper IGCC and has entered into a binding contract for the steam turbine generator, completing two milestone requirements for the Section 48A credits.

On February 14, 2008, the Company also requested that the DOE transfer the remaining funds previously granted to a cancelled Southern Company project that would have been located in Orlando, Florida. On December 12, 2008, an agreement was reached to assign the remaining funds to the Kemper IGCC. The estimated construction cost of the Kemper IGCC is approximately $2.2 billion, which is net of $220 million related to funding to be received from the DOE related to project construction. The remaining DOE funding of $50 million is projected to be used for demonstration over the first few years of operation.

Beginning in December 2006, the Mississippi PSC has approved the Company's requested accounting treatment to defer the costs associated with the Company's generation resource planning, evaluation, and screening activities as a regulatory asset. On December 22, 2008, the Company requested an amendment to its original order that would allow these costs to continue to be charged to and remain in a regulatory asset until January 1, 2010. In its application, the Company reported that it anticipated spending approximately $61 million by or before May 31, 2009. At December 31, 2008, the Company had spent $42.3 million of the $61 million, of which $3.7 million related to land purchases capitalized. Of the remaining amount, $0.8 million was expensed and $37.8 million was deferred in other regulatory assets.

The final outcome of this matter cannot now be determined.

Other Matters

On February 15, 2008, the Company received notice of termination from South Mississippi Electric Power Association (SMEPA) of an approximately 100 MW territorial wholesale market based contract effective March 31, 2011 which will result in a decrease in annual revenues of approximately $12 million. On December 17, 2008, the Company entered into a 10-year power supply agreement with SMEPA for approximately 152 MW. This contract is effective April 1, 2011, upon approval from the U.S. Department of Agriculture's Rural Utilities Service. This contract is expected to increase the Company's annual territorial wholesale base revenues by approximately $16.1 million.

The Company is involved in various other matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Electric Utility Regulation

The Company is subject to retail regulation by the Mississippi PSC and wholesale regulation by the FERC. These regulatory agencies set the rates the Company is permitted to charge customers based on allowable costs. As a result, the Company applies Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71), which requires the financial statements to reflect the effects of rate regulation. Through the ratemaking process, the regulators may require the inclusion of costs or revenues in periods different than when they would be recognized by a non-regulated company. This treatment may result in the deferral of expenses and the recording of related regulatory assets based on anticipated future recovery through rates or the deferral of gains or creation of liabilities and the recording of related regulatory liabilities. The application of SFAS No. 71 has a further effect on the Company's financial statements as a result of the estimates of allowable costs used in the ratemaking process. These estimates may differ from those actually incurred by the Company; therefore, the accounting estimates inherent in specific costs such as depreciation and pension and postretirement benefits have less of a direct impact on the Company's results of operations than they would on a non-regulated company.

As reflected in Note 1 to the financial statements, significant regulatory assets and liabilities have been recorded. Management reviews the ultimate recoverability of these regulatory assets and liabilities based on applicable regulatory guidelines and accounting principles generally accepted in the United States. However, adverse legislative, judicial, or regulatory actions could materially impact the amounts of such regulatory assets and liabilities and could adversely impact the Company's financial statements.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with generally accepted accounting principles, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters;
- Changes in existing income tax regulations or changes in IRS or state revenue department interpretations of existing regulations;
- Identification of additional sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party;
- Identification and evaluation of new or other potential lawsuits or complaints in which the Company may be named as a defendant;
- Resolution or progression of existing matters through the legislative process, the court systems, the IRS, the FERC, or the EPA.

Unbilled Revenues

Revenues related to the retail sale of electricity are recorded when electricity is delivered to customers. However, the determination of KWH sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of electricity delivered to customers, but not yet metered and billed, are estimated. Components of the unbilled revenue estimates include total KWH territorial supply, total KWH billed, estimated total electricity lost in delivery, and customer usage. These components can fluctuate as a result of a number of factors including weather, generation patterns, and power delivery volume and other operational constraints. These factors can be unpredictable and can vary from historical trends. As a result, the overall estimate of unbilled revenues could be significantly affected, which could have a material impact on the Company's results of operations.

Plant Daniel Operating Lease

As discussed in Note 7 to the financial statements under "Operating Leases – Plant Daniel Combined Cycle Generating Units," the Company leases a 1,064 megawatt natural gas combined cycle facility at Plant Daniel (Facility) from Juniper Capital L.P. (Juniper). For both accounting and rate recovery purposes, this transaction is treated as an operating lease, which means that the related obligations under this agreement are not reflected in the balance sheets. See FINANCIAL CONDITION AND LIQUIDITY – "Off-Balance Sheet Financing Arrangements" herein for further information. The operating lease determination was based on assumptions and estimates related to the following:

- Fair market value of the Facility at lease inception;
- The Company's incremental borrowing rate;
- Timing of debt payments and the related amortization of the initial acquisition cost during the initial lease term;
- Residual value of the Facility at the end of the lease term;
- Estimated economic life of the Facility; and
- Juniper's status as a voting interest entity.

The determination of operating lease treatment was made at the inception of the lease agreement and is not subject to change unless subsequent changes are made to the agreement. However, the Company is also required to monitor Juniper's ongoing status as a voting interest entity. Changes in that status could require the Company to consolidate the Facility's assets and the related debt and to record interest and depreciation expense of approximately $37 million annually, rather than annual lease expense of approximately $26 million.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2008. Throughout the recent turmoil in the financial markets, the Company has maintained adequate access to capital without drawing on any of its committed bank credit arrangements used to support its commercial paper programs and variable rate pollution control revenue bonds. The Company has continued to issue commercial paper at reasonable rates. The Company intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements to meet future capital and liquidity needs. No material changes in bank credit arrangements have occurred although market rates for committed credit have increased and the Company may be subject to higher costs as its existing facilities are replaced or renewed. The Company's interest cost for short-term debt has decreased as market short-term interest rates have declined. The Company experienced no material counterparty credit losses as a result of the turmoil in the financial markets. The ultimate impact on future financing costs as a result of the financial turmoil cannot be determined at this time. See "Sources of Capital" and "Financing Activities" herein for additional information.

The Company's investments in pension trust funds declined in value as of December 31, 2008. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time.

Net cash provided from operating activities decreased from 2007 by $112.2 million. The decrease in net cash provided from operating activities was primarily due to the receipt of grant proceeds of $74.3 million in June 2007 and a decrease in operating activities related to receivables in 2008 in the amount of $49.5 million. The decrease in receivables is primarily due to the change in under recovered regulatory clause revenues of $24.7 million and a $24.1 change in affiliate receivables. Also impacting operating activities were decreases related to fossil fuel stock of $33.3 million primarily due to increases in coal and coal in-transit of $22.0 million and $15.6 million, respectively. These were offset by an increase in deferred income taxes and investment tax credits of $61.4 million. Net cash flow from operating activities increased in 2007 compared to 2006 by $11.7 million primarily due to the Company's receipt of $74.3 million in bond proceeds during 2007 related to Hurricane Katrina recovery, of which $60 million was used to fund the property damage reserve and $14.3 million to recover retail operations and maintenance storm restoration cost. The $153.0 million increase in net cash from operating activities for 2006 compared to 2005 resulted primarily from $120.3 million received from the CDBG program.

The $55.3 million increase in net cash used for investing activities in 2008 was primarily due to a $12.1 million increase in construction payables and a $27.6 million increase due to the capital portion of Hurricane Katrina grant proceeds received in 2007. The change in net cash used for investing activities in 2007 compared to 2006 of $107.0 million was primarily due to a $117.8 million reduction in the sources of funds related to Hurricane Katrina capital related grant proceeds received in 2006 and bond proceeds. The change in net cash provided from investing activities in 2006 compared to 2005 of $176.9 million was primarily due to a $152.8 million receipt of capital related grant and bond proceeds related to Hurricane Katrina.

Net cash provided from financing activities totaled $78.9 million in 2008 compared to $105.5 million that was used in financing activities for the corresponding period in 2007. The $184.5 million increase in net cash provided from financing activities was primarily due to the $80 million long-term bank loan issued to the Company in March 2008, the $50 million senior notes issued in November 2008 and the $36 million redemption of the long-term debt to an affiliated trust in the first nine months of 2007. Notes payable increased by $57.8 million primarily due to additional borrowings from commercial paper. Net cash used for financing activities totaled $105.5 million in 2007 compared to $211.5 million in 2006. This decrease in net cash used for financing activities is primarily due to a decrease in the use of funds related to notes payable of $109.3 million. Net cash used for financing activities totaled $211.5 million in 2006 compared to net cash provided from financing activities of $135.9 million in 2005. This increase in net cash used for financing activities is primarily due to an increase in the use of funds related to notes payable of $352.9 million.

Significant changes in the balance sheet as of December 31, 2008, compared to 2007 include an increase in fossil fuel inventory of $38.1 million primarily due to increases in coal and coal in-transit of $22.0 million and $15.6 million, respectively. Other regulatory assets increased $135.9 million primarily due to mark to market losses on forward gas contracts and the change in the market value of pension plan assets. Prepaid pension cost decreased $66.1 million due to the decline in the market value of pension plan assets. Securities due within one year increased by $40.1 million due to senior notes maturing in 2009. Long-term debt increased by $88.5 million primarily due to an $80 million long-term bank loan issued to the Company in March 2008 and $50 million in senior notes issued in November 2008, partially offset by the $36 million redemption of the long-term debt to an affiliated trust in 2007. The increase in employee benefit obligations of $53.9 million and the decrease in other regulatory liabilities of $68.1 million were primarily due to the decline in the market value of pension assets. See Note 2 to the financial statements under "Pension Plans" for additional information.

The Company's ratio of common equity to total capitalization, excluding long-term debt due within one year, decreased from 66.1% in 2007 to 61.2% at December 31, 2008. The Company has received investment grade credit ratings from the major rating agencies with respect to debt, preferred securities, and preferred stock. See SELECTED FINANCIAL AND OPERATING DATA for additional information regarding the Company's security ratings.

Sources of Capital

The Company plans to obtain the funds required for construction, and other purposes from sources such as operating cash flows, security issuances, term loans, short-term borrowings and capital contributions from Southern Company. See "Capital Requirements and Contractual Obligations" herein and Note 3 to the financial statements under "Integrated Coal Gasification Combined Cycle" for

additional information. The amount, type, and timing of any financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

The issuance of securities by the Company is subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

The Company obtains financing separately without credit support from any affiliate. The Southern Company system does not maintain a centralized cash or money pool. Therefore, funds of the Company are not commingled with funds of any other company.

To meet short-term cash needs and contingencies, the Company has various sources of liquidity. At December 31, 2008, the Company had approximately $22.4 million of cash and cash equivalents and $98.5 million of unused credit arrangements with banks. Subsequent to December 31, 2008, the Company increased an existing credit agreement by $10 million. The facility matures in the third quarter of 2009 and allows for the execution of a two year term loan. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company may also meet short-term cash needs through a Southern Company subsidiary organized to issue and sell commercial paper at the request and for the benefit of the Company and the other traditional operating companies. Proceeds from such issuances for the benefit of the Company are loaned directly to the Company and are not commingled with proceeds from such issuances for the benefit of any other operating company. The obligations of each company under these arrangements are several; there is no cross affiliate credit support. At December 31, 2008, the Company had $26.3 million of commercial paper outstanding.

Financing Activities

During the fourth quarter of 2008, the Company issued senior notes totaling $50 million. Proceeds were used to repay a portion of the Company's short-term indebtedness.

In September 2008, the Company was required to purchase a total of approximately $7.9 million of variable rate pollution control revenue bonds that were tendered by investors. In December 2008, the bonds were successfully remarketed.

Also during 2008, the Company entered into a three-year term loan agreement of $80 million. Proceeds were used to repay a portion of the Company's short-term indebtedness and for other corporate purposes, including the Company's continuous construction program.

In addition to any financings that may be necessary to meet capital requirements and contractual obligations, the Company plans to continue, when economically feasible, a program to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

Off-Balance Sheet Financing Arrangements

In 2001, the Company began an initial 10-year term of a lease agreement for a combined cycle generating facility built at Plant Daniel. In June 2003, the Company entered into a restructured lease agreement for the Facility with Juniper, as discussed in Note 7 to the financial statements under "Operating Leases – Plant Daniel Combined Cycle Generating Units." Juniper has also entered into leases with other parties unrelated to the Company. The assets leased by the Company comprise less than 50% of Juniper's assets. The Company does not consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. Accordingly, the lease is not reflected in the balance sheets.

The initial lease term ends in 2011, and the lease includes a renewal and a purchase option based on the cost of the Facility at the inception of the lease, which was approximately $370 million. The Company is required to amortize approximately 4% of the initial acquisition cost over the initial lease term. Eighteen months prior to the end of the initial lease, the Company may elect to renew for 10 years. If the lease is renewed, the agreement calls for the Company to amortize an additional 17% of the initial completion cost over the renewal period. Upon termination of the lease, at the Company's option, it may either exercise its purchase option or the Facility can be sold to a third party.

The lease also provides for a residual value guarantee, approximately 73% of the acquisition cost, by the Company that is due upon termination of the lease in the event that the Company does not renew the lease or purchase the Facility and that the fair market value is less than the unamortized cost of the Facility.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, emissions allowances and energy price risk management. At December 31, 2008, the maximum potential collateral requirements under these contracts at BBB- and/or Baa3 rating were approximately $6 million. At December 31, 2008, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $149 million. Included in these amounts are certain agreements that could require collateral in the event that one or more power pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

Market Price Risk

Due to cost-based rate regulation, the Company has limited exposure to market volatility in interest rates, commodity fuel prices, and prices of electricity. To manage the volatility attributable to these exposures, the Company nets the exposures, where possible, to take advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. The Company's policy is that derivatives are to be used primarily for hedging purposes and mandates strict adherence to all applicable risk management policies. Derivative positions are monitored using techniques that include, but are not limited to, market valuation, value at risk, stress testing, and sensitivity analysis.

The Company does not currently hedge interest rate risk. The weighted average interest rate on $160 million of variable rate long-term debt at December 31, 2008 was 1.79%. If the Company sustained a 100 basis point change in interest rates for all unhedged variable rate long-term debt, the change would affect annualized interest expense by approximately $1.6 million at December 31, 2008. See Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

To mitigate residual risks relative to movements in electricity prices, the Company enters into fixed-price contracts for the purchase and sale of electricity through the wholesale electricity market. At December 31, 2008, exposure from these activities was not material to the Company's financial statements.

In addition, per the guidelines of the Mississippi PSC, the Company has implemented a fuel-hedging program. At December 31, 2008, exposure from these activities was not material to the Company's financial statements.

The changes in fair value of energy-related derivative contracts were as follows at December 31:

	2008 Changes	2007 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	**$ 2.0**	$(6.3)
Contracts realized or settled	**(30.7)**	2.5
Current period changes[(a)]	**(23.3)**	5.8
Contracts outstanding at the end of the period, assets (liabilities), net	**$(52.0)**	$ 2.0

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

The decrease in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2008 was $54.0 million, substantially, all of which is due to natural gas positions. This change is attributable to both the volume and prices of natural gas. At December 31, 2008, the Company had a net hedge volume of 28.9 billion cubic feet (Bcf) with a weighted average contract cost approximately $1.89 per million British thermal units (mmBtu) above market prices, and 15.6 Bcf at December 31, 2007 with a

weighted average contract cost approximately $0.09 per mmBtu below market prices. The majority of the natural gas hedges are recovered through the Company's fuel cost recovery clauses.

At December 31, 2008, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

	2008	2007
	(in millions)	
Regulatory hedges	$(52.0)	$1.3
Cash flow hedges	-	0.9
Non-accounting hedges	-	(0.2)
Total fair value	$(52.0)	$2.0

Energy-related derivative contracts which are designated as regulatory hedges significantly relate to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost management clause. Gains and losses on energy-related derivatives designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred. The pre-tax gains/(losses) reclassified from other comprehensive income to revenue and fuel expense were not material for any period presented and are not expected to be material for 2009. Additionally, there was no material ineffectiveness recorded in earnings for any period presented. The Company has energy-related hedges in place up to and including 2012.

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented.

The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

	December 31, 2008 Fair Value Measurements			
	Total	Maturity		
	Fair Value	Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ -	$ -	$ -	$ -
Level 2	(52.0)	(27.9)	(19.0)	(5.1)
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$(52.0)	$(27.9)	$(19.0)	$(5.1)

As part of the adoption of FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) to increase consistency and comparability in fair value measurements and related disclosures, the table above now uses the three-tier fair value hierarchy, as discussed in Note 9 to the financial statements, as opposed to the previously used descriptions "actively quoted," "external sources," and "models and other methods." The three-tier fair value hierarchy focuses on the fair value of the contract itself, whereas the previous descriptions focused on the source of the inputs. Because the Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, the valuations of those contracts now appear in Level 2; previously they were shown as "actively quoted."

The Company is exposed to market price risk in the event of nonperformance by counterparties to the energy-related derivative contracts. The Company's practice is to enter into agreements with counterparties that have investment grade credit ratings by Moody's and Standard & Poor's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The construction program of the Company is currently estimated to be $163 million for 2009, $467 million for 2010, and $1,004 million for 2011. These estimates include costs for new generation construction. Environmental expenditures included in these estimated amounts are $28 million, $61 million, and $111 million for 2009, 2010, and 2011, respectively. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; storm impacts; changes in environmental statutes and regulations; changes in FERC rules and regulations; Mississippi PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered.

In addition, as discussed in Note 2 to the financial statements, the Company provides postretirement benefits to substantially all employees and funds trusts to the extent required by the FERC.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, derivative obligations, preferred stock dividends, leases, and other purchase commitments, are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2009	2010-2011	2012-2013	After 2013	Total
			(in thousands)		
Long-term debt[a] –					
Principal	$ 41,230	$ 82,767	$ 50,633	$237,695	$ 412,325
Interest	17,016	31,884	28,920	185,393	263,213
Preferred stock dividends[b]	1,733	3,465	3,465	-	8,663
Energy-related derivative obligations[c]	29,291	18,939	5,118	-	53,348
Operating leases[d]	40,149	62,486	2,133	2,223	106,991
Purchase commitments[e] –					
Capital[f]	162,817	1,471,106	-	-	1,633,923
Coal	368,572	298,787	86,800	7,800	761,959
Natural gas[g]	191,576	194,642	44,608	204,944	635,770
Long-term service agreements[h]	11,884	24,410	25,147	99,738	161,179
Postretirement benefits trust[i]	125	251	-	-	376
Total	$864,393	$2,188,737	$246,824	$737,793	$4,037,747

(a) All amounts are reflected based on final maturity dates. The Company plans to continue to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit. Variable rate interest obligations are estimated based on rates as of January 1, 2008, as reflected in the statements of capitalization.

(b) Preferred stock does not mature; therefore, amounts are provided for the next five years only.

(c) For additional information, see Notes 1 and 6 to the financial statements.

(d) The decrease from 2010-2011 to 2012-2013 is primarily a result of the Daniel Operating lease contract that is scheduled to end during 2011.

(e) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for 2008, 2007, and 2006 were $260 million, $255 million, and $237 million, respectively.

(f) The Company forecasts capital expenditures over a three-year period. Amounts represent current estimates of total expenditures. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program.

(g) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on the New York Mercantile Exchange future prices at December 31, 2008.

(h) Long-term service agreements include price escalation based on inflation indices.

(i) The Company forecasts postretirement trust contributions over a three-year period. The Company expects that the earliest that cash may have to be contributed to the pension trust fund is 2011 and such contribution could be significant; however, projections of the amount vary significantly depending on interpretations of and decisions related to federal legislation passed during 2008 as well as other key variables including future trust fund performance and cannot be determined at this time. Therefore, no amounts related to the pension trust fund are included in the table. See Note 2 to the financial statements for additional information related to the pension and postretirement plans, including estimated benefit payments. Certain benefit payments will be made through the related trusts. Other benefit payments will be made from the Company's corporate assets.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2008 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning retail sales growth, retail rates, storm damage cost recovery and repairs, fuel cost recovery and other rate actions, environmental regulations and expenditures, access to sources of capital, projections for postretirement benefit trust contributions, financing activities, impacts of the adoption of new accounting rules, completion of construction projects, estimated sales and purchases under new power sale and purchase agreements, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized.
These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters and EPA civil actions;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- ability to control costs;
- investment performance of the Company's employee benefit plans;
- advances in technology;
- state and federal rate regulations and the impact of pending and future rate cases and negotiations, including rate actions relating to fuel and storm restoration cost recovery;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with neighboring utilities;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

STATEMENTS OF INCOME

For the Years Ended December 31, 2008, 2007, and 2006

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	2008	2007	2006
		(in thousands)	
Operating Revenues:			
Retail revenues	**$785,434**	$727,214	$647,186
Wholesale revenues --			
Non-affiliates	**353,793**	323,120	268,850
Affiliates	**100,928**	46,169	76,439
Other revenues	**16,387**	17,241	16,762
Total operating revenues	**1,256,542**	1,113,744	1,009,237
Operating Expenses:			
Fuel	**586,503**	494,248	438,622
Purchased power --			
Non-affiliates	**27,036**	9,188	16,292
Affiliates	**99,526**	86,690	56,955
Other operations and maintenance	**260,011**	255,177	236,692
Depreciation and amortization	**71,039**	60,376	46,853
Taxes other than income taxes	**65,099**	60,328	60,904
Total operating expenses	**1,109,214**	966,007	856,318
Operating Income	**147,328**	147,737	152,919
Other Income and (Expense):			
Interest income	**1,998**	1,986	4,272
Interest expense, net of amounts capitalized	**(17,978)**	(18,158)	(18,639)
Other income (expense), net	**4,694**	6,029	(6,712)
Total other income and (expense)	**(11,286)**	(10,143)	(21,079)
Earnings Before Income Taxes	**136,042**	137,594	131,840
Income taxes	**48,349**	51,830	48,097
Net Income	**87,693**	85,764	83,743
Dividends on Preferred Stock	**1,733**	1,733	1,733
Net Income After Dividends on Preferred Stock	**$ 85,960**	$ 84,031	$ 82,010

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007, and 2006
Mississippi Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Activities:			
Net income	**$ 87,693**	$ 85,764	$ 83,743
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**75,765**	69,971	68,198
Deferred income taxes and investment tax credits, net	**24,840**	(36,572)	(47,535)
Plant Daniel capacity	**-**	(5,659)	(13,008)
Pension, postretirement, and other employee benefits	**8,182**	8,782	5,650
Stock based compensation expense	**724**	1,038	1,057
Tax benefit of stock options	**489**	287	258
Hurricane Katrina grant proceeds-property reserve	**-**	60,000	-
Wholesale generation construction screening expense	**(9,284)**	-	-
Other, net	**(38,145)**	(24,814)	(5,761)
Changes in certain current assets and liabilities --			
Receivables	**(24,432)**	25,107	64,976
Fossil fuel stock	**(38,072)**	(4,787)	7,765
Materials and supplies	**297**	487	750
Prepaid income taxes	**3,243**	17,727	20,247
Other current assets	**(2,022)**	(1,923)	(6,560)
Hurricane Katrina grant proceeds	**-**	14,345	120,328
Hurricane Katrina accounts payable	**-**	(53)	(50,512)
Other accounts payable	**3,251**	(4,525)	(30,419)
Accrued taxes	**2,428**	(867)	1,972
Accrued compensation	**(1,362)**	(1,993)	(629)
Over recovered regulatory clause revenues	**-**	-	(26,188)
Other current liabilities	**836**	4,343	634
Net cash provided from operating activities	**94,431**	206,658	194,966
Investing Activities:			
Property additions	**(153,401)**	(144,925)	(127,290)
Cost of removal net of salvage	**(6,411)**	2,195	(9,420)
Construction payables	**(4,084)**	8,027	(7,596)
Hurricane Katrina capital grant proceeds	**7,314**	34,953	152,752
Other	**819**	(755)	(1,992)
Net cash provided from (used for) investing activities	**(155,763)**	(100,505)	6,454
Financing Activities:			
Increase (decrease) in notes payable, net	**16,350**	(41,433)	(150,746)
Proceeds --			
Senior notes	**50,000**	35,000	-
Gross excess tax benefit of stock options	**934**	572	669
Capital contributions from parent company	**3,541**	5,436	5,503
Pollution control revenue bonds	**7,900**	-	-
Other long-term debt	**80,000**	-	-
Redemptions --			
Pollution control revenue bonds	**(7,900)**	-	-
Other long-term debt	**-**	(36,082)	-
Payment of preferred stock dividends	**(1,733)**	(1,733)	(1,733)
Payment of common stock dividends	**(68,400)**	(67,300)	(65,200)
Other	**(1,774)**	-	-
Net cash provided from (used for) financing activities	**78,918**	(105,540)	(211,507)
Net Change in Cash and Cash Equivalents	**17,586**	613	(10,087)
Cash and Cash Equivalents at Beginning of Year	**4,827**	4,214	14,301
Cash and Cash Equivalents at End of Year	**$ 22,413**	$ 4,827	$ 4,214
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $229, $12 and $- capitalized, respectively)	**$15,753**	$16,164	$29,288
Income taxes (net of refunds)	**23,829**	67,453	75,209

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2008 and 2007
Mississippi Power Company 2008 Annual Report

Assets	2008	2007
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 22,413**	$ 4,827
Receivables --		
Customer accounts receivable	**40,262**	43,946
Unbilled revenues	**24,798**	23,163
Under recovered regulatory clause revenues	**54,994**	40,545
Other accounts and notes receivable	**8,995**	5,895
Affiliated companies	**24,108**	11,838
Accumulated provision for uncollectible accounts	**(1,039)**	(924)
Fossil fuel stock, at average cost	**85,538**	47,466
Materials and supplies, at average cost	**27,143**	27,440
Prepaid income taxes	**1,061**	5,735
Other regulatory assets	**59,219**	32,234
Other	**9,838**	12,687
Total current assets	**357,330**	254,852
Property, Plant, and Equipment:		
In service	**2,234,573**	2,130,835
Less accumulated provision for depreciation	**923,269**	880,148
	1,311,304	1,250,687
Construction work in progress	**70,665**	50,015
Total property, plant, and equipment	**1,381,969**	1,300,702
Other Property and Investments	**8,280**	9,556
Deferred Charges and Other Assets:		
Deferred charges related to income taxes	**9,566**	8,867
Prepaid pension costs	**-**	66,099
Other regulatory assets	**171,680**	62,746
Other	**23,870**	24,843
Total deferred charges and other assets	**205,116**	162,555
Total Assets	**$1,952,695**	1,727,665

The accompanying notes are an integral part of these financial statements.

BALANCE SHEETS
At December 31, 2008 and 2007
Mississippi Power Company 2008 Annual Report

Liabilities and Stockholder's Equity	2008	2007
	(in thousands)	
Current Liabilities:		
Securities due within one year	**$ 41,230**	$ 1,138
Notes payable	**26,293**	9,944
Accounts payable --		
Affiliated	**36,847**	40,394
Other	**63,704**	60,758
Customer deposits	**10,354**	9,640
Accrued taxes --		
Income taxes	**8,842**	-
Other	**50,701**	48,853
Accrued interest	**3,930**	2,713
Accrued compensation	**20,604**	21,965
Other regulatory liabilities	**9,718**	11,082
Liabilities from risk management activities	**29,291**	3,754
Other	**19,143**	20,128
Total current liabilities	**320,657**	230,369
Long-term Debt (See accompanying statements)	**370,460**	281,963
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**222,324**	206,818
Deferred credits related to income taxes	**14,074**	15,156
Accumulated deferred investment tax credits	**14,014**	15,254
Employee benefit obligations	**142,188**	88,300
Other cost of removal obligations	**96,191**	90,485
Other regulatory liabilities	**51,340**	119,458
Other	**52,216**	33,252
Total deferred credits and other liabilities	**592,347**	568,723
Total Liabilities	**1,283,464**	1,081,055
Preferred Stock (See accompanying statements)	**32,780**	32,780
Common Stockholder's Equity (See accompanying statements)	**636,451**	613,830
Total Liabilities and Stockholder's Equity	**$1,952,695**	$1,727,665
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF CAPITALIZATION

At December 31, 2008 and 2007

Mississippi Power Company 2008 Annual Report

	2008	2007	2008	2007
	(in thousands)		*(percent of total)*	
Long-Term Debt:				
Long-term notes payable --				
6.00% due 2013	**$ 50,000**	$ -		
5.4% to 5.625% due 2017-2035	**155,000**	155,000		
Adjustable rates (1.645% to 2.36% at 1/1/09) due 2009-2011	**120,000**	40,000		
Total long-term notes payable	**325,000**	195,000		
Other long-term debt --				
Pollution control revenue bonds:				
5.15% due 2028	**42,625**	-		
Variable rates (1.20% to 1.60% at 1/1/09) due 2020-2028	**40,070**	82,695		
Total other long-term debt	**82,695**	82,695		
Capitalized lease obligations	**4,629**	5,768		
Unamortized debt discount	**(634)**	(362)		
Total long-term debt (annual interest requirement -- $17.0 million)	**411,690**	283,101		
Less amount due within one year	**41,230**	1,138		
Long-term debt excluding amount due within one year	**370,460**	281,963	**35.6%**	30.4%
Cumulative Preferred Stock:				
$100 par value				
Authorized: 1,244,139 shares				
Outstanding: 334,210 shares				
4.40% to 5.25%				
(annual dividend requirement -- $1.7 million)	**32,780**	32,780	**3.2**	3.5
Common Stockholder's Equity:				
Common stock, without par value --				
Authorized: 1,130,000 shares				
Outstanding: 1,121,000 shares	**37,691**	37,691		
Paid-in capital	**319,958**	314,324		
Retained earnings	**278,802**	261,242		
Accumulated other comprehensive income (loss)	**-**	573		
Total common stockholder's equity	**636,451**	613,830	**61.2**	66.1
Total Capitalization	**$1,039,691**	$928,573	**100.0%**	100.0%

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2008, 2007, and 2006

Mississippi Power Company 2008 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)		
Balance at December 31, 2005	$37,691	$299,536	$227,701	$(3,768)	$561,160
Net income after dividends on preferred stock	-	-	82,010	-	82,010
Capital contributions from parent company	-	7,483	-	-	7,483
Other comprehensive income (loss)	-	-	-	(180)	(180)
Adjustment to initially apply FASB Statement No. 158, net of tax	-	-	-	4,547	4,547
Cash dividends on common stock	-	-	(65,200)	-	(65,200)
Balance at December 31, 2006	37,691	307,019	244,511	599	589,820
Net income after dividends on preferred stock	-	-	84,031	-	84,031
Capital contributions from parent company	-	7,333	-	-	7,333
Other comprehensive income (loss)	-	-	-	(26)	(26)
Cash dividends on common stock	-	-	(67,300)	-	(67,300)
Other	-	(28)	-	-	(28)
Balance at December 31, 2007	**37,691**	**314,324**	**261,242**	**573**	**613,830**
Net income after dividends on preferred stock	-	-	**85,960**	-	**85,960**
Capital contributions from parent company	-	**5,634**	-	-	**5,634**
Other comprehensive income (loss)	-	-	-	**(573)**	**(573)**
Cash dividends on common stock	-	-	**(68,400)**	-	**(68,400)**
Other	-	-	-	-	-
Balance at December 31, 2008	**$37,691**	**$319,958**	**$278,802**	**$ -**	**$636,451**

The accompanying notes are an integral part of these financial statements.

STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Mississippi Power Company 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Net income after dividends on preferred stock	**$85,960**	$84,031	$82,010
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $(355), $(16), and $502, respectively	**(573)**	(26)	810
Pension and other postretirement benefit plans:			
Change in additional minimum pension liability, net of tax of $-, $-, and $(614), respectively	-	-	(990)
Total other comprehensive income (loss)	**(573)**	(26)	(180)
Comprehensive Income	**$85,387**	$84,005	$81,830

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Mississippi Power Company (the Company) is a wholly owned subsidiary of Southern Company, which is the parent company of four traditional operating companies, Southern Power Company (Southern Power), Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power Company (Alabama Power), Georgia Power Company (Georgia Power), Gulf Power Company (Gulf Power), and Mississippi Power Company (Mississippi Power), are vertically integrated utilities providing electric service in four Southeastern states. The Company operates as a vertically integrated utility providing service to retail customers in southeast Mississippi and to wholesale customers in the Southeast. Southern Power constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The equity method is used for entities in which the Company has significant influence but does not control and for variable interest entities where the Company is not the primary beneficiary.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC) and the Mississippi Public Service Commission (PSC). The Company follows accounting principles generally accepted in the United States and complies with the accounting policies and practices prescribed by its regulatory commissions. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

Reclassifications

Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. The statements of income for the prior periods presented have been modified within the operating expenses section to combine the line items "Other operations" and "Maintenance" into a single line item entitled "Other operations and maintenance." The balance sheet at December 31, 2007 was modified to present a separate line for "Liabilities for risk management activities" previously included in "Other." These reclassifications had no effect on total assets, net income, or cash flows.

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at direct or allocated cost: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, and other services with respect to business and operations and power pool transactions. Costs for these services amounted to $87 million, $71.8 million, and $55.2 million during 2008, 2007, and 2006, respectively. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

The Company provides incidental services to and receives such services from other Southern Company subsidiaries which are generally minor in duration and amount. The Company provided no significant service to an affiliate in 2008, 2007, and 2006. The Company received storm restoration assistance from other Southern Company subsidiaries totaling $3.2 million and $1.5 million in 2008 and 2006, respectively. There was no storm assistance received in 2007.

The Company has an agreement with Alabama Power under which the Company owns a portion of Greene County Steam Plant. Alabama Power operates Greene County Steam Plant, and the Company reimburses Alabama Power for its proportionate share of all associated expenditures and costs. The Company reimbursed Alabama Power for the Company's proportionate share of related expenses which totaled $11.1 million, $9.8 million, and $8.6 million in 2008, 2007, and 2006, respectively. The Company also has

an agreement with Gulf Power under which Gulf Power owns a portion of Plant Daniel. The Company operates Plant Daniel, and Gulf Power reimburses the Company for its proportionate share of all associated expenditures and costs. Gulf Power reimbursed the Company for Gulf Power's proportionate share of related expenses which totaled $22.8 million, $23.1 million, and $19.7 million in 2008, 2007, and 2006, respectively. See Note 4 for additional information.

The traditional operating companies, including the Company, and Southern Power may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS, as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements. See Note 7 under "Fuel Commitments" for additional information.

Regulatory Assets and Liabilities

The Company is subject to the provisions of Financial Accounting Standards Board (FASB) Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS No. 71). Regulatory assets represent probable future revenues associated with certain costs that are expected to be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are expected to be credited to customers through the ratemaking process.

Regulatory assets and (liabilities) reflected in the balance sheets at December 31 relate to:

	2008	2007	Note
		(in thousands)	
Hurricane Katrina	**$ (143)**	$ (143)	(a)
Underfunded retiree benefit plans	**87,094**	28,331	(b)
Property damage	**(54,241)**	(63,804)	(c)
Deferred income tax charges	**8,862**	9,486	(d)
Property tax	**16,333**	15,043	(e)
Transmission & distribution deferral	**7,101**	9,468	(f)
Vacation pay	**8,498**	7,736	(g)
Loss on reacquired debt	**9,133**	9,906	(h)
Loss on redeemed preferred stock	**400**	571	(i)
Loss on rail cars	**196**	274	(h)
Other regulatory assets	**-**	832	(c)
Fuel-hedging (realized and unrealized) losses	**56,516**	3,298	(j)
Asset retirement obligations	**8,345**	7,705	(d)
Deferred income tax credits	**(14,962)**	(17,654)	(d)
Other cost of removal obligations	**(96,191)**	(90,485)	(d)
Fuel-hedging (realized and unrealized) gains	**(761)**	(4,102)	(j)
Generation screening costs	**37,857**	11,196	(c)
Other liabilities	**(4,894)**	(6,596)	(c)
Overfunded retiree benefit plans	**-**	(53,396)	(b)
Total assets (liabilities), net	**$ 69,143**	$(132,334)	

Note: The recovery and amortization periods for these regulatory assets and (liabilities) are as follows:

(a) For additional information, see Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery."
(b) Recovered and amortized over the average remaining service period which may range up to 14 years. See Note 2 for additional information.
(c) Recorded and recovered as approved by the Mississippi PSC.
(d) Asset retirement and removal liabilities are recorded, deferred income tax assets are recovered and deferred tax liabilities are amortized over the related property lives, which may range up to 50 years. Asset retirement and removal liabilities will be settled and trued up following completion of the related activities.
(e) Recovered through the ad valorem tax adjustment clause over a 12-month period beginning in April of the following year.
(f) Amortized over a four-year period ending 2011.
(g) Recorded as earned by employees and recovered as paid, generally within one year.
(h) Recovered over the remaining life of the original issue/lease or, if refinanced, over the life of the new issue/lease, which may range up to 50 years.
(i) Amortized over a period beginning in 2004 that is not to exceed seven years.
(j) Fuel-hedging assets and liabilities are recorded over the life of the underlying hedged purchase contracts, which generally do not exceed two years. Upon final settlement, costs are recovered through the Energy Cost Management clause (ECM).

In the event that a portion of the Company's operations is no longer subject to the provisions of SFAS No. 71, the Company would be required to write off or reclassify to accumulated other comprehensive income related regulatory assets and liabilities that are not specifically recoverable through regulated rates. In addition, the Company would be required to determine if any impairment to other assets, including plant, exists and write down the assets, if impaired, to their fair values. All regulatory assets and liabilities are to be reflected in rates.

Government Grants

The Company received a grant in October 2006 from the Mississippi Development Authority (MDA) for $276.4 million, primarily for storm damage cost recovery. On June 1, 2007, the Company received a grant payment of $85.2 million from the State of Mississippi related to storm restoration costs incurred and to increase the property damage reserve. In the fourth quarter 2007, the Company received additional grant payments totaling $24.1 million for expenditures incurred to date for construction of a new storm operations center. On May 23, 2008, the Company received grant payments in the amount of $7.3 million and anticipates the receipt of approximately $3.2 million in 2009. The grant proceeds do not represent a future obligation of the Company. The portion of any grants received related to retail storm recovery was applied to the retail regulatory asset that was established as restoration costs were incurred. The portion related to wholesale storm recovery was recorded either as a reduction to operations and maintenance expense or as a reduction to total property, plant, and equipment depending on the restoration work performed and the appropriate allocations of cost of service.

Revenues

Energy and other revenues are recognized as services are rendered. Wholesale capacity revenues from long-term contracts are recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract period. Unbilled revenues related to retail sales are accrued at the end of each fiscal period. The Company's retail and wholesale rates include provisions to adjust billings for fluctuations in fuel costs, fuel hedging, the energy component of purchased power costs, and certain other costs. Retail rates also include provisions to adjust billings for fluctuations in costs for ad valorem taxes and certain qualifying environmental costs. Revenues are adjusted for differences between these actual costs and amounts billed in current regulated rates. Under or over recovered regulatory clause revenues are recorded in the balance sheets and are recovered or returned to customers through adjustments to the billing factors. The Company is required to file with the Mississippi PSC for an adjustment to the fuel cost recovery factor annually.

The Company has a diversified base of customers. For years ended December 31, 2008, and December 31, 2007, no single customer or industry comprises 10% or more of revenues. For all periods presented, uncollectible accounts averaged less than 1% of revenues.

Fuel Costs

Fuel costs are expensed as the fuel is used. Fuel expense generally includes the cost of purchased emission allowances as they are used. Fuel costs also included gains and/or losses from fuel hedging programs as approved by the Mississippi PSC.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. Investment tax credits utilized are deferred and amortized to income over the average life of the related property. Taxes that are collected from customers on behalf of governmental agencies to be remitted to these agencies are presented net on the statements of income.

In accordance with FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

Property, plant, and equipment is stated at original cost less regulatory disallowances and impairments. Original cost includes: materials; labor; minor items of property; appropriate administrative and general costs; payroll-related costs such as taxes, pensions, and other benefits; and the interest capitalized and/or cost of funds used during construction for projects over $10 million.

The Company's property, plant, and equipment consisted of the following at December 31:

	2008	2007
	(in thousands)	
Generation	**$ 919,149**	$ 874,585
Transmission	**436,280**	420,392
Distribution	**720,124**	688,715
General	**159,020**	147,143
Total plant in service	**$2,234,573**	$2,130,835

The cost of replacements of property, exclusive of minor items of property, is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense except for the cost of maintenance of coal cars and a portion of the railway track maintenance costs, which are charged to fuel stock and recovered through the Company's fuel clause.

Depreciation and Amortization

Depreciation of the original cost of plant in service is provided primarily by using composite straight-line rates, which approximated 3.3%, in 2008 and 2007, and 3.2% in 2006. Depreciation studies are conducted periodically to update the composite rates. In March 2006, the Mississippi PSC approved the study filed by the Company in 2005, with new rates effective January 1, 2006. The new depreciation rates did not result in a material change to annual depreciation expense. When property subject to depreciation is retired or otherwise disposed of in the normal course of business, its cost, together with the cost of removal, less salvage, is charged to the accumulated depreciation provision. Minor items of property included in the original cost of the plant are retired when the related property unit is retired. Depreciation expense includes an amount for the expected cost of removal of facilities.

In April 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning January 1, 2007, and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2007, the Company had incurred and deferred the retail portion of $9.5 million of such costs. At December 31, 2008, the Company had a balance of the deferred retail portion of $7.1 million with $2.4 million included in current assets as other regulatory assets and $4.7 million included in long-term other regulatory assets.

In January 2006, the Mississippi PSC issued an accounting order directing the Company to exclude from its calculation of depreciation expense approximately $1.2 million related to capitalized Hurricane Katrina costs since these costs were recovered separately.

In December 2003, the Mississippi PSC issued an interim accounting order directing the Company to expense and record a regulatory liability of $60.3 million while it considered the Company's request to include 266 megawatts of Plant Daniel Units 3 and 4 generating capacity in jurisdictional cost of service. In May 2004, the Mississippi PSC approved the Company's request effective January 1, 2004, and ordered the Company to amortize the regulatory liability previously established to reduce depreciation and amortization expenses over a four year period. The amounts amortized were $5.7 million and $13.0 million in 2007 and 2006, respectively.

Asset Retirement Obligations and Other Costs of Removal

Asset retirement obligations are computed as the present value of the ultimate costs for an asset's future retirement and are recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life. The Company has received accounting guidance from the Mississippi PSC allowing the continued accrual of other future retirement costs for long-lived assets that the Company does not have a legal obligation to retire. Accordingly, the accumulated removal costs for these obligations will continue to be reflected in the balance sheets as a regulatory liability.

The Company has retirement obligations related to various landfill sites, underground storage tanks, and asbestos removal. In connection with the adoption of FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47) the Company also recorded additional asset retirement obligations (and assets) of $9.5 million, primarily related to asbestos. The Company also has identified retirement obligations related to certain transmission and distribution facilities, co-generation facilities, certain wireless communication towers, and certain structures authorized by the United States Army Corps of Engineers. However, liabilities for the removal of these assets have not been recorded because the range of time over which the Company may settle these

obligations is unknown and cannot be reasonably estimated. The Company will continue to recognize in the statements of income allowed removal costs in accordance with its regulatory treatment. Any differences between costs recognized under FASB Statement No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) and FIN 47 and those reflected in rates are recognized as either a regulatory asset or liability, as ordered by the Mississippi PSC, and are reflected in the balance sheets.

Details of the asset retirement obligations included in the balance sheets are as follows:

	2008	2007	2006
	(in millions)		
Balance, beginning of year	**$ 17.3**	$ 15.8	$ 15.4
Liabilities incurred	**-**	0.6	-
Liabilities settled	**(0.1)**	-	(0.1)
Accretion	**1.0**	0.9	0.8
Cash flow revisions	**(0.2)**	-	(0.3)
Balance, end of year	**$ 18.0**	$ 17.3	$ 15.8

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether an impairment has occurred is based on either a specific regulatory disallowance or an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by either the amount of regulatory disallowance or by estimating the fair value of the asset and recording a loss for the amount if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Provision for Property Damage

The Company carries insurance for the cost of certain types of damage to generation plants and general property. However, the Company is self-insured for the cost of storm, fire, and other uninsured casualty damage to its property, including transmission and distribution facilities. As permitted by the Mississippi PSC and the FERC, the Company accrues for the cost of such damage through an annual expense accrual credited to a regulatory liability account. The cost of repairing actual damage resulting from such events that individually exceed $50,000 is charged to the reserve. A 1999 Mississippi PSC order allowed the Company to accrue $1.5 million to $4.6 million to the reserve annually, with a maximum reserve totaling $23 million. In October 2006, in conjunction with the Mississippi PSC Hurricane Katrina-related financing order, the Mississippi PSC ordered the Company to cease all accruals to the retail property damage reserve until a new reserve cap is established. However, in the same financing order, the Mississippi PSC approved the replenishment of the retail property damage reserve with $60 million to be funded with a portion of the proceeds of bonds to be issued by the Mississippi Development Bank on behalf of the State of Mississippi and reported as liabilities by the State of Mississippi. The Company received the $60 million bond proceeds in June 2007. The Company accrued $0.2 million annually in 2008, 2007, and 2006 for the wholesale jurisdiction. The Company made no discretionary retail accruals in 2008 and 2007 as a result of the order. In 2006, the Company accrued $1.0 million for the retail jurisdiction. On January 9, 2009, the Mississippi PSC approved the System Restoration Rider (SRR) stipulation between the Company and the Mississippi Public Utilities Staff. In accordance with the stipulation, every three years the Mississippi PSC, Mississippi Public Utilities Staff and the Company will agree on SRR revenue level(s) for the ensuing period, based on historical data, expected exposure, type and amount of insurance coverage, excluding insurance cost and any other relevant information. The accrual amount and the reserve balance are determined based on the SRR revenue level(s). If a significant change in circumstances occurs then the SRR revenue level can be adjusted more frequently if the Company and the Mississippi Public Utilities Staff or the Mississippi PSC deem the change appropriate. Each year the Company will set rates to collect the approved SRR revenues. The property damage reserve accrual will be the difference between the approved SRR revenues and the SRR revenue requirement, excluding any accrued to the reserve. In addition, SRR allows the Company to set up a regulatory asset, pending review, if the allowable actual retail property damage costs exceed the amount in the retail property damage reserve. See Note 3 under "Retail Regulatory Matters – Storm Damage Cost Recovery" and "Retail Regulatory Matters – System Restoration Rider" for additional information regarding the depletion of these reserves following Hurricane Katrina and the deferral of additional costs, as well as additional rate riders or other cost recovery mechanisms which have and/or may be approved by the Mississippi PSC to recover the deferred costs and accrue reserves.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average cost of transmission, distribution, and generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the average costs of oil, coal, natural gas, and emission allowances. Fuel is charged to inventory when purchased and then expensed as used and recovered by the Company through fuel cost recovery rates approved by the Mississippi PSC. Emission allowances granted by the Environmental Protection Agency (EPA) are included in inventory at zero cost.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in the prices of certain fuel purchases and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (categorized in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 9 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions or are recoverable through the Mississippi PSC approved fuel hedging program as discussed below. This results in the deferral of related gains and losses in other comprehensive income or regulatory assets and liabilities, respectively, as appropriate until the hedged transactions occur. Any ineffectiveness arising from cash flow hedges is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded on a net basis in the statements of income. See Note 6 under "Financial Instruments" for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company has no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2008.

The Mississippi PSC has approved the Company's request to implement an Energy Cost Management clause (ECM) which, among other things, allows the Company to utilize financial instruments to hedge its fuel commitments. Changes in the fair value of these financial instruments are recorded as regulatory assets or liabilities. Amounts paid or received as a result of financial settlement of these instruments are classified as fuel expense and are included in the ECM factor applied to customer billings. The Company's jurisdictional wholesale customers have a similar ECM mechanism, which has been approved by the FERC.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

Other financial instruments for which the carrying amounts did not equal the fair values at December 31 were as follows:

	Carrying Amount	Fair Value
	(in thousands)	
Long-term debt:		
2008	**$407,061**	**$405,957**
2007	277,333	270,897

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2). See Note 9 for all other items recognized at fair value in the financial statements.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income, changes in the fair value of qualifying cash flow hedges, and prior to the adoption of SFAS No.158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS No. 158) the minimum pension liability, less income taxes and reclassifications for amounts included in net income.

Variable Interest Entities

The primary beneficiary of a variable interest entity must consolidate the related assets and liabilities. The Company has established a wholly-owned trust to issue preferred securities. See Note 6 under "Long-Term Debt Payable to Affiliated Trust" for additional information. However, the Company is not considered the primary beneficiary of the trust. Therefore, the investments in this trust are reflected as Other Investments and the related loan from the trust is included in Long-term Debt in the balance sheets. During 2007 the Company redeemed its last remaining series of preferred securities, which totaled $36 million.

2. RETIREMENT BENEFITS

The Company has a defined benefit, trusteed, pension plan covering substantially all employees. The plan is funded in accordance with requirements of the Employee Retirement Income Security Act of 1974, as amended (ERISA). No contributions to the plan are expected for the year ending December 31, 2009. The Company also provides certain defined benefit pension plans for a selected group of management and highly compensated employees. Benefits under these non-qualified pension plans are funded on a cash basis. In addition, the Company provides certain medical care and life insurance benefits for retired employees through other postretirement benefit plans. The Company funds trusts to the extent required by the FERC. For the year ending December 31, 2009, postretirement trust contributions are expected to total approximately $0.1 million.

The measurement date for plan assets and obligations for 2008 was December 31 while the measurement date for prior years was September 30. Pursuant to SFAS No. 158, the Company was required to change the measurement date for its defined benefit postretirement plans from September 30 to December 31 beginning with the year ended December 31, 2008. As permitted, the Company adopted the measurement date provisions of SFAS No. 158 effective January 1, 2008 resulting in an increase in long-term liabilities of approximately $1.6 million and a decrease in prepaid pension costs of approximately $0.1 million.

Pension Plans

The total accumulated benefit obligation for the pension plans was $252 million in 2008 and $240 million in 2007. Changes during the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 in the projected benefit obligations and the fair value of plan assets were as follows:

	2008	2007
	(in thousands)	
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 256,903**	$ 250,543
Service cost	**8,557**	6,934
Interest cost	**19,753**	14,767
Benefits paid	**(14,721)**	(11,529)
Actuarial gain and employee transfers	**(3,613)**	(6,001)
Amendments	**-**	2,189
Balance at end of year	**266,879**	256,903
Change in plan assets		
Fair value of plan assets at beginning of year	**300,866**	267,276
Actual return (loss) on plan assets	**(89,420)**	43,849
Employer contributions	**1,785**	1,270
Benefits paid	**(14,721)**	(11,529)
Fair value of plan assets at end of year	**198,510**	300,866
Funded status at end of year	**(68,369)**	43,963
Fourth quarter contributions	**-**	423
(Accrued liability) prepaid pension asset, net	**$ (68,369)**	$ 44,386

At December 31, 2008, the projected benefit obligations for the qualified and non-qualified pension plans were $244.9 million and $22.0 million, respectively. All pension plan assets are related to the qualified pension plan.

Pension plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code of 1986, as amended (Internal Revenue Code). The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's pension plan assets as of the end of year, along with the targeted mix of assets, is presented below:

	Target	2008	2007
Domestic equity	36%	**34%**	38%
International equity	24	**23**	24
Fixed income	15	**14**	15
Real estate	15	**19**	16
Private equity	10	**10**	7
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's pension plans consist of:

	2008	2007
	(in thousands)	
Prepaid pension costs	$ -	$ 66,099
Other regulatory assets	66,602	11,114
Current liabilities, other	(1,498)	(1,393)
Other regulatory liabilities	-	(53,396)
Employee benefit obligations	(66,871)	(20,320)

Presented below are the amounts included in regulatory assets and regulatory liabilities at December 31, 2008 and 2007 related to the defined benefit pension plans that had not yet been recognized in net periodic pension cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	Net(Gain)Loss
Balance at December 31, 2008:	*(in thousands)*	
Regulatory asset	$ 10,800	$ 55,802
Regulatory liabilities	-	-
Total	$ 10,800	$ 55,802
Balance at December 31, 2007:		
Regulatory asset	$ 2,674	$ 8,440
Regulatory liabilities	10,212	(63,608)
Total	$ 12,886	$(55,168)
Estimated amortization in net periodic pension cost in 2009:		
Regulatory asset	$ 1,578	$ 539
Regulatory liabilities	-	-
Total	$ 1,578	$ 539

The changes in the balances of regulatory assets and regulatory liabilities related to the defined benefit pension plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007 are presented in the following table:

	Regulatory Assets	Regulatory Liabilities
	(in thousands)	
Balance at December 31, 2006	$ 9,707	$ (21,319)
Net (gain) loss	166	(30,800)
Change in prior service costs	2,189	-
Reclassification adjustments:		
Amortization of prior service costs	(314)	(1,277)
Amortization of net gain	(634)	-
Total reclassification adjustments	(948)	(1,277)
Total change	1,407	(32,077)
Balance at December 31, 2007	$ 11,114	$ (53,396)
Net (gain) loss	56,721	54,849
Change in prior service costs	-	-
Reclassification adjustments:		
Amortization of prior service costs	(489)	(1,596)
Amortization of net gain	(744)	143
Total reclassification adjustments	(1,233)	(1,453)
Total change	55,488	53,396
Balance at December 31, 2008	$ 66,602	$ -

Components of net periodic pension cost (income) were as follows:

	2008	2007	2006
		(in thousands)	
Service cost	**$ 6,846**	$ 6,934	$ 7,207
Interest cost	**15,802**	14,767	13,727
Expected return on plan assets	**(20,611)**	(19,099)	(18,107)
Recognized net (gain) loss	**481**	634	773
Net amortization	**1,668**	1,591	1,013
Net periodic pension cost	**$ 4,186**	$ 4,827	$ 4,613

Net periodic pension cost (income) is the sum of service cost, interest cost, and other costs netted against the expected return on plan assets. The expected return on plan assets is determined by multiplying the expected rate of return on plan assets and the market-related value of plan assets. In determining the market-related value of plan assets, the Company has elected to amortize changes in the market value of all plan assets over five years rather than recognize the changes immediately. As a result, the accounting value of plan assets that is used to calculate the expected return on plan assets differs from the current fair value of the plan assets.

Future benefit payments reflect expected future service and are estimated based on assumptions used to measure the projected benefit obligation for the pension plans. At December 31, 2008, estimated benefit payments were as follows:

	Benefit Payments
	(in thousands)
2009	$12,947
2010	13,332
2011	13,971
2012	14,916
2013	15,726
2014 to 2018	95,981

Other Postretirement Benefits

Changes during the 15-month period ended December 31, 2008 and the year ended September 30, 2007 in the accumulated postretirement benefit obligations (APBO) and in the fair value of plan assets were as follows:

	2008	2007
		(in thousands)
Change in benefit obligation		
Benefit obligation at beginning of year	**$ 84,495**	$ 89,673
Service cost	**1,745**	1,372
Interest cost	**6,498**	5,254
Benefits paid	**(5,333)**	(3,754)
Actuarial (gain) loss	**(3,275)**	(8,388)
Retiree drug subsidy	**603**	338
Balance at end of year	**84,733**	84,495
Change in plan assets		
Fair value of plan assets at beginning of year	**25,593**	23,689
Actual return (loss) on plan assets	**(5,653)**	3,470
Employer contributions	**3,414**	1,851
Benefits paid	**(4,731)**	(3,417)
Fair value of plan assets at end of year	**18,623**	25,593
Funded status at end of year	**(66,110)**	(58,902)
Fourth quarter contributions	**-**	906
Accrued liability	**$(66,110)**	$(57,996)

Other postretirement benefit plan assets are managed and invested in accordance with all applicable requirements, including ERISA and the Internal Revenue Code. The Company's investment policy covers a diversified mix of assets, including equity and fixed income securities, real estate, and private equity. Derivative instruments are used primarily as hedging tools but may also be used to gain efficient exposure to the various asset classes. The Company primarily minimizes the risk of large losses through diversification but also monitors and manages other aspects of risk. The actual composition of the Company's other postretirement benefit plan assets as of the end of year, along with the targeted mix of assets, is presented below:

	Target	**2008**	2007
Domestic equity	27%	**26%**	31%
International equity	18	**18**	20
Fixed income	36	**35**	30
Real estate	11	**14**	13
Private equity	8	**7**	6
Total	100%	**100%**	100%

Amounts recognized in the balance sheets related to the Company's other postretirement benefit plans consist of the following:

	2008	2007
	(in thousands)	
Regulatory assets	**$ 20,491**	$ 17,217
Employee benefit obligations	**(66,110)**	(57,996)

Presented below are the amounts included in regulatory assets at December 31, 2008 and 2007, related to the other postretirement benefit plans that had not yet been recognized in net periodic postretirement benefit cost along with the estimated amortization of such amounts for 2009.

	Prior Service Cost	**Net(Gain) Loss**	**Transition Obligation**
		(in thousands)	
Balance at December 31, 2008:			
Regulatory assets	**$1,054**	**$18,020**	**$1,417**
Balance at December 31, 2007:			
Regulatory assets	$1,187	$14,180	$1,850
Estimated amortization as net periodic postretirement benefit cost in 2009:			
Regulatory assets	$106	$540	$346

The change in the balance of regulatory assets related to the postretirement benefit plans for the 15-month period ended December 31, 2008 and the 12-month period ended September 30, 2007, is presented in the following table:

	Regulatory Assets
	(in thousands)
Beginning balance	$ 29,107
Net (gain) loss	(10,256)
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	(346)
Amortization of prior service costs	(106)
Amortization of net gain	(1,182)
Total reclassification adjustments	(1,634)
Total change	(11,890)
Balance at December 31, 2007	$ 17,217
Net (gain) loss	4,607
Change in prior service costs	-
Reclassification adjustments:	
Amortization of transition obligation	(433)
Amortization of prior service costs	(132)
Amortization of net gain	(768)
Total reclassification adjustments	(1,333)
Total change	3,274
Balance at December 31, 2008	$ 20,491

Components of the other postretirement benefit plans' net periodic cost were as follows:

	2008	2007	2006
		(in thousands)	
Service cost	**$ 1,396**	$ 1,372	$ 1,520
Interest cost	**5,199**	5,254	4,654
Expected return on plan assets	**(1,805)**	(1,673)	(1,642)
Net amortization	**1,066**	1,633	1,702
Net postretirement cost	**$ 5,856**	$ 6,586	$ 6,234

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (Medicare Act) provides a 28% prescription drug subsidy for Medicare eligible retirees. The effect of the subsidy reduced the Company's expenses for the years ended December 31, 2008, 2007, and 2006 by approximately $1.8 million, $1.8 million, and $2.0 million, respectively.

Future benefit payments, including prescription drug benefits, reflect expected future service and are estimated based on assumptions used to measure the APBO for the postretirement plans. Estimated benefit payments are reduced by drug subsidy receipts expected as a result of the Medicare Act as follows:

	Benefit Payments	Subsidy Receipts	Total
		(in thousands)	
2009	$ 4,629	$ (479)	$4,150
2010	5,122	(541)	4,581
2011	5,540	(616)	4,924
2012	5,917	(702)	5,215
2013	6,343	(779)	5,564
2014 to 2018	36,484	(5,305)	31,179

Actuarial Assumptions

The weighted average rates assumed in the actuarial calculations used to determine both the benefit obligations as of the measurement date and the net periodic costs for the pension and other postretirement benefit plans for the following year are presented below. Net periodic benefit costs were calculated in 2005 for the 2006 plan year using a discount rate of 5.50%.

	2008	2007	2006
Discount	**6.75%**	6.30%	6.00%
Annual salary increase	**3.75**	3.75	3.50
Long-term return on plan assets	**8.50**	8.50	8.50

The Company determined the long-term rate of return based on historical asset class returns and current market conditions, taking into account the diversification benefits of investing in multiple asset classes.

An additional assumption used in measuring the APBO was a weighted average medical care cost trend rate of 9.15% for 2009, decreasing gradually to 5.50% through the year 2015 and remaining at that level thereafter. An annual increase or decrease in the assumed medical care cost trend rate of 1% would affect the APBO and the service and interest cost components at December 31, 2008 as follows:

	1 Percent Increase	**1 Percent Decrease**
	(in thousands)	
Benefit obligation	$5,740	$5,826
Service and interest costs	360	307

Employee Savings Plan

The Company also sponsors a 401(k) defined contribution plan covering substantially all employees. The Company provides an 85 percent matching contribution up to 6 percent of an employee's base salary. Prior to November 2006, the Company matched employee contributions at a rate of 75 percent up to 6 percent of the employee's base salary. Total matching contributions made to the plan for 2008, 2007, and 2006 were $3.7 million, $3.5 million, and $3.0 million, respectively.

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

Environmental Matters

New Source Review Actions

In November 1999, the EPA brought a civil action in the U.S. District Court for the Northern District of Georgia against certain Southern Company subsidiaries, including Alabama Power and Georgia Power, alleging that these subsidiaries had violated the New Source Review (NSR) provisions of the Clean Air Act and related state laws at certain coal-fired generating facilities. After Alabama Power was dismissed from the original action for jurisdictional reasons, the EPA filed a separate action in January 2001 against Alabama Power in the U.S. District Court for the Northern District of Alabama. In these lawsuits, the EPA alleged that NSR violations occurred at eight coal-fired generating facilities operated by Alabama Power and Georgia Power, including one co-owned by the Company. The civil actions request penalties and injunctive relief, including an order requiring installation of the best available

control technology at the affected units. The action against Georgia Power has been administratively closed since the spring of 2001, and the case has not been reopened.

In June 2006, the U.S. District Court for the Northern District of Alabama entered a consent decree between Alabama Power and the EPA, resolving a portion of the Alabama Power lawsuit relating to the alleged NSR violations at Plant Miller. The consent decree required Alabama Power to pay $100,000 to resolve the government's claim for a civil penalty and to donate $4.9 million of sulfur dioxide emission allowances to a nonprofit charitable organization. It also formalized specific emissions reductions to be accomplished by Alabama Power, consistent with other Clean Air Act programs that require emissions reductions. In August 2006, the district court in Alabama granted Alabama Power's motion for summary judgment and entered final judgment in favor of Alabama Power on the EPA's claims related to all of the remaining plants: Plants Barry, Gaston, Gorgas, and Greene County.

The plaintiffs appealed the district court's decision to the U.S. Court of Appeals for the Eleventh Circuit, where the appeal was stayed, pending the U.S. Supreme Court's decision in a similar case against Duke Energy. The Supreme Court issued its decision in the Duke Energy case in April 2007, and in December 2007, the Eleventh Circuit vacated the district court's decision in the Alabama Power case and remanded the case back to the district court for consideration of the legal issues in light of the Supreme Court's decision in the Duke Energy case. On July 24, 2008, the U.S. District Court for the Northern District of Alabama granted partial summary judgment in favor of Alabama Power regarding the proper legal test for determining whether projects are routine maintenance, repair, and replacement and therefore are excluded from NSR permitting. The decision did not resolve the case, and the ultimate outcome of these matters cannot be determined at this time.

The Company believes that it complied with applicable laws and the EPA regulations and interpretations in effect at the time the work in question took place. The Clean Air Act authorizes maximum civil penalties of $25,000 to $37,500 per day, per violation at each generating unit, depending on the date of the alleged violation. An adverse outcome in either of these cases could require substantial capital expenditures or affect the timing of currently budgeted capital expenditures that cannot be determined at this time and could possibly require payment of substantial penalties. Such expenditures could affect future results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

Carbon Dioxide Litigation

New York Case

In July 2004, three environmental groups and attorneys general from eight states, each outside of Southern Company's service territory, and the corporation counsel for New York City filed complaints in the U.S. District Court for the Southern District of New York against Southern Company and four other electric power companies. The complaints allege that the companies' emissions of carbon dioxide, a greenhouse gas, contribute to global warming, which the plaintiffs assert is a public nuisance. Under common law public and private nuisance theories, the plaintiffs seek a judicial order (1) holding each defendant jointly and severally liable for creating, contributing to, and/or maintaining global warming and (2) requiring each of the defendants to cap its emissions of carbon dioxide and then reduce those emissions by a specified percentage each year for at least a decade. The plaintiffs have not, however, requested that damages be awarded in connection with their claims. Southern Company believes these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. In September 2005, the U.S. District Court for the Southern District of New York granted Southern Company's and the other defendants' motions to dismiss these cases. The plaintiffs filed an appeal to the U.S. Court of Appeals for the Second Circuit in October 2005, but no decision has been issued. The ultimate outcome of these matters cannot be determined at this time.

Kivalina Case

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

Environmental Remediation

The Company must comply with other environmental laws and regulations that cover the handling and disposal of waste and releases of hazardous substances. Under these various laws and regulations, the Company may also incur substantial costs to clean up properties. The Company has authority from the Mississippi PSC to recover approved environmental compliance costs through regulatory mechanisms.

In 2003, the Texas Commission on Environmental Quality (TCEQ) designated the Company as a potentially responsible party at a site in Texas. The site was owned by an electric transformer company that handled the Company's transformers as well as those of many other entities. The site owner is now in bankruptcy and the State of Texas has entered into an agreement with the Company and several other utilities to investigate and remediate the site. Amounts expensed during 2006, 2007, and 2008 related to this work were not material. Hundreds of entities have received notices from the TCEQ requesting their participation in the anticipated site remediation. The final impact of this matter on the Company will depend upon further environmental assessment and the ultimate number of potentially responsible parties. The remediation expenses incurred by the Company are expected to be recovered through the ECO Plan.

The final outcome of these matters cannot now be determined. However, based on the currently known conditions at these sites and the nature and extent of activities relating to these sites, the Company does not believe that additional liabilities, if any, at these sites would be material to the financial statements.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $8.4 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed the FERC's prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response

addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Intercompany Interchange Contract

The Company's generation fleet is operated under the Intercompany Interchange Contract (IIC), as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the traditional operating companies (including the Company), Southern Power, and Southern Company Services, Inc., as agent, under the terms of which the power pool of Southern Company is operated, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining Southern Power as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of Southern Power, the FERC authorized Southern Power's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms and Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. Implementation of the plan did not have a material impact on the Company's financial statements. In November 2007, Southern Company notified the FERC that the plan had been implemented. On December 12, 2008, the FERC division of audits issued for public comment its final audit report pertaining to compliance implementation and related matters. No comments challenging the audit report's findings were submitted. A decision is now pending from the FERC.

Wholesale Rate Filing

On August 29, 2008, Mississippi Power filed with the FERC a request for revised wholesale electric tariff and rates. Prior to making this filing, Mississippi Power reached a settlement with all of its customers who take service under the tariff. This settlement agreement was filed with the FERC as part of the request. The settlement agreement provided for an increase in annual base wholesale revenues in the amount of $5.8 million, effective January 1, 2009. In addition, the settlement allows Mississippi Power to increase its annual accrual for the wholesale portion of property damage to $303,000 per year, to defer any property damage costs prudently incurred in excess of the wholesale property damage reserve balance, and to defer the wholesale portion of the generation screening and evaluation costs associated with the integrated coal gasification combined cycle (IGCC) project to be located in Kemper County Mississippi. The settlement agreement also provided that Mississippi Power will not seek a change in wholesale full-requirements rates before November 1, 2010, except for changes associated with the fuel adjustment clause and the energy cost management clause, changes associated with property damages that exceed the amount in the wholesale property damage reserve, and changes associated with costs and expenses associated with environmental requirements affecting fossil fuel generating facilities. On October 24, 2008, Mississippi Power received notice that the FERC had accepted the filing effective November 1, 2008, and the revised monthly charges were applied beginning January 1, 2009. As result of the order, the Company reclassified $9.3 million of previously expensed generation screening and evaluation costs to a regulatory asset. See "Integrated Coal Gasification Combined Cycle" herein for additional information.

Right of Way Litigation

Southern Company and certain of its subsidiaries, including the Company, Gulf Power, and Southern Telecom, Inc., (a subsidiary of SouthernLINC Wireless), have been named as defendants in numerous lawsuits brought by landowners since 2001. The plaintiffs' lawsuits claim that defendants may not use, or sublease to third parties, some or all of the fiber optic communications lines on the rights of way that cross the plaintiffs' properties and that such actions exceed the easements or other property rights held by defendants. The plaintiffs assert claims for, among other things, trespass and unjust enrichment and seek compensatory and punitive damages and injunctive relief. Management of the Company believes that it has complied with applicable laws and that the plaintiffs' claims are without merit.

To date, the Company has entered into agreements with plaintiffs in approximately 95% of the actions pending against the Company to clarify the Company's easement rights in the State of Mississippi. These agreements have been approved by the Circuit Courts of Harrison County and Jasper County, Mississippi (First Judicial Circuit), and dismissals of the related cases are in progress. These agreements have not had any material impact on the Company's financial statements.

In addition, in late 2001, certain subsidiaries of Southern Company, including Alabama Power, Georgia Power, Gulf Power, the Company, and Southern Telecom, Inc., (a subsidiary of SouthernLINC Wireless), were named as defendants in a lawsuit brought in Troup County, Georgia, Superior Court by Interstate Fiber Network, a subsidiary of telecommunications company ITC DeltaCom, Inc. that uses certain of the defendants' rights of way. This lawsuit alleges, among other things, that the defendants are contractually obligated to indemnify, defend, and hold harmless the telecommunications company from any liability that may be assessed against it in pending and future right of way litigation. The Company believes that the plaintiff's claims are without merit. In the fall of 2004, the trial court stayed the case until resolution of the underlying landowner litigation discussed above. In January 2005, the Georgia Court of Appeals dismissed the telecommunications company's appeal of the trial court's order for lack of jurisdiction. An adverse outcome in this matter, combined with an adverse outcome against the telecommunications company in one or more of the right of way lawsuits, could result in substantial judgments; however, the final outcome of these matters cannot now be determined.

Retail Regulatory Matters

Performance Evaluation Plan

The Company's retail base rates are set under Performance Evaluation Plan (PEP), a rate plan approved by the Mississippi PSC. PEP was designed with the objective that PEP would reduce the impact of rate changes on the customer and provide incentives for the Company to keep customer prices low and customer satisfaction and reliability high. PEP is a mechanism for rate adjustments based on three indicators: price, customer satisfaction, and service reliability.

In May 2004, the Mississippi PSC approved the Company's request to modify certain portions of its PEP and to reclassify, to jurisdictional cost of service the 266 megawatts of Plant Daniel Units 3 and 4 capacity, effective January 1, 2004. The Mississippi PSC authorized the Company to include the related costs and revenue credits in jurisdictional rate base, cost of service, and revenue requirement calculations for purposes of retail rate recovery. The Company amortized the regulatory liability pursuant to the Mississippi PSC's order, over a four-year period, resulting in increases to earnings in each of those years. The amounts amortized were $5.7 million and $13.0 million in 2007 and 2006, respectively.

In addition, in May 2004, the Mississippi PSC approved the Company's requested changes to PEP, including the use of a forward-looking test year, with appropriate oversight; annual, rather than semi-annual, filings; and certain changes to the performance indicator mechanisms. Rate changes will be limited to four percent of retail revenues annually under the revised PEP. PEP will remain in effect until the Mississippi PSC modifies, suspends, or terminates the plan. In the May 2004 order, the Mississippi PSC ordered that the Mississippi Public Utilities Staff and the Company review the operations of the PEP in 2007. By mutual agreement, this review was deferred until 2008 and is currently ongoing. The outcome of this review is cannot now be determined.

In April 2007, the Mississippi PSC issued an order allowing the Company to defer certain reliability related maintenance costs beginning January 1, 2007, and recover them evenly over a four-year period beginning January 1, 2008. These costs related to maintenance that was needed as follow-up to emergency repairs that were made subsequent to Hurricane Katrina. At December 31, 2007, the Company had incurred and deferred the retail portion of $9.5 million of such costs. At December 31, 2008, the Company had a balance of the deferred retail portion of $7.1 million with $2.4 million included in current assets as other regulatory assets and $4.7 million included in long-term other regulatory assets.

In September 2007, the Mississippi Public Utilities Staff and the Company entered into a stipulation that included adjustments to expenses which resulted in a one-time credit to retail customers of approximately $1.1 million. In November 2007, the Mississippi PSC issued an order requiring the Company to refund this amount to its retail customers no later than December 2007. This amount was totally refunded as a credit to customer bills by December 31, 2007.

In December 2007, the Company submitted its annual PEP filing for 2008, which resulted in a rate increase of 1.983% or $15.5 million annually, effective January 2008. In December 2006, the Company submitted its annual PEP filing for 2007, which resulted in no rate change.

In December 2007, the Company received an order from the Mississippi PSC requiring it to defer $1.4 million associated with the retail portion of certain tax credits and adjustments related to permanent differences pertaining to its 2006 income tax returns filed in September 2007. These tax differences were recorded in a regulatory liability included in the current portion of other regulatory liabilities and were amortized ratably over the twelve month period beginning January 2008. The amortization of $1.4 million is included in Income Taxes on the Statement of Income.

On March 14, 2008, the Company submitted its annual PEP lookback filing for 2007, which recommended no surcharge or refund. At the conclusion of the Mississippi Public Utilities Staff's review of the PEP lookback filing for 2007, the Company and Mississippi Public Utilities Staff jointly submitted a stipulation to the Commission which recommended no surcharge or refund.

The Mississippi Public Utilities Staff, pursuant to the Mississippi PSC's 2004 order approving the current PEP plan, is reviewing PEP to determine if any modifications should be made to the plan. Concurrent with this review, the annual PEP evaluation filing for 2009 was delayed by order of the Mississippi PSC and was scheduled to be filed on or before March 9, 2009. On February 23, 2009, however, the Company requested that the Mississippi PSC issue an order suspending the 2009 PEP evaluation filing to continue the scheduled review of the plan. The Company does not anticipate that suspending the PEP filing for 2009 will have a material impact on 2009 earnings. The Company anticipates that, as a result of the required review, changes to the plan will be made. Annual evaluations would resume for 2010 under a revised PEP plan. The final outcome cannot be determined at this time.

System Restoration Rider

In September 2006, the Company filed with the Mississippi PSC a request to implement a System Restoration Rider (SRR), to increase the Company's cap on the property damage reserve and to authorize the calculation of an annual property damage accrual based on a formula. The purpose of the SRR is to provide for recovery of costs associated with property damage (including certain property insurance and the costs of self insurance) and to facilitate the Mississippi PSC's review of these costs. The Company would be required to make annual SRR filings to determine the revenue requirement associated with the property damage. The Company recorded a regulatory liability in the amount of approximately $2.4 million in 2006 and $0.6 million in 2007 for the estimated amount due to retail customers that would be passed through SRR. In November 2007, the Company along with the Mississippi Public Utilities Staff has agreed and stipulated to a revised SRR calculation method that would no longer require the Mississippi PSC to set a cap on the property damage reserve or to authorize the calculation of an annual property damage accrual. Under the revised SRR calculation method, the Mississippi PSC would periodically agree on SRR revenue levels that would be developed based on historical data, expected exposure, type and amount of insurance coverage excluding insurance costs, and other relevant information.

On January 9, 2009, the Mississippi PSC issued an order accepting the stipulation and the revised SRR calculation method. The applicable SRR rate level will be adjusted every three years, unless a significant change in circumstances occurs such that the Company and the Staff or the Mississippi PSC deems that a more frequent change would be appropriate. The Company will submit annual filings setting forth SRR-related revenues, expenses and investment for the projected filing period, as well as the true-up for the prior period. As a result the December 2008 retail regulatory liability of $6.8 million was reclassified to the Property Damage Reserve. On February 2, 2009, the Company submitted its 2009 SRR rate filing with the Mississippi PSC, which proposed that the 2009 SRR rate level remain at zero and the Company be allowed to accrue approximately $4.0 million to the property damage reserve in 2009. The final outcome of this matter cannot now be determined.

Environmental Compliance Overview Plan

On February 3, 2009, the Company submitted its 2009 ECO Plan Notice which proposes an increase of 19 cents per 1,000 KWH for residential customers. The final outcome of this matter cannot now be determined. On February 1, 2008, the Company filed with the Mississippi PSC its annual ECO Plan evaluation for 2008. After the filing of the ECO Plan evaluation on February 1, 2008, the regulations addressing mercury emissions were altered by a decision issued by the U.S. Court of Appeals for the District of Columbia Circuit on February 8, 2008. On April 7, 2008, Mississippi Power filed with the Mississippi PSC a supplemental ECO Plan evaluation in which the projects included in the ECO Plan evaluation on February 1, 2008 being undertaken primarily for mercury control were removed. In this supplemental ECO Plan filing, Mississippi Power requested a 15 cent per 1,000 KWH decrease for retail residential customers. The Mississippi PSC approved the supplemental ECO Plan evaluation on June 11, 2008, with the new rates effective in June 2008. In April 2007, the Mississippi PSC approved the Company's 2007 ECO Plan, which included an 86 cents per 1,000 KWH increase for retail residential customers. This increase represented an addition of approximately $7.5 million in annual revenues for the Company. The new rates were effective in April 2007.

Fuel Cost Recovery

The Company establishes, annually, a retail fuel cost recovery factor that is approved by the Mississippi PSC. Over the past several years, the Company has continued to experience higher than expected fuel costs for coal and natural gas. The Company is required to file for an adjustment to the retail fuel cost recovery factor annually; such filing occurred in November 2008. On December 29, 2008, the Mississippi PSC held a hearing on the Company's proposed increase in its fuel cost recovery factor. On February 11, 2009, the hearing examiner submitted a formal recommendation to the Mississippi PSC for approval of the factor as filed, with recovery proposed for the remaining calendar months of 2009. Any over or under recovery of fuel costs for 2009 would be addressed in the Company's 2010 fuel cost recovery filing. The recommendation is under review by the Mississippi PSC at this time; therefore, the final outcome of this matter cannot now be determined. The proposed retail fuel cost recovery factor will result in an annual increase in an amount equal to 12.2% of total 2008 retail revenue. At December 31, 2008, the amount of under recovered retail fuel costs included in the balance sheet was $36.0 million compared to $24.5 million at December 31, 2007. The Company also has a wholesale Municipal and Rural Associations (MRA) and Market Base (MB) fuel cost recovery factor. Effective January 1, 2009, the wholesale MRA fuel rate increased resulting in an annual increase in an amount equal to 13.9% of total 2008 MRA revenue. Effective February 1, 2009, the wholesale MB fuel rate increased resulting in an annual increase in an amount equal to 16.7% of total 2008 MB revenue. At December 31, 2008, the amount of under recovered wholesale MRA and MB fuel costs included in the balance sheets was $15.4 million and $3.7 million compared to $13.7 million and $2.3 million, respectively, at December 31, 2007. The Company's operating revenues are adjusted for differences in actual recoverable fuel cost and amounts billed in accordance with the currently approved cost recovery rate. Accordingly, this increase to the billing factor will have no significant effect on the Company's revenues or net income, but will increase annual cash flow.

On October 7, 2008, the Mississippi PSC opened a docket to investigate and review interest and carrying charges under the fuel adjustment clause for utilities within the State of Mississippi including Mississippi Power. A hearing was held November 6, 2008, to hear testimony regarding the method of calculating carrying charges on over and under recoveries of fuel-related costs. The ultimate outcome of this matter cannot now be determined.

Storm Damage Cost Recovery

In August 2005, Hurricane Katrina hit the Gulf Coast of the United States and caused significant damage within the Company's service area. The estimated total storm restoration costs relating to Hurricane Katrina through December 31, 2007 of $302.4 million, which was net of expected insurance proceeds of approximately $77 million, without offset for the property damage reserve of $3.0 million, was affirmed by the Mississippi PSC in June 2006, and the Company was ordered to establish a regulatory asset for the retail portion. The Mississippi PSC issued an order directing the Company to file an application with the MDA for a CDBG. In October 2006, the Company received from the MDA a CDBG in the amount of $276.4 million, which was allocated to both the retail and wholesale jurisdictions. In the same month, the Mississippi PSC issued a financing order that authorized the issuance of system restoration bonds for the remaining $25.2 million of the retail portion of storm recovery costs not covered by the CDBG. These funds were received in June 2007. The Company affirmed the $302.4 million total storm costs incurred as of December 31, 2007. The Company plans to file with the Mississippi PSC its final accounting of the restoration cost relating to Hurricane Katrina and the storm operations center by the end of the first quarter 2009, at which time the final net retail receivable of approximately $3.2 million is expected to be recovered.

Integrated Coal Gasification Combined Cycle

On January 16, 2009, the Company filed for a Certificate of Public Convenience and Necessity with the Mississippi PSC to allow construction of a new electric generating plant located in Kemper County, Mississippi. The plant would utilize an advanced coal IGCC with an output capacity of 582 megawatts. The Kemper IGCC will use locally mined lignite (an abundant, lower heating value coal) from a proposed mine adjacent to the plant as fuel. This certificate, if approved by the Mississippi PSC, would authorize the Company to acquire, construct and operate the Kemper IGCC and related facilities. The Kemper IGCC, subject to federal and state environmental reviews and certain regulatory approvals, is expected to begin commercial operation in November 2013. As part of its filing, the Company has requested certain rate recovery treatment in accordance with the base load construction legislation.

The Company filed an application in June 2006 with the U.S. Department of Energy (DOE) for certain tax credits available to projects using clean coal technologies under the Energy Policy Act of 2005. The DOE subsequently certified the Kemper IGCC, and in November 2006 the IRS allocated Internal Revenue Code Section 48A tax credits of $133 million to the Company. The utilization of these credits is dependent upon meeting the certification requirements for the Kemper IGCC, including an in-service date no later than November 2013. The Company has secured all environmental reviews and permits necessary to commence construction of the

Kemper IGCC and has entered into a binding contract for the steam turbine generator, completing two milestone requirements for the Section 48A credits.

On February 14, 2008, the Company also requested that the DOE transfer the remaining funds previously granted to a cancelled Southern Company project that would have been located in Orlando, Florida. On December 12, 2008, an agreement was reached to assign the remaining funds to the Kemper IGCC. The estimated construction cost of the Kemper IGCC is approximately $2.2 billion, which is net of $220 million related to funding to be received from the DOE related to project construction. The remaining DOE funding of $50 million is projected to be used for demonstration over the first few years of operation.

Beginning in December 2006, the Mississippi PSC has approved the Company's requested accounting treatment to defer the costs associated with the Company's generation resource planning, evaluation, and screening activities as a regulatory asset. On December 22, 2008, the Company requested an amendment to its original order that would allow these costs to continue to be charged to and remain in a regulatory asset until January 1, 2010. In its application, the Company reported that it anticipated spending approximately $61 million by or before May 31, 2009. At December 31, 2008, the Company had spent $42.3 million of the $61 million, of which $3.7 million related to land purchases capitalized. Of the remaining amount, $0.8 million was expensed and $37.8 million was deferred in other regulatory assets.

The final outcome of this matter cannot now be determined.

4. JOINT OWNERSHIP AGREEMENTS

The Company and Alabama Power own, as tenants in common, Units 1 and 2, (total capacity of 500 megawatts) at Greene County Steam Plant, which is located in Alabama and operated by Alabama Power. Additionally, the Company and Gulf Power, own as tenants in common, Units 1 and 2, (total capacity of 1,000 megawatts) at Plant Daniel, which is located in Mississippi and operated by the Company.

At December 31, 2008, the Company's percentage ownership and investment in these jointly owned facilities were as follows:

Generating Plant	Percent Ownership	Gross Investment	Accumulated Depreciation
		(in thousands)	
Greene County Units 1 and 2	40%	$ 83,721	$ 43,295
Daniel Units 1 and 2	50%	$273,134	$135,905

The Company's proportionate share of plant operating expenses is included in the statements of income and the Company is responsible for its own financing.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined income tax returns for the State of Alabama and the State of Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with Internal Revenue Service regulations, each company is jointly and severally liable for the tax liability.

Current and Deferred Income Taxes

Details of the income tax provisions were as follows:

	2008	2007	2006
		(in thousands)	
Federal –			
Current	**$ 20,834**	$ 79,127	$79,332
Deferred	**22,054**	(34,524)	(36,889)
	42,888	44,603	42,443
State –			
Current	**2,675**	9,274	16,300
Deferred	**2,786**	(2,047)	(10,646)
	5,461	7,227	5,654
Total	**$ 48,349**	$ 51,830	$ 48,097

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2008	2007
		(in thousands)
Deferred tax liabilities –		
Accelerated depreciation	**$261,091**	$230,379
Basis differences	**29,089**	39,944
Fuel clause under recovered	**25,534**	10,570
Regulatory assets associated with asset retirement obligations	**7,100**	6,790
Regulatory assets associated with employee benefit obligations	**37,003**	15,139
Other	**20,915**	46,442
Total	**380,732**	349,264
Deferred tax assets –		
Federal effect of state deferred taxes	**10,724**	9,535
Other property basis differences	**7,338**	8,030
Pension and other benefits	**56,024**	33,622
Property insurance	**21,997**	26,005
Unbilled fuel	**10,400**	10,045
Other comprehensive loss	**0**	(371)
Asset retirement obligations	**7,100**	6,790
Regulatory liabilities associated with employee benefit obligations	**0**	20,433
Other	**36,617**	29,785
Total	**150,200**	143,874
Total deferred tax liabilities, net	**230,532**	205,390
Portion included in (accrued) prepaid income taxes, net	**(8,208)**	1,428
Accumulated deferred income taxes	**$222,324**	$206,818

At December 31, 2008, the tax-related regulatory assets and liabilities were $8.9 million and $15.0 million, respectively. These assets are attributable to tax benefits flowed through to customers in prior years and to taxes applicable to capitalized interest. These liabilities are attributable to deferred taxes previously recognized at rates higher than the current enacted tax law and to unamortized investment tax credits.

In accordance with regulatory requirements, deferred investment tax credits are amortized over the lives of the related property with such amortization normally applied as a credit to reduce depreciation in the statements of income. Credits amortized in this manner amounted to $1.2 million, $1.1 million, and $1.1 million for 2008, 2007, and 2006, respectively. At December 31, 2008, all investment tax credits available to reduce federal income taxes payable had been utilized.

Effective Tax Rate

The provision for income taxes differs from the amount of income taxes determined by applying the applicable U.S. federal statutory rate to earnings before income taxes and preferred dividends as a result of the following:

	2008	2007	2006
Federal statutory rate	**35.0%**	35.0%	35.0%
State income tax, net of federal deduction	**2.6**	3.0	3.0
Non-deductible book depreciation	**0.3**	0.3	0.3
Production activities deduction	**(0.4)**	(0.5)	(0.1)
Medicare subsidy	**(0.5)**	(0.5)	(0.5)
Amortization of permanent tax items[(a)]	**(0.7)**	-	-
Other	**(0.8)**	0.4	(1.4)
Effective income tax rate	**35.5%**	37.7%	36.3%

[(a)]Amortization of Regulatory Liability Tax Credits. See Note 3 under "Retail Regulatory Matters - Performance Evaluation Plan."

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the IRC Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. This increase from 3% in 2006 to 6% in 2007 was one of several factors that increased the Company's 2007 deduction by $0.3 million over the 2006 deduction. The resulting additional tax benefit was over $0.1 million. The IRS has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction for all previous years to conform to the agreement which resulted in a decrease in the 2008 deduction when compared to the 2007 deduction. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements.

Unrecognized Tax Benefits

FIN 48 requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties. For 2008, the total amount of unrecognized tax benefits increased $0.8 million, resulting in a balance of $1.8 million as of December 31, 2008. Changes during the year in unrecognized tax benefits were as follows:

	2008	**2007**
	(in thousands)	
Unrecognized tax benefits at beginning of year	**$ 935**	**$ 656**
Tax positions from current periods	**653**	**177**
Tax positions from prior periods	**265**	**102**
Reductions due to settlements	**(81)**	**-**
Reductions due to expired statute of limitations	**-**	**-**
Balance at end of year	**$ 1,772**	**$ 935**

The reduction due to settlements relates to the agreement with the IRS regarding the production activities deduction methodology.

Impact on the Company's effective tax rate, if recognized, is as follows:

	2008	2007	Change
		(in thousands)	
Tax positions impacting the effective tax rate	$ 1,772	$ 935	$ 837
Tax positions not impacting the effective tax rate	-	-	-
Balance of unrecognized tax benefits	$ 1,772	$ 935	$ 837

Accrued interest for unrecognized tax benefits:

	2008	2007
	(in thousands)	
Interest accrued at beginning of year	$ 106	$ 37
Interest reclassified due to settlements	(17)	-
Interest accrued during the year	114	69
Balance at end of year	$ 203	$ 106

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

It is reasonably possible that the amount of the unrecognized benefit with respect to a majority of the Company's unrecognized tax positions will significantly increase or decrease within the next 12 months. The possible conclusion or settlement of federal or state audits could impact the balances significantly. At this time an estimate of the range of reasonably possible outcomes cannot be determined.

The IRS has audited and closed all tax returns prior to 2004. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2002.

6. FINANCING

Long-Term Debt Payable to Affiliated Trust

The Company formed a wholly-owned trust subsidiary for the purpose of issuing preferred securities. At December 31, 2008 there were no outstanding trust preferred securities.

Bank Term Loans

In 2008, the Company borrowed $80 million under a three-year term loan agreement. The proceeds were used for general corporate purposes.

Senior Notes

The Company issued $50 million of Series 2008A 6.00% Senior Notes due November 15, 2013 during the fourth quarter of 2008. Proceeds were used to repay a portion of its short-term indebtedness and for general corporate purposes, including the Company's continuous construction program. At December 31, 2008 and 2007, Mississippi Power had a total of $245 million and $195 million of senior notes outstanding, respectively.

Securities Due Within One Year

At December 31, 2008, the Company has scheduled maturities of capital leases and senior notes due within one year totaling $1.2 million and $40.0 million respectively. There were $1.1 million of capital leases due within one year at December 31, 2007.

Debt maturities through 2013 applicable to total long-term debt are as follows: $41.2 million in 2009; $1.3 million in 2010; $81.4 million in 2011; $0.6 million in 2012, and $50 million in 2013.

Pollution Control Revenue Bonds

Pollution control obligations represent loans to the Company from public authorities of funds derived from sales by such authorities of revenue bonds issued to finance pollution control facilities. The Company is required to make payments sufficient for authorities to meet principal and interest requirements of such bonds. The amount of tax-exempt pollution control revenue bonds outstanding at December 31, 2008, was $82.7 million. In September 2008, the Company was required to purchase a total of approximately $7.9 million of variable rate pollution control revenue bonds that were tendered by investors. In December 2008, the bonds were successfully remarketed. On the statement of cash flow for 2008, the $7.9 million is presented as proceeds and redemptions.

Outstanding Classes of Capital Stock

The Company currently has preferred stock, depositary preferred stock (each share of depositary preferred stock representing one-fourth of a share of preferred stock), and common stock authorized and outstanding. The Company's preferred stock and depositary preferred stock, without preference between classes, rank senior to the Company's common stock with respect to payment of dividends and voluntary or involuntary dissolution. Certain series of the preferred stock and depositary preferred stock are subject to redemption at the option of the Company on or after a specified date (typically 5 or 10 years after the date of issuance) at a redemption price equal to 100% of the liquidation amount of the stock.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

Bank Credit Arrangements

At the beginning of 2009, the Company had total unused committed credit agreements with banks of $98.5 million, all of which expire in 2009. Approximately $44 million of the facilities contain 2-year term loan options and $15 million contain 1-year term loan options. The Company expects to renew its credit facilities, as needed, prior to expiration.

Subsequent to December 31, 2008, the Company increased an existing credit agreement by $10 million. The facility matures in the third quarter of 2009 and allows for the execution of a two year term loan.

In connection with these credit arrangements, the Company agrees to pay commitment fees based on the unused portions of the commitments or to maintain compensating balances with the banks. Commitment fees average less than 1/8 of 1% for the Company. Compensating balances are not legally restricted from withdrawal.

This $98.5 million in unused credit arrangements provides required liquidity support to the Company's borrowings through a commercial paper program. At December 31, 2008, the Company had $26.3 million outstanding in commercial paper. The credit arrangements also provide support to the Company's variable rate tax-exempt pollution control bonds totaling $40.1 million. During 2008, the peak amount outstanding for short-term debt was $86.6 million and the average amount outstanding was $28.1 million. The average annual interest rate on short-term debt was 2.6% for 2008 and 5.3% for 2007.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. However, due to cost-based rate regulations, the Company has limited exposure to market volatility in commodity fuel prices and prices of electricity. The Company manages retail fuel-hedging programs implemented per the guidelines of the Mississippi PSC and wholesale fuel-hedging programs under agreements with wholesale customers. The Company also enters into hedges of forward electricity sales.

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

	2008	2007
	(in millions)	
Regulatory hedges	$(52.0)	$1.3
Cash flow hedges	-	0.9
Non-accounting hedges	-	(0.2)
Total fair value	$(52.0)	$2.0

Energy-related derivative contracts which are designated as regulatory hedges relate primarily to the Company's fuel hedging programs, where gains and losses are initially recorded as regulatory liabilities and assets, respectively, and then are included in fuel expense as they are recovered through the energy cost management clause. Gains and losses on energy-related derivatives designated as cash flow hedges are used to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred. The pre-tax gains (losses) reclassified from other comprehensive income to revenue and fuel expense were not material for any period presented and are not expected to be material for 2009. Additionally, there was no material ineffectiveness recorded in earnings for any period presented. The Company has energy-related hedges in place up to and including 2012.

All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. See Note 9 for additional information.

7. COMMITMENTS

Construction Program

The Company is engaged in continuous construction programs, currently estimated to total $163 million in 2009, $467 million in 2010, and $1.0 billion in 2011. The construction program is subject to periodic review and revision, and actual construction costs may vary from these estimates because of numerous factors. These factors include: changes in business conditions; revised load growth estimates; storm impacts; changes in environmental statutes and regulations; changes in FERC rules and regulations; Mississippi PSC approvals; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. In addition, there can be no assurance that costs related to capital expenditures will be fully recovered. At December 31, 2008, significant purchase commitments were outstanding in connection with the construction program. Capital improvements to generating, transmission, and distribution facilities, including those to meet environmental standards, will continue.

Long-Term Service Agreements

The Company has entered into a Long-Term Service Agreement (LTSA) with General Electric (GE) for the purpose of securing maintenance support for the leased combined cycle units at Plant Daniel. The LTSA provides that GE will cover all planned inspections on the covered equipment, which generally includes the cost of all labor and materials. GE is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to limits and scope specified in the contract.

In general, the LTSA is in effect through two major inspection cycles of the units. Scheduled payments to GE under the LTSA, which are subject to price escalation, are made monthly based on estimated operating hours of the units and are recognized as expense based on actual hours of operation. The Company has recognized $9.4 million, $9.7 million, and $8.4 million for 2008, 2007, and 2006, respectively, which is included in maintenance expense in the statements of income. Remaining payments to GE under this agreement are currently estimated to total $137 million over the next 13 years. However, the LTSA contains various cancellation provisions at the option of the Company.

The Company also has entered into a LTSA with Alstom Power, Inc. for the purpose of securing maintenance support for its Chevron Unit 5 combustion turbine plant. In summary, the LTSA stipulates that Alstom Power, Inc. will perform all planned maintenance on the covered equipment, which includes the cost of all labor and materials. Alstom Power, Inc is also obligated to cover the costs of unplanned maintenance on the covered equipment subject to a limit specified in the contract.

In general, this LTSA is in effect through two major inspection cycles. Scheduled payments to Alstom Power, Inc., which are subject to price escalation, are made at various intervals based on actual operating hours of the unit. Payments to Alstom Power, Inc. under this agreement are currently estimated to total $24.1 million over the remaining term of the agreement, which is approximately 9 years. However, the LTSA contains various cancellation provisions at the option of the Company. Payments made to Alstom Power, Inc. under the LTSA prior to the performance of any planned maintenance are recorded as a prepayment in the balance sheets. Inspection costs are capitalized or charged to expense based on the nature of the work performed. After this contract expires, the Company expects to replace it with a new contract with similar terms.

Fuel Commitments

To supply a portion of the fuel requirements of the generating plants, the Company has entered into various long-term commitments for the procurement of fossil fuel. In most cases, these contracts contain provisions for price escalations, minimum purchase levels, and other financial commitments. Coal commitments include forward contract purchases for sulfur dioxide and nitrogen oxide emission allowances. Natural gas purchase commitments contain fixed volumes with prices based on various indices at the time of delivery; amounts included in the chart below represent estimates based on New York Mercantile Exchange future prices at December 31, 2008.

Total estimated minimum long-term obligations at December 31, 2008, were as follows:

	Commitments	
	Natural Gas	Coal
	(in thousands)	
2009	$ 191,576	$ 368,572
2010	128,270	177,351
2011	66,372	121,436
2012	22,326	63,795
2013	22,282	23,005
2014 and thereafter	204,944	7,800
Total	$ 635,770	$ 761,959

Additional commitments for fuel will be required to supply the Company's future needs.

SCS may enter into various types of wholesale energy and natural gas contracts acting as an agent for the Company and the other traditional operating companies and Southern Power. Under these agreements, each of the traditional operating companies and Southern Power may be jointly and severally liable. The creditworthiness of Southern Power is currently inferior to the creditworthiness of the traditional operating companies. Accordingly, Southern Company has entered into keep-well agreements with the Company and each of the other traditional operating companies to ensure the Company will not subsidize or be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of Southern Power as a contracting party under these agreements.

Operating Leases

Railcar Leases

The Company and Gulf Power have jointly entered into operating lease agreements for the use of 745 aluminum railcars. The Company has the option to purchase the railcars at the greater of lease termination value or fair market value, or to renew the leases at the end of the lease term. The Company also has multiple operating lease agreements for the use of additional railcars that do not contain a purchase option. All of these leases are for the transport of coal to Plant Daniel.

The Company's share (50%) of the leases, charged to fuel stock and recovered through the fuel cost recovery clause, was $4.0 million in 2008, $4.4 million in 2007, and $4.6 million in 2006. The Company's annual railcar lease payments for 2009 through 2013 will average approximately $2.2 million and after 2013, lease payments total in aggregate approximately $2.2 million.

In addition to railcar leases, the Company has other operating leases for fuel handling equipment at Plants Daniel and Watson and operating leases for barges and tow/shift boats for the transport of coal at Plant Watson. The Company's share (50% at Plant Daniel and 100% at Plant Watson) of the leases for fuel handling was charged to fuel handling expense in the amount of $0.6 million in 2008 and $0.9 million in 2007. The Company's annual lease payments for 2009 through 2011 will average approximately $0.3 million.

The Company charged to fuel stock and recovered through fuel cost recovery the barge transportation leases in the amount of $9.8 million in 2008 and $6.2 million in 2007 related to barges and tow/shift boats. The Company's annual lease payments for 2009, with regards to these barge transportation leases, will be approximately $7.6 million.

Plant Daniel Combined Cycle Generating Units

In May 2001, the Company began the initial 10-year term of the lease agreement for a 1,064 megawatt natural gas combined cycle generating facility built at Plant Daniel (Facility). The lease arrangement provided a lower cost alternative to its cost based rate regulated customers than a traditional rate base asset. See Note 3 under "Retail Regulatory Matters – Performance Evaluation Plan" for a description of the Company's formulary rate plan.

In 2003, the Facility was acquired by Juniper Capital L.P. (Juniper), whose partners are unaffiliated with the Company. Simultaneously, Juniper entered into a restructured lease agreement with the Company. Juniper has also entered into leases with other parties unrelated to the Company. The assets leased by the Company comprise less than 50% of Juniper's assets. The Company is not required to consolidate the leased assets and related liabilities, and the lease with Juniper is considered an operating lease. The lease agreement is treated as an operating lease for accounting purposes, as well as for both retail and wholesale rate recovery purposes. For income tax purposes, the Company retains tax ownership. The initial lease term ends in 2011 and the lease includes a purchase and renewal option based on the cost of the Facility at the inception of the lease, which was $370 million. The Company is required to amortize approximately 4% of the initial acquisition cost over the initial lease term. Eighteen months prior to the end of the initial lease, the Company may elect to renew for 10 years. If the lease is renewed, the agreement calls for the Company to amortize an additional 17% of the initial completion cost over the renewal period. Upon termination of the lease, at the Company's option, it may either exercise its purchase option or the Facility can be sold to a third party.

The lease provides for a residual value guarantee, approximately 73% of the acquisition cost, by the Company that is due upon termination of the lease in the event that the Company does not renew the lease or purchase the Facility and that the fair market value is less than the unamortized cost of the Facility. A liability of approximately $5 million, $7 million, and $9 million for the fair market value of this residual value guarantee is included in the balance sheets at December 31, 2008, 2007, and 2006, respectively. Lease expenses were $26 million, $27 million, and $27 million in 2008, 2007, and 2006 respectively.

The Company estimates that its annual amount of future minimum operating lease payments under this arrangement, exclusive of any payment related to the residual value guarantee, as of December 31, 2008, are as follows:

Minimum Lease Payments	
	(in thousands)
2009	$ 28,504
2010	28,398
2011	28,291
2012	-
2013	-
2014 and thereafter	-
Total commitments	$ 85,193

8. STOCK OPTION PLAN

Southern Company provides non-qualified stock options to a large segment of the Company's employees ranging from line management to executives. As of December 31, 2008, there were 273 current and former employees of the Company participating in the stock option plan and there were 33.2 million shares of common stock remaining available for awards under this plan. The prices of options granted to date have been at the fair market value of the shares on the dates of grant. Options granted to date become exercisable pro rata over a maximum period of three years from the date of grant. The Company generally recognizes stock option expense on a straight-line basis over the vesting period which equates to the requisite service period; however for employees who are eligible for retirement the total cost is expensed at the grant date. Options outstanding will expire no later than 10 years after the date of grant, unless terminated earlier by the Southern Company Board of Directors in accordance with the stock option plan. For certain stock option awards, a change in control will provide accelerated vesting.

The estimated fair values of stock options granted in 2008, 2007, and 2006 were derived using the Black-Scholes stock option pricing model. Expected volatility was based on historical volatility of Southern Company's stock over a period equal to the expected term. The Company used historical exercise data to estimate the expected term that represents the period of time that options granted to employees are expected to be outstanding. The risk-free rate was based on the U.S. Treasury yield curve in effect at the time of grant that covers the expected term of the stock options. The following table shows the assumptions used in the pricing model and the weighted average grant-date fair value of stock options granted:

Year Ended December 31	2008	2007	2006
Expected volatility	13.1%	14.8%	16.9%
Expected term *(in years)*	5.0	5.0	5.0
Interest rate	2.8%	4.6%	4.6%
Dividend yield	4.5%	4.3%	4.4%
Weighted average grant-date fair value	$2.37	$4.12	$4.15

The Company's activity in the stock option plan for 2008 is summarized below:

	Shares Subject to Option	Weighted Average Exercise Price
Outstanding at December 31, 2007	1,477,954	$30.30
Granted	253,120	35.78
Exercised	(297,599)	28.14
Cancelled	(2,348)	25.45
Outstanding at December 31, 2008	**1,431,127**	**$31.72**
Exercisable at December 31, 2008	**937,694**	**$29.63**

The number of stock options vested and expected to vest in the future, as of December 31, 2008, was not significantly different from the number of stock options outstanding at December 31, 2008 as stated above. As of December 31, 2008, the weighted average remaining contractual terms for the options outstanding and options exercisable was 6.2 years and 5.1 years, respectively, and the aggregate intrinsic values for the options outstanding and options exercisable was $7.6 million and $6.9 million, respectively.

As of December 31, 2008, there was $0.2 million of total unrecognized compensation cost related to stock option awards not yet vested. That cost is expected to be recognized over a weighted-average period of approximately 8 months.

For the years ended December 31, 2008, 2007 and 2006, total compensation cost for stock option awards recognized in income was $0.7 million, $1.0 million and $1.1 million, respectively, with the related tax benefit also recognized in income of $0.3 million, $0.4 million and $0.4 million, respectively.

The compensation cost and tax benefits related to the grant and exercise of Southern Company stock options to the Company's employees are recognized in the Company's financial statements with a corresponding credit to equity, representing a capital contribution from Southern Company.

The total intrinsic value of options exercised during the years ended December 31, 2008, 2007, and 2006, was $3.7 million, $2.2 million, and $2.4 million, respectively. The actual tax benefit realized by the Company for the tax deductions from stock option exercises totaled $1.4 million, $0.9 million, and $0.9 million, respectively, for the years ended December 31, 2008, 2007, and 2006.

9. FAIR VALUE MEASUREMENTS

On January 1, 2008, the Company adopted FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value, and requires additional disclosures about fair value measurements. The criterion that is set forth in SFAS No. 157 is applicable to fair value measurement where it is permitted or required under other accounting pronouncements.

SFAS No. 157 defines fair value as the exit price, which is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of

observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement. As a means to illustrate the inputs used, SFAS No. 157 establishes a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

The adoption of SFAS No. 157 has not resulted in any significant changes to the methodologies used for fair value measurement. Primarily all the changes in the fair value of assets and liabilities are recorded in other comprehensive income or regulatory assets and liabilities, and thus the impact on earnings is limited to derivatives that do not qualify for hedge accounting.

The fair value measurements performed on a recurring basis and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

At December 31, 2008:	Level 1	Level 2	Level 3	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 1.3	-	$ 1.3
Cash equivalents	18.5	-	-	18.5
Total fair value	$18.5	$ 1.3	-	$19.8
Liabilities:				
Energy-related derivatives total fair value	$ -	$53.3	-	$53.3

Energy-related derivatives primarily consist of over-the-counter contracts. See Note 6 under "Financial Instruments" for additional information. The cash equivalents consist of securities with original maturities of 90 days or less. All of these financial instruments and investments are valued primarily using the market approach.

10. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial data for 2008 and 2007 are as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income After Dividends On Preferred Stock
		(in thousands)	
March 2008	**$285,416**	**$28,712**	**$16,172**
June 2008	**297,932**	**39,410**	**24,005**
September 2008	**381,415**	**58,718**	**36,217**
December 2008	**291,779**	**20,488**	**9,566**
March 2007	$256,826	$36,824	$19,636
June 2007	273,216	41,671	26,280
September 2007	333,023	59,535	34,450
December 2007	250,679	9,707	3,665

The Company's business is influenced by seasonal weather conditions.

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SELECTED FINANCIAL AND OPERATING DATA 2004-2008

Mississippi Power Company 2008 Annual Report

	2008	2007	2006	2005	2004
Operating Revenues (in thousands)	**$1,256,542**	$1,113,744	$1,009,237	$969,733	$910,326
Net Income after Dividends on Preferred Stock (in thousands)	**$85,960**	$84,031	$82,010	$73,808	$76,801
Cash Dividends on Common Stock (in thousands)	**$68,400**	$67,300	$65,200	$62,000	$66,200
Return on Average Common Equity (percent)	**13.75**	13.96	14.25	13.33	14.24
Total Assets (in thousands)	**$1,952,695**	$1,727,665	$1,708,376	$1,981,269	$1,479,113
Gross Property Additions (in thousands)	**$139,250**	$114,927	$127,290	$158,084	$70,063
Capitalization (in thousands):					
Common stock equity	**$636,451**	$613,830	$589,820	$561,160	$545,837
Preferred stock	**32,780**	32,780	32,780	32,780	32,780
Long-term debt	**370,460**	281,963	278,635	278,630	278,580
Total (excluding amounts due within one year)	**$1,039,691**	$928,573	$901,235	$872,570	$857,197
Capitalization Ratios (percent):					
Common stock equity	**61.2**	66.1	65.4	64.3	63.7
Preferred stock	**3.2**	3.5	3.6	3.8	3.8
Long-term debt	**35.6**	30.4	31.0	31.9	32.5
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
First Mortgage Bonds -					
Moody's	**-**	-	-	-	Aa3
Standard and Poor's	**-**	-	-	-	A+
Fitch	**-**	-	-	-	AA
Preferred Stock -					
Moody's	**A3**	A3	A3	A3	A3
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**A+**	A+	A+	A+	A+
Unsecured Long-Term Debt -					
Moody's	**A1**	A1	A1	A1	A1
Standard and Poor's	**A**	A	A	A	A
Fitch	**AA-**	AA-	AA-	AA-	AA-
Customers (year-end):					
Residential	**152,280**	150,601	147,643	142,077	160,189
Commercial	**33,589**	33,507	32,958	30,895	33,646
Industrial	**518**	514	507	512	522
Other	**183**	181	177	176	183
Total	**186,570**	184,803	181,285	173,660	194,540
Employees (year-end)	**1,317**	1,299	1,270	1,254	1,283

	2008	2007	2006	2005	2004
Operating Revenues (in thousands):					
Residential	**$248,693**	$230,819	$214,472	$209,546	$199,242
Commercial	**271,452**	247,539	215,451	213,093	199,127
Industrial	**258,328**	242,436	211,451	190,720	180,516
Other	**6,961**	6,420	5,812	5,501	5,428
Total retail	**785,434**	727,214	647,186	618,860	584,313
Wholesale - non-affiliates	**353,793**	323,120	268,850	283,413	265,863
Wholesale - affiliates	**100,928**	46,169	76,439	50,460	44,371
Total revenues from sales of electricity	**1,240,155**	1,096,503	992,475	952,733	894,547
Other revenues	**16,387**	17,241	16,762	17,000	15,779
Total	**$1,256,542**	$1,113,744	$1,009,237	$969,733	$910,326
Kilowatt-Hour Sales (in thousands):					
Residential	**2,121,389**	2,134,883	2,118,106	2,179,756	2,297,110
Commercial	**2,856,744**	2,876,247	2,675,945	2,725,274	2,969,829
Industrial	**4,187,101**	4,317,656	4,142,947	3,798,477	4,235,290
Other	**38,886**	38,764	36,959	37,905	40,229
Total retail	**9,204,120**	9,367,550	8,973,957	8,741,412	9,542,458
Sales for resale - non-affiliates	**5,016,655**	5,185,772	4,624,092	4,811,250	6,027,666
Sales for resale - affiliates	**1,487,083**	1,026,546	1,679,831	896,361	1,053,471
Total	**15,707,858**	15,579,868	15,277,880	14,449,023	16,623,595
Average Revenue Per Kilowatt-Hour (cents):					
Residential	**11.72**	10.81	10.13	9.61	8.67
Commercial	**9.50**	8.61	8.05	7.82	6.70
Industrial	**6.17**	5.61	5.10	5.02	4.26
Total retail	**8.53**	7.76	7.21	7.08	6.12
Wholesale	**6.99**	5.94	5.48	5.85	4.38
Total sales	**7.90**	7.04	6.50	6.59	5.38
Residential Average Annual Kilowatt-Hour Use Per Customer	**13,992**	14,294	14,480	14,111	14,357
Residential Average Annual Revenue Per Customer	**$1,640**	$1,545	$1,466	$1,357	$1,245
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**3,156**	3,156	3,156	3,156	3,156
Maximum Peak-Hour Demand (megawatts):					
Winter	**2,385**	2,294	2,204	2,178	2,173
Summer	**2,458**	2,512	2,390	2,493	2,427
Annual Load Factor (percent)	**61.5**	60.9	61.3	56.6	62.4
Plant Availability Fossil-Steam (percent)	**91.6**	92.2	81.1	82.8	91.4
Source of Energy Supply (percent):					
Coal	**58.7**	60.0	63.1	58.1	55.7
Oil and gas	**28.6**	27.1	26.1	24.4	25.5
Purchased power -					
From non-affiliates	**4.4**	3.0	3.5	5.1	6.4
From affiliates	**8.3**	9.9	7.3	12.4	12.4
Total	**100.0**	100.0	100.0	100.0	100.0

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SOUTHERN POWER COMPANY

FINANCIAL SECTION

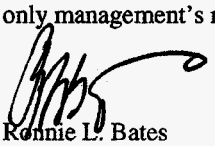
MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Southern Power Company and Subsidiary Companies 2008 Annual Report

The management of Southern Power Company (the "Company") is responsible for establishing and maintaining an adequate system of internal control over financial reporting as required by the Sarbanes-Oxley Act of 2002 and as defined in Exchange Act Rule 13a-15(f). A control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

Under management's supervision, an evaluation of the design and effectiveness of the Company's internal control over financial reporting was conducted based on the framework in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2008.

This Annual Report does not include an attestation report of the Company's independent registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Company's independent registered public accounting firm pursuant to temporary rules of the Securities and Exchange Commission that permit the Company to provide only management's report in this Annual Report.



Ronnie L. Bates
President and Chief Executive Officer

Michael W. Southern
Senior Vice President and Chief Financial Officer

February 25, 2009

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Southern Power Company

We have audited the accompanying consolidated balance sheets of Southern Power Company and Subsidiary Companies (the "Company") (a wholly owned subsidiary of Southern Company) as of December 31, 2008 and 2007, and the related consolidated statements of income, comprehensive income, common stockholder's equity, and cash flows for each of the three years in the period ended December 31, 2008. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements (pages II-387 to II-405) present fairly, in all material respects, the financial position of Southern Power Company and Subsidiary Companies at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008, in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

OVERVIEW

Business Activities

Southern Power Company and its wholly-owned subsidiaries (the Company) construct, acquire, own, and manage generation assets and sell electricity at market-based prices in the wholesale market. The Company continues to execute its strategy through a combination of acquiring and constructing new power plants and by entering into power purchase agreements (PPAs) with investor owned utilities, independent power producers, municipalities, and electric cooperatives.

In June 2008, the Company completed construction of Plant Franklin Unit 3, a combined cycle unit located in Smiths, Alabama with a nameplate capacity of 659 megawatts (MW). The Company has a PPA covering the entire output of this unit from January 2009 through December 2015.

In December 2008, the Company announced that it will build an electric generating plant in Cleveland County, North Carolina. This plant will consist of four combustion turbine natural gas generating units with a total expected generating capacity of 720 MW. The units are expected to go into commercial operation in 2012. The Company also entered into long-term PPAs for 540 MW of the generating capacity of the plant.

As of December 31, 2008, the Company had units totaling 7,555 MW nameplate capacity in commercial operation. The weighted average duration of the Company's wholesale contracts exceeds 13.3 years, which reduces remarketing risk. The Company's future earnings will depend on the parameters of the wholesale market, federal regulation, and the efficient operation of its wholesale generating assets. See FUTURE EARNINGS POTENTIAL – "FERC Matters" herein for additional information.

Key Performance Indicators

To evaluate operating results and to ensure the Company's ability to meet its contractual commitments to customers, the Company focuses on several key performance indicators. These indicators include plant availability, peak season equivalent forced outage rate (EFOR), and net income. Plant availability measures the percentage of time during the year that the Company's generating units are available to be called upon to generate (the higher the better), whereas the EFOR more narrowly defines the hours during peak demand times when the Company's generating units are not available due to forced outages (the lower the better). Net income is the primary component of the Company's contribution to Southern Company's earnings per share goal. The Company's actual performance in 2008 met or surpassed targets in these key performance areas. See RESULTS OF OPERATIONS herein for additional information on the Company's financial performance.

Earnings

The Company's 2008 earnings were $144.4 million, a $12.7 million increase over 2007. This increase was primarily the result of increased capacity sales to requirements service customers, market sales of uncontracted generating capacity, a gain on the sale of an undeveloped tract of land in 2008, a loss on the gasifier portion of the Integrated Coal Gasification Combined Cycle (IGCC) project in 2007, and the receipt of a fee for participating in an asset auction in 2008. The Company was not the successful bidder in the asset auction. These increases were partially offset by transmission service expenses and tariff penalties incurred in 2008, timing of plant maintenance activities, increased general and administrative expenses associated with the implementation of the Federal Energy Regulatory Commission (FERC) separation order, and increased depreciation associated with Plant Oleander Unit 5 and Plant Franklin Unit 3 being placed into commercial operation in December 2007 and June 2008, respectively.

The Company's 2007 earnings were $131.6 million, a $7.2 million increase over 2006. This increase was primarily the result of increased energy sales due to more favorable weather in 2007. Also contributing to the increase were additional sales from the acquisition of Plant Rowan in September 2006. These increases were partially offset by the $10.7 million after tax loss as a result of the termination of the construction of the gasifier portion of the IGCC project.

The Company's 2006 earnings were $124.4 million, a $9.7 million increase over 2005. This increase was primarily the result of new PPAs started or acquired in the period, including contracts with Piedmont Municipal Power Authority (PMPA) and EnergyUnited Electric Membership Corporation (EnergyUnited) and the PPAs related to the acquisition of Plants DeSoto and Rowan in June 2006 and September 2006, respectively. Short-term energy sales and increased sales from existing resources also contributed to this increase.

RESULTS OF OPERATIONS

A condensed statement of income follows:

	Amount	Increase (Decrease) from Prior Year		
	2008	2008	2007	2006
		(in millions)		
Operating revenues	**$ 1,313.6**	**$ 341.5**	$ 195.0	$ (4.0)
Fuel	**424.8**	**186.1**	93.4	(63.8)
Purchased power	**328.0**	**128.1**	29.3	10.7
Other operations and maintenance	**147.7**	**12.7**	39.7	14.5
Loss on IGCC project	**-**	**(17.6)**	17.6	-
Gain on sale of property	**(6.0)**	**(6.0)**	-	-
Depreciation and amortization	**88.5**	**14.5**	8.0	11.7
Taxes other than income taxes	**17.7**	**2.0**	0.2	2.3
Total operating expenses	**1,000.7**	**319.8**	188.2	(24.6)
Operating income	**312.9**	**21.7**	6.8	20.6
Other income, net	**7.6**	**4.3**	1.1	(0.2)
Interest expense	**83.2**	**4.0**	(1.0)	0.8
Income taxes	**92.9**	**9.3**	1.7	9.9
Net Income	**$ 144.4**	**$ 12.7**	$ 7.2	$ 9.7

Operating Revenues

Operating revenues in 2008 were $1.31 billion, a $341.5 million (35.1%) increase from 2007. This increase was primarily due to increased short-term energy revenues from uncontracted generating units, increased energy revenues due to higher natural gas prices, and increased revenues from a full year of operations at Plant Oleander Unit 5. These increases were partially offset by decreased demand under existing PPAs due to less favorable weather in 2008 compared to 2007. The increase in fuel revenues was accompanied by an increase in related fuel costs and did not have a significant impact on net income.

Operating revenues in 2007 were $972 million, a $195.0 million (25.1%) increase from 2006. This increase was primarily due to increased short-term energy sales, a full year of operations at Plant Rowan acquired in September 2006, new sales with EnergyUnited, increased demand under existing PPAs with affiliates as a result of favorable weather within the Southern Company service territory, and higher fuel revenues due to an increase in natural gas prices in 2007. The increase in fuel revenues was accompanied by an increase in related fuel costs and did not have a significant impact on net income.

Operating revenues in 2006 were $777.0 million, a $4.0 million (0.5%) decrease from 2005. This decrease was primarily due to reduced energy revenues as a result of lower natural gas prices. This reduction was accompanied by a reduction in related fuel costs and did not have a significant net income impact. Offsetting this energy-related reduction were increased sales from a full year of operations at Plant Oleander and new sales under PPAs with PMPA and EnergyUnited and those PPAs acquired in the DeSoto and Rowan acquisitions. See FUTURE EARNINGS POTENTIAL – "Power Sales Agreements" herein and Note 2 to the financial statements under "DeSoto and Rowan Acquisitions" for additional information.

Capacity revenues are an integral component of the Company's PPAs with both affiliate and non-affiliate customers and represent the greatest contribution to net income. Energy under PPAs is generally sold at variable cost or is indexed to published gas indices. Energy revenues also include fees for support services, fuel storage, and unit start charges. Details of these PPA capacity and energy revenues are as follows:

	2008	2007	2006
		(in millions)	
Capacity revenues –			
Affiliates	**$ 279.2**	$ 279.7	$ 279.1
Non-Affiliates	**165.2**	136.9	103.3
Total	**444.4**	416.6	382.4
Energy revenues –			
Affiliates	**263.6**	227.1	190.1
Non-Affiliates	**249.0**	189.1	144.9
Total	**512.6**	416.2	335.0
Total PPA revenues	**$ 957.0**	$ 832.8	$ 717.4

Wholesale revenues that were not covered by PPAs totaled $349.2 million in 2008, which included $95.5 million of revenues from affiliated companies. These wholesale sales were made in accordance with the Intercompany Interchange Contract (IIC), as approved by the FERC. These non-PPA wholesale revenues will vary from year to year depending on demand and the availability and cost of generating resources at each company that participates in the centralized operation and dispatch of the Southern Company fleet of generating plants (Southern Pool).

Fuel and Purchased Power Expenses

Fuel costs constitute the single largest expense for the Company. Additionally, the Company purchases a portion of its electricity needs from the wholesale market.

Details of the Company's fuel and purchased power expenditures are as follows:

	2008	2007	2006
		(in millions)	
Fuel	**$ 424.8**	$ 238.7	$ 145.2
Purchased power-non-affiliates	**132.2**	64.6	53.8
Purchased power-affiliates	**195.8**	135.3	116.9
Total fuel and purchased power expenses	**$ 752.8**	$ 438.6	$ 315.9

In 2008, fuel expense increased by $186.1 million (78.0%) compared to 2007. This increase was driven by a 58.9% increase in generation primarily due to operations at Plant Franklin Unit 3 and a 11.9% increase in the average cost of natural gas.

In 2007, fuel expense increased by $93.4 million (64.3%) compared to 2006. This increase was driven by a 43.7% increase in generation at Plants Wansley and Dahlberg and a 5.2% increase in the average cost of natural gas.

In 2006, fuel expense decreased by $63.8 million (30.5%) compared to 2005. This decrease was driven by a 25.4% reduction in the average cost of natural gas. Gas prices in 2006 were lower and had less weather-driven volatility than the previous year. The fuel price decrease was partially offset by volume increases primarily from increased generation at Plants Wansley and Dahlberg.

Demand for natural gas in the United States increased in 2007 and the first half of 2008. However, natural gas supplies have increased in the last half of 2008 as a result of increased production and higher storage levels due to weak industrial demand. Natural gas prices moderated in the second half of 2008 as the result of a recessionary economy. The Company's PPAs generally provide that the purchasers are responsible for substantially all of the cost of fuel. Consequently, any increase or decrease in fuel costs is accompanied by an increase or decrease in related fuel revenues and does not have a significant impact on net income.

Purchased power expense increased $128.1 million (64.1%) in 2008 when compared to 2007, primarily due to a 107.9% increase in the average cost of purchased power. Purchased power volume in 2008 decreased 21.0% compared to 2007. Purchased power expense increased $29.3 million (17.1%) in 2007 when compared to 2006, primarily due to increased purchases of lower cost energy resources from the Southern Pool and non-affiliates and contracts with Georgia Electric Membership Corporation and Dalton Utilities. Purchased power expense increased $10.7 million (6.6%) in 2006 when compared to 2005, due to purchases from the Southern Pool and contracts with PMPA and Dalton Utilities.

Purchased power expenses will vary depending on demand and the availability and cost of generating resources available throughout the Southern Company system and other contract resources. Load requirements are submitted to the Southern Pool on an hourly basis and are fulfilled with the lowest cost alternative, whether that is generation owned by the Company, affiliate-owned generation, or external purchases.

Other Operations and Maintenance Expenses

In 2008, other operations and maintenance expenses increased $12.7 million (9.4%) compared to 2007. This increase was due primarily to the timing of plant maintenance activities and additional administrative and general expenses as a result of costs incurred to implement the FERC compliance plan. See FUTURE EARNINGS POTENTIAL – "FERC Matters – Intercompany Interchange Contract" herein and Note 3 to the financial statements under "FERC Matters – Intercompany Interchange Contract" for additional information.

In 2007, other operations and maintenance expenses increased $39.7 million (41.7%) compared to 2006. This increase was due primarily to a full year of operations at Plant DeSoto and Plant Rowan acquired in June 2006 and September 2006, respectively, and additional administrative and general expenses as a result of costs incurred to implement the FERC compliance plan. See FUTURE EARNINGS POTENTIAL – "FERC Matters – Intercompany Interchange Contract" herein, Note 2 to the financial statements under "DeSoto and Rowan Acquisitions," and Note 3 to the financial statements under "FERC Matters – Intercompany Interchange Contract" for additional information.

In 2006, other operations and maintenance expenses increased $14.5 million (17.9%) compared to 2005. This increase was primarily the result of the operation of new generating units from acquisitions of Plant Oleander in June 2005, Plant DeSoto in June 2006, and Plant Rowan in September 2006. See Note 2 to the financial statements under "DeSoto and Rowan Acquisitions" and "Oleander Acquisition" for additional information.

Loss on IGCC Project

In November 2007, the Company and the Orlando Utilities Commission (OUC) mutually agreed to terminate the construction of the gasifier portion of the IGCC project. The Company has continued construction of the gas-fired combined cycle generating facility, owned by OUC. The Company recorded a loss in the fourth quarter 2007 of approximately $17.6 million related to the cancellation of the gasifier portion of the IGCC project. This loss consists of the write-off of construction costs of $14.0 million and an accrual for termination payments of $3.6 million. All termination payments were completed in 2008. See FUTURE EARNINGS POTENTIAL – "Construction Projects - IGCC" herein and Note 4 to the financial statements under "Integrated Coal Gasification Combined Cycle (IGCC)" for additional information.

Gain on Sale of Property

In January 2008, the Company recorded a gain of $6.0 million on the sale of an undeveloped tract of land.

Depreciation and Amortization

In 2008, depreciation and amortization increased $14.5 million (19.7%) compared to 2007. This increase was primarily due to the completion of Plant Oleander Unit 5 in December 2007 and Plant Franklin Unit 3 in June 2008 and higher depreciation rates implemented in January 2008. See FUTURE EARNINGS POTENTIAL – "Other Matters" herein for additional information regarding the Company's ongoing review of depreciation estimates.

Depreciation and amortization increased $8.0 million (12.2%) and $11.7 million (21.6%) in 2007 and 2006, respectively. These increases were primarily the result of additional depreciation related to Plants DeSoto and Rowan acquired in June 2006 and September 2006, respectively, Plant Oleander acquired in June 2005, and higher depreciation rates from a depreciation study adopted in March 2006. See Note 1 to the financial statements under "Depreciation" and Note 2 to the financial statements under "DeSoto and Rowan Acquisitions" and "Oleander Acquisition" for additional information.

Taxes Other Than Income Taxes

In 2008, taxes other than income taxes increased $2.0 million (12.4%) compared to 2007. This increase was primarily due to property taxes related to the completion of Plant Oleander Unit 5 and Plant Franklin Unit 3 in December 2007 and June 2008, respectively.

The 2007 increase in taxes other than income taxes was not material.

In 2006, taxes other than income taxes increased $2.3 million (17.4%) compared to 2005. This increase was primarily due to incremental ad valorem taxes on new assets: Plants DeSoto and Rowan acquired in June 2006 and September 2006, respectively, and Plant Oleander acquired in June 2005. See Note 2 to the financial statements under "DeSoto and Rowan Acquisitions" and "Oleander Acquisition" for additional information.

Other Income (Expense), Net

Other income (expense), net increased $4.3 million (131.1%) in 2008. This increase was primarily due to a $6.4 million fee received in 2008 for participating in an asset auction. The Company was not the successful bidder in the asset auction.

Changes in other income, net in 2007 and 2006 were primarily the result of unrealized gains and losses on derivative energy contracts. See FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 6 to the financial statements under "Financial Instruments" for additional information.

Interest Expense, Net of Amounts Capitalized

In 2008, interest expense increased $4.0 million (5.1%) compared to 2007. This increase was primarily the result of a decrease in capitalized interest as a result of the completion of Plant Oleander Unit 5 in December 2007 and Plant Franklin Unit 3 in June 2008, partially offset by a decrease in short-term borrowing levels in 2008.

In 2007, interest expense decreased $1.0 million (1.2%) compared to 2006. This decrease was primarily due to additional capitalized interest of $10.9 million on active construction projects and reduced interest on commercial paper of $2.0 million due to lower borrowing levels. This decrease was partially offset by $11.9 million increase in interest on $200 million of senior notes that were issued in November 2006.

In 2006, interest expense increased $0.8 million (1.0%) compared to 2005. This increase was primarily the result of additional debt incurred for acquisitions. This increase was offset by $5.6 million of interest capitalized on active construction projects. For additional information, see FUTURE EARNINGS POTENTIAL – "Construction Projects" herein, Note 4 to the financial statements under "Integrated Coal Gasification Combined Cycle (IGCC)," and Note 7 to the financial statements under "Expansion Program."

Income Taxes

Income taxes increased $9.3 million (11.2%) in 2008, $1.7 million (2.1%) in 2007, and $9.9 million (13.9%) in 2006 primarily due to higher pre-tax earnings from 2006 through 2008 and changes in the production activities deduction.

Effects of Inflation

When inflation exceeds projections used in market, term, and cost evaluations performed at contract initiation, the effects of inflation can create an economic loss. In addition, the income tax laws are based on historical costs. Therefore inflation creates an economic loss as the Company is recovering its costs of investments in dollars that could have less purchasing power. While the inflation rate has been relatively low in recent years, it continues to have an adverse effect on the Company due to large investment in utility plant with long economic lives. Conventional accounting for historical costs does not recognize this economic loss or the partially offsetting gain that arises through financing facilities with fixed money obligations such as long-term debt.

FUTURE EARNINGS POTENTIAL

General

The results of operations for the past three years are not necessarily indicative of future earnings potential. The level of the Company's future earnings depends on numerous factors that affect the opportunities, challenges, and risks of the Company's competitive wholesale business. These factors include the Company's ability to achieve sales growth while containing costs. Another major factor is federal regulatory policy, which may impact the Company's level of participation in the market. The level of future earnings also depends on numerous factors including regulatory matters (such as those related to affiliate contracts), creditworthiness

of customers, total generating capacity available in the Southeast, the successful remarketing of capacity as current contracts expire, and the Company's ability to execute its acquisition strategy. Recent recessionary conditions may negatively impact capacity revenues. The timing and extent of the economic recovery will impact future earnings.

The Company's system generating capacity increased 659 MW due to the completion of Franklin Unit 3 in June 2008. In general, the Company has constructed or acquired new generating capacity only after entering into long-term capacity contracts for the new facilities which are optimized by limited energy trading activities. See FUTURE EARNINGS POTENTIAL – "Construction Projects" herein for additional information.

Power Sales Agreements

The Company's sales are primarily through long-term PPAs. The Company is working to maintain and expand its share of the wholesale markets. Recent oversupply of generating capacity in the market is being reduced and the Company expects that many areas of the market will need capacity beyond 2014.

The Company's PPAs consist of two types of agreements. The first type, referred to as a unit or block sale, is a customer purchase from a dedicated plant unit where all or a portion of the generation from that unit is reserved for that customer. The Company typically has the ability to serve the unit or block sale customer from an alternate resource. The second type, referred to as requirements service, provides that the Company serve the customer's capacity and energy requirements from a combination of the customer's own generating units and from Company resources not dedicated to serve unit or block sales. The Company has rights to purchase power provided by the requirements customers' resources when economically viable.

The Company has entered into the following PPAs over the past 3 years:

	Date	Megawatts	Plant	Contract Term
2008				
North Carolina Municipal Power Agency No. 1 (NCMPA1)	December 2008	180	Cleveland	1/12-12/31
North Carolina Electric Membership Corporation (NCEMC) [a]	November 2008	180	Cleveland	1/12-12/36
NCEMC[a]	November 2008	180 [b]	Cleveland	1/12-12/36
EnergyUnited	November 2008	100	Purchased [c]	1/12-12/21
The Energy Authority, Inc.	August 2008	151	Rowan	1/11-12/14
Georgia Electric Membership Corporations (EMCs) [d]	July 2008	500[e]	Unassigned	1/10-12/34[d]
Florida Municipal Power Agency (FMPA) [f]	July 2008	85	Stanton	10/13-9/23
2007				
Progress Energy Carolina Inc.	December 2007	155	Rowan	1/10-12/10
Progress Energy Carolina Inc.	December 2007	160	Wansley	1/11-12/11
Georgia Power	April 2007	561	Wansley	6/10-5/17
Georgia Power	April 2007	292	Dahlberg	6/10-5/25
Progress Energy Carolina Inc.	February 2007	150	Rowan	1/10-12/19
2006				
Gulf Power	October 2006	292	Dahlberg	6/09-5/14
Duke Power [g]	September 2006	152	Rowan	9/06-12/10
Duke Power [g]	September 2006	304	Rowan	9/06-12/10
NCMPA1 [g]	September 2006	50	Rowan	9/06-12/10
NCMPA1 [g]	September 2006	150	Rowan	1/11-12/30
EnergyUnited	May 2006	149 [e]	Unassigned	9/06-12/10
EnergyUnited	May 2006	335 [e]	Unassigned	1/11-12/25
EnergyUnited	May 2006	161[h]	Rowan	1/11-12/25
Constellation Energy Group, Inc. (Constellation) [i]	April 2006	621	Franklin	1/09-12/15
Seminole Electric Cooperative, Inc.	February 2006	465	Oleander	1/10-12/15
FMPA	February 2006	162	Oleander	12/07 -12/27

(a) Subject to approval by the Rural Utilities Service.
(b) Power purchases under this agreement will increase over the term of the agreement. 45 MWs will be sold from 2012 through 2016, 90 MWs will be sold from 2017 through 2018, and 180 MWs will be sold from 2019 through 2036.
(c) Power to serve this agreement will be purchased under a third party agreement for resale to EnergyUnited. The purchases will be resold at cost.
(d) These agreements are extensions of current agreements with ten Georgia EMCs. Eight agreements were extended from 2010 through 2031and two agreements were extended from 2013 through 2034.
(e) Represents average annual capacity purchases.
(f) This agreement is an extension of the current agreement with FMPA for Plant Stanton.
(g) Assumed contract through the Plant Rowan acquisition in 2006.
(h) PPA was amended in 2008 reducing MWs purchased from 205 to 161.
(i) Contract was assumed by Constellation from Progress Ventures, Inc. in 2007.

The Company has PPAs with some of Southern Company's traditional operating companies and with other investor owned utilities, independent power producers, municipalities, and electric cooperatives. Although some of the Company's PPAs are with the traditional operating companies, the Company's generating facilities are not in the traditional operating companies' regulated rate bases, and the Company is not able to seek recovery from the traditional operating companies' ratepayers for construction, repair, environmental, or maintenance costs. The Company expects that the capacity payments in the PPAs will produce sufficient cash flow to cover costs, pay debt service, and provide an equity return. However, the Company's overall profit will depend on numerous factors, including efficient operation of its generating facilities.

As a general matter, existing PPAs provide that the purchasers are responsible for either procuring the fuel or reimbursing the Company for the cost of fuel relating to the energy delivered under such PPAs. To the extent a particular generating facility does not meet the operational requirements contemplated in the PPAs, the Company may be responsible for excess fuel costs. With respect to fuel transportation risk, most of the Company's PPAs provide that the counterparties are responsible for transporting the fuel to the particular generating facility.

Fixed and variable operation and maintenance costs will be recovered through capacity charges based on dollars-per-kilowatt year or energy charges based on dollars-per-MW hour. In general, the Company has long-term service contracts with General Electric and Siemens AG to reduce its exposure to certain operation and maintenance costs relating to such vendors' applicable equipment. See Note 7 to the financial statements under "Long-Term Service Agreements" for additional information.

Many of the Company's PPAs have provisions that require the posting of collateral or an acceptable substitute guarantee in the event that Standard & Poor's or Moody's downgrades the credit ratings of the counterparty to an unacceptable credit rating or the counterparty is not rated or fails to maintain a minimum coverage ratio. The PPAs are expected to provide the Company with a stable source of revenue during their respective terms.

The Company has entered into long-term power sales agreements for an average of 83% of its available capacity for the next 10 years as follows:

	2009-2010	2011-2012	2013-2014	2015-2016	2017-2018
Average available capacity [a]	7,709	8,015	8,411	8,271	8,131
Average contracted capacity	7,171	7,064	7,348	6,617	5,325
Percent contracted	**93%**	**88%**	**87%**	**80%**	**66%**

(a). Includes confirmed third party power purchases for 2009 through 2018.

Environmental Matters

The Company's operations are subject to extensive regulation by state and federal environmental agencies under a variety of statutes and regulations governing environmental media, including air, water, and land resources. Applicable statutes include the Clean Air Act; the Clean Water Act; the Comprehensive Environmental Response, Compensation, and Liability Act; the Resource Conservation and Recovery Act; the Toxic Substances Control Act; the Emergency Planning & Community Right-to-Know Act; the Endangered Species Act; and related federal and state regulations. Compliance with possible additional federal or state legislation or regulations related to global climate change, air quality, or other environmental and health concerns can also significantly affect the Company.

New environmental legislation or regulations, such as requirements related to greenhouse gases, or changes to existing statutes or regulations, could affect many areas of the Company's operations. While the Company's PPAs generally contain provisions that permit charging the counterparty with some of the new costs incurred as a result of changes in environmental laws and regulations, the full impact of any such regulatory or legislative changes cannot be determined at this time.

Because the Company's units are newer gas-fired generating facilities, costs associated with environmental compliance for these facilities have been less significant than for similarly situated coal-fired generating facilities or older gas-fired generating facilities. Environmental, natural resource, and land use concerns, including the applicability of air quality limitations, the availability of water withdrawal rights, uncertainties regarding aesthetic impacts such as increased light or noise, and concerns about potential adverse health impacts, can, however, increase the cost of siting and operating any type of future electric generating facility. The impact of such statutes and regulations on the Company cannot be determined at this time.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such potential litigation against the Company cannot be determined at this time.

Global Climate Issues

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions and renewable energy standards continue to be strongly considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. The ultimate outcome of these proposals cannot be determined at this time; however, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

In April 2007, the U.S. Supreme Court ruled that the Environmental Protection Agency (EPA) has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that will follow from this response may have implications for both new and existing stationary sources, such as power plants. The ultimate outcome of these rulemaking activities cannot be determined at this time; however, as with the current legislative proposals, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition.

In addition, some states are considering or have undertaken actions to regulate and reduce greenhouse gas emissions. For example, on June 25, 2008, Florida's Governor signed comprehensive energy-related legislation that includes authorization for the Florida Department of Environmental Protection to adopt rules for a cap-and-trade regulatory program to address greenhouse gas emissions from electric utilities, conditioned upon their ratification by the legislature no sooner than the 2010 legislative session. This legislation also authorizes the Florida Public Service Commission to adopt a renewable portfolio standard for public utilities, subject to legislative ratification. The impact of this and any similar legislation on the Company will depend on the future development, adoption, legislative ratification, implementation, and potential legal challenges to rules governing greenhouse gas emissions and mandates regarding the use of renewable energy, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2012 timeframe, with a conclusion to this round of negotiations targeted for the end of 2009. The outcome and impact of the international negotiations cannot be determined at this time.

The Company continues to evaluate its future energy and emission profiles and is participating in voluntary programs to reduce greenhouse gas emissions and to help develop and advance technology to reduce emissions.

Carbon Dioxide Litigation

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $0.7 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed its prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Intercompany Interchange Contract

The majority of the Company's generation fleet is operated under the IIC, as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the traditional operating companies, the Company, and Southern Company Services, Inc., as agent, under the terms of which the Southern Pool is operated, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining the Company as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of the Company, the FERC authorized the Company's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms and Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of Southern Power. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. In November 2007, Southern Company notified the FERC that the plan had been implemented. On December 12, 2008, the FERC division of audits issued for public comment its final audit report pertaining to compliance implementation and related matters. No comments challenging the audit report's findings were submitted. A decision is now pending from the FERC. The annual cost of implementing the order is approximately $7.0 million. The ultimate outcome of this matter cannot be determined at this time.

Income Tax Matters

Legislation

On February 17, 2009, President Obama signed into law the American Recovery and Reinvestment Act of 2009 (ARRA). Major tax incentives in the ARRA include an extension of bonus depreciation and multiple renewable energy incentives. These incentives could have a significant impact on the Company's future cash flow and net income. Additionally, the ARRA includes programs for renewable energy, transmission and smart grid enhancement, fossil energy and research, and energy efficiency and conservation. The ultimate impact cannot be determined at this time.

Internal Revenue Code Section 199 Domestic Production Deduction

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the Internal Revenue Code of 1986, as amended, Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. The Internal Revenue Service (IRS) has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction to conform to the agreement. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements. See Note 5 to the financial statements under "Effective Tax Rate" for additional information.

Construction Projects

Cleveland County Units 1-4

On December 5, 2008, the Company announced that it will build an electric generating plant in Cleveland County, North Carolina. The plant will consist of four combustion turbine natural gas generating units with a total generating capacity of 720 MW. The units are expected to go into commercial operation in 2012. Costs incurred through December 31, 2008 were $5.2 million. The total estimated construction cost is expected to be between $350 million and $400 million, which is included in the capital program estimates described under FINANCIAL CONDITION AND LIQUIDITY – "Capital Requirements and Contractual Obligations" herein.

The Company has also entered into PPAs with NCEMC and NCMPA1 for a portion of the generating capacity from the plant that will begin in 2012 and expire in 2036 and 2031, respectively. NCEMC will purchase 180 MW of capacity that will be supported by one unit at the plant and will purchase capacity from a second unit at the plant that will increase to 180 MW over a seven year phase-in

period. NCMPA1 will purchase 180 MW from a third unit at the plant. The NCEMC PPAs are subject to approval by the Rural Utilities Service. The final outcome of this matter cannot now be determined.

Plant Franklin Unit 3

The Company completed construction of Plant Franklin Unit 3 in June 2008. Total costs incurred were $309.9 million. The unit is a natural gas-fueled combined cycle located in Smiths, Alabama with a nameplate capacity of 659 MW. The unit will be used to provide annual capacity for a PPA with Constellation from 2009 through 2015.

Plant Oleander Unit 5

The Company completed construction of Plant Oleander Unit 5 in December 2007. Total costs incurred were $58.0 million. This unit is a combustion turbine with a nameplate capacity of 163 MW located in Brevard County, Florida. This unit is contracted to provide annual capacity for a PPA with FMPA from 2007 through 2027.

IGCC

In December 2005, the Company and OUC executed definitive agreements for development of a 285-MW IGCC project in Orlando, Florida. The definitive agreements provided that the Company would own at least 65% of the gasifier portion of the IGCC project. OUC would own the remainder of the gasifier portion and 100% of the combined cycle portion of the IGCC project. The Company signed cooperative agreements with the U.S. Department of Energy (DOE) that provided up to $293.75 million in grant funding for the gasification portion of this project. The IGCC project was expected to begin commercial operation in 2010. Due to uncertainty surrounding potential state regulations relating to greenhouse gas emissions, the Company and OUC mutually agreed to terminate the construction of the gasifier portion of the IGCC project in November 2007. The Company has continued construction of the gas-fired combined cycle generating facility for OUC under a fixed-price, long-term contract for engineering, procurement, and construction services. The Company expects the construction to be completed substantially at the contractual fixed price and no profit or loss is anticipated at this time. The Company recorded a loss in the fourth quarter 2007 of approximately $17.6 million related to cancellation of the gasifier portion of the IGCC project. This amount is net of reimbursements from OUC and the DOE. This loss consists of the write-off of construction costs of $14.0 million and an accrual for termination costs of $3.6 million. All termination costs were paid in 2008. As part of the termination agreement with OUC, the Company sold a tract of land in Orange County, Florida to OUC. The Company recorded a gain of approximately $6 million on this sale in the first quarter 2008.

Other Matters

The Company completed depreciation studies in 2006 and 2008. The composite depreciation rates for its property, plant, and equipment were updated in these studies. These changes in estimates arise from changes in useful life assumptions for certain components of plant in service. These changes increased depreciation expense prospectively beginning March 1, 2006 and January 1, 2008 and reduced net income. The net income impacts of these changes were $3.8 million and $2.8 million, respectively. See Note 1 to the financial statements under "Depreciation" for additional information. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could have a material impact on net income in the near term. See ACCOUNTING POLICIES - "Application of Critical Accounting Policies and Estimates" herein for additional information.

From time to time, the Company is involved in various matters being litigated and regulatory matters that could affect future earnings. In addition, the Company is subject to certain claims and legal actions arising in the ordinary course of business. The Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any arising from such current proceedings would have a material adverse effect on the Company's financial statements. See Note 3 to the financial statements for information regarding material issues.

ACCOUNTING POLICIES

Application of Critical Accounting Policies and Estimates

The Company prepares its consolidated financial statements in accordance with accounting principles generally accepted in the United States. Significant accounting policies are described in Note 1 to the financial statements. In the application of these policies, certain estimates are made that may have a material impact on the Company's results of operations and related disclosures. Different assumptions and measurements could produce estimates that are significantly different from those recorded in the financial statements. Senior management has reviewed and discussed the critical accounting policies and estimates described below with the Audit Committee of Southern Company's Board of Directors.

Revenue Recognition

The Company's revenue recognition depends on appropriate classification and documentation of transactions in accordance with Financial Accounting Standards Board (FASB) Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended and interpreted (SFAS No. 133). In general, the Company's power sale transactions can be classified in one of four categories: non-derivatives, normal sales, cash flow hedges, and mark to market. For more information on derivative transactions, see FINANCIAL CONDITION AND LIQUIDITY – "Market Price Risk" herein and Notes 1 and 6 to the financial statements under "Financial Instruments." The Company's revenues are dependent upon significant judgments used to determine the appropriate transaction classification, which must be documented upon the inception of each contract. Factors that must be considered in making these determinations include:

- Assessing whether a sales contract meets the definition of a lease;
- Assessing whether a sales contract meets the definition of a derivative;
- Assessing whether a sales contract meets the definition of a capacity contract;
- Assessing the probability at inception and throughout the term of the individual contract that the contract will result in physical delivery;
- Ensuring that the contract quantities do not exceed available generating capacity (including purchased capacity);
- Identifying the hedging instrument, the hedged transaction, and the nature of the risk being hedged; and
- Assessing hedge effectiveness at inception and throughout the contract term.

Normal Sale and Non-Derivative Transactions

The Company has entered into capacity contracts that provide for the sale of electricity and that involve physical delivery in quantities within the Company's available generating capacity. These contracts either do not meet the definition of a derivative or are designated as normal sales, thus exempting them from fair value accounting under SFAS No. 133. As a result, such transactions are accounted for as executory contracts; additionally, the related revenue is recognized in accordance with Emerging Issues Task Force (EITF) No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts" on an accrual basis in amounts equal to the lesser of the levelized amount or the amount billable under the contract, over the respective contract periods. Revenues are recorded on a gross or net basis in accordance with EITF No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Agent." Revenues from transactions that do not meet the definition of a derivative are also recorded in this manner. Contracts recorded on the accrual basis represented the majority of the Company's operating revenues for the year ended December 31, 2008.

Cash Flow Hedge Transactions

The Company designates other derivative contracts for the sale of electricity as cash flow hedges of anticipated sale transactions. These contracts are marked to market through other comprehensive income over the life of the contract. Realized gains and losses are then recognized in revenues as incurred.

Mark to Market Transactions

Contracts for sales of electricity that are not normal sales and are not designated as cash flow hedges are marked to market and recorded directly through net income. Net unrealized gains on such contracts were not material for the years ended December 31, 2008, 2007, or 2006.

Percentage of Completion

The Company is currently engaged in a long-term contract for engineering, procurement, and construction services to build a combined cycle unit for OUC. Construction activities commenced in 2006 and are expected to be complete by the end of 2009. Revenues and costs are recognized using the percentage-of-completion method. The Company utilizes the cost-to-cost approach as this method is less subjective than relying on assessments of physical progress. The percentage of completion represents the percentage of the total costs incurred to the estimated total cost of the contract. Revenues and costs are recognized by applying this percentage to the total revenues and estimated costs of the contract.

Asset Impairments

The Company's investments in long-lived assets are primarily generation assets, whether in service or under construction. The Company evaluates the carrying value of these assets under FASB Statement No. 144, "Accounting for the Impairment or Disposal of Long-lived Assets," whenever indicators of potential impairment exist. Examples of impairment indicators could include significant changes in construction schedules, current period losses combined with a history of losses or a projection of continuing losses, a significant decrease in market prices, and the inability to remarket generating capacity for an extended period. If an indicator exists, the asset is tested for recoverability by comparing the asset carrying value to the sum of the undiscounted expected future cash flows directly attributable to the asset. A high degree of judgment is required in developing estimates related to these evaluations, which are based on projections of various factors, including the following:

- Future demand for electricity based on projections of economic growth and estimates of available generating capacity;
- Future power and natural gas prices, which have been quite volatile in recent years; and
- Future operating costs.

Acquisition Accounting

The Company has been engaged in a strategy of acquiring assets. The Company has accounted for these acquisitions under the purchase method in accordance with FASB Statement No. 141, "Business Combinations." Accordingly, the Company has included these operations in the consolidated financial statements from the respective date of acquisition. The purchase price of each acquisition was allocated to the identifiable assets and liabilities based on a valuation prepared by a third party. The Company adopted FASB Statement No. 141 (revised 2007), "Business Combinations" (SFAS No. 141R) effective January 1, 2009. Any costs incurred by the Company in assessing potential acquisitions that will close after December 31, 2008 have been expensed as incurred.

Contingent Obligations

The Company is subject to a number of federal and state laws and regulations, as well as other factors and conditions that potentially subject it to environmental, litigation, income tax, and other risks. See FUTURE EARNINGS POTENTIAL herein and Note 3 to the financial statements for more information regarding certain of these contingencies. The Company periodically evaluates its exposure to such risks and, in accordance with generally accepted accounting principles, records reserves for those matters where a non-tax-related loss is considered probable and reasonably estimable and records a tax asset or liability if it is more likely than not that a tax position will be sustained. The adequacy of reserves can be significantly affected by external events or conditions that can be unpredictable; thus, the ultimate outcome of such matters could materially affect the Company's financial statements. These events or conditions include the following:

- Changes in existing state or federal regulation by governmental authorities having jurisdiction over air quality, water quality, control of toxic substances, hazardous and solid wastes, and other environmental matters.
- Changes in existing income tax regulations or changes in IRS or state revenue department interpretations of existing regulations.
- Identification of sites that require environmental remediation or the filing of other complaints in which the Company may be asserted to be a potentially responsible party.
- Identification and evaluation of other potential lawsuits or complaints in which the Company may be named as a defendant.
- Resolution or progression of new or existing matters through the legislative process, the court systems, the IRS, the FERC, or the EPA.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by management. The primary assets in property, plant, and equipment are power plants, all of which have an estimated composite life ranging from 29 to 37 years. These lives reflect a weighted average of the significant components (retirement units) that make up the plants. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term. See Note 1 to the financial statements under "Depreciation" for a discussion of changes in depreciation assumptions made by the Company effective January 1, 2008.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

New Accounting Standards

Business Combinations

In December 2007, the FASB issued SFAS No. 141R. The Company adopted SFAS No. 141R on January 1, 2009. The adoption of SFAS No. 141R could have an impact on the accounting for any business combinations completed by the Company after January 1, 2009. Any costs incurred by the Company in assessing potential acquisitions that will close after December 31, 2008 have been expensed as incurred.

In December 2007, the FASB issued FASB Statement No. 160, "Non-controlling Interests in Consolidated Financial Statements" (SFAS No. 160). SFAS No. 160 amends Accounting Research Bulletin No. 51, "Consolidated Financial Statements" to establish accounting and reporting standards for the non-controlling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. It clarifies that a non-controlling interest in a subsidiary should be reported as equity in the consolidated financial statements and establishes a single method of accounting for changes in a parent's ownership interest in a subsidiary that do not result in deconsolidation. The Company adopted SFAS No. 160 on January 1, 2009 with no material impact to the financial statements.

FINANCIAL CONDITION AND LIQUIDITY

Overview

The Company's financial condition remained stable at December 31, 2008. Throughout the recent turmoil in the financial markets, the Company has maintained cash balances to cover the majority of its capital needs and has had limited need to issue commercial paper or draw on committed credit arrangements. There was no commercial paper outstanding as of December 31, 2008. Subsequent to December 31, 2008, the Company issued a small amount of overnight commercial paper. Southern Power intends to continue to monitor its access to short-term and long-term capital markets as well as its bank credit arrangements as needed to meet its future capital and liquidity needs. No changes in bank credit arrangements were experienced during 2008 although market rates for committed credit have increased and the Company may be subject to higher costs as its existing facilities are replaced or renewed. The Company experienced no material counterparty credit losses as a result of the turmoil in the financial markets. The ultimate impact on future financing costs as a result of the financial turmoil cannot be determined at this time. See "Sources of Capital" herein for additional information on lines of credit.

Net cash provided from operating activities totaled $264.3 million in 2008, decreasing 19.4% from 2007. This decrease is primarily due to cash outflows for engineering, procurement, and construction services to build a combined cycle unit for OUC. The OUC contract is not expected to have any positive or negative cash impacts to the Company over the term of the contract as the Company is not anticipating a profit or loss from this transaction at this time. Net cash used for investing activities totaled $85.8 million in 2008, decreasing 53.4% from 2007. This decrease was primarily due to the completion of Plant Oleander Unit 5 in 2007 and the completion of Plant Franklin Unit 3 in 2008. Gross property additions to utility plant of $50.0 million in 2008 were primarily related to the completion of Plant Franklin Unit 3. Net cash used for financing activities was $140.6 million in 2008, decreasing 14.9% from 2007. This decrease was primarily due to reduced levels of short-term debt in 2008.

Net cash provided from operating activities totaled $315.4 million in 2007, increasing 29.8% from 2006. This increase was primarily due to the increase in sales due to favorable weather and cash received under billings for the engineering, procurement, and construction services to build a combined cycle unit for OUC. Net cash used for investing activities totaled $183.9 million in 2007, decreasing 61% from 2006. This decrease was primarily due to the acquisition of Plants DeSoto and Rowan in June 2006 and September 2006, respectively. Gross property additions to utility plant of $139.2 million in 2007 were primarily related to the on-going construction activity at Plant Franklin Unit 3 and the completion of construction at Plant Oleander Unit 5. Net cash used for financing activities was $161.5 million in 2007 compared to $233.4 million provided to the Company in 2006. This change was primarily due to the cash proceeds of $200 million from the issuance of 30-year senior notes in 2006 and borrowings and equity contributions to finance the acquisitions of Plants DeSoto and Rowan.

Net cash provided from operating activities totaled $243.0 million in 2006, increasing 20.6% from 2005. This increase was primarily due to the increase in sales due to PPAs started or acquired during the period and a reduction of energy revenues due to lower natural gas prices resulting in reduced working capital levels. Net cash used for investing activities totaled $474.1 million in 2006, increasing 96.6% from 2005. This increase was due primarily to the acquisition of Plants DeSoto and Rowan in June 2006 and September 2006, respectively. Net cash provided by financing activities in 2006 totaled $233.4 million, increasing 453.1% from 2005. This increase was primarily due to the cash proceeds of $200 million from the issuance of 30-year senior notes in 2006 and borrowings and equity contributions to finance the acquisitions of Plants DeSoto and Rowan.

Significant asset changes in the balance sheet during 2008 include increases in accounts receivable related to higher energy revenues due to an increase in natural gas prices, increases in long-term service agreements prepayments due to the timing of outage activities, and an increase in cash due to a reduction of investing activities of the Company in 2008 due to the completion of construction projects at Plant Oleander Unit 5 in December 2007 and Plant Franklin Unit 3 in June 2008.

Significant asset changes in the balance sheet during 2007 include lower cash balances as available amounts were used to reduce short-term debt and an increase in assets from risk management activities primarily due to mark to market changes on energy derivative contracts.

Significant liability and stockholder's equity changes in the balance sheet during 2008 include the payment of short-term debt obligations, increases in affiliate payables due to increases in natural gas and purchased power prices, a reduction of other current liabilities due to payment of IGCC termination costs, and a decrease in the net billings in excess of cost on the OUC construction contract due to on-going construction activities. In 2008, the Company also paid $94.5 million in dividends to Southern Company.

Significant liability and stockholder's equity changes in the balance sheet during 2007 include a reduction of short-term debt, an increase in billings received in excess of costs on the OUC construction contract, and payment of $89.8 million in dividends to Southern Company.

Sources of Capital

The Company may use operating cash flows, external funds, or equity capital or loans from Southern Company to finance any new projects, acquisitions, and ongoing capital requirements. The Company expects to generate external funds from the issuance of unsecured senior debt and commercial paper or utilization of credit arrangements from banks. However, the amount, type, and timing of any financings, if needed, will depend upon regulatory approval, prevailing market conditions, and other factors.

The Company's current liabilities frequently exceed current assets due to the use of short-term indebtedness as a funding source, as well as cash needs which can fluctuate significantly due to the seasonality of the business. To meet liquidity and capital resource requirements, at December 31, 2008, the Company had $400 million of committed credit arrangements with banks that expire in 2012. There were no borrowings under this facility outstanding at December 31, 2008. Proceeds from these credit arrangements may be used for working capital and general corporate purposes as well as liquidity support for the Company's commercial paper program. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

The Company's commercial paper program is used to finance acquisition and construction costs related to electric generating facilities and for general corporate purposes. At December 31, 2008, there was no commercial paper outstanding. See Note 6 to the financial statements under "Bank Credit Arrangements" for additional information.

Management believes that the need for working capital can be adequately met by utilizing cash balances, commercial paper programs, and lines of credit.

Financing Activities

During 2008 and 2007, the Company did not issue any new long-term securities.

The issuance of all securities by the Company is generally subject to regulatory approval by the FERC. Additionally, with respect to the public offering of securities, the Company files registration statements with the Securities and Exchange Commission (SEC) under the Securities Act of 1933, as amended (1933 Act). The amounts of securities authorized by the FERC, as well as the amounts registered under the 1933 Act, are continuously monitored and appropriate filings are made to ensure flexibility in the capital markets.

Credit Rating Risk

The Company does not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit rating downgrade. There are certain contracts that could require collateral, but not accelerated payment, in the event of a credit rating change to BBB and Baa2, or BBB- and/or Baa3 or below. These contracts are for physical electricity purchases and sales, fuel purchases, fuel transportation and storage, and energy price risk management. At December 31, 2008, the maximum potential collateral requirements under these contracts at a BBB and Baa2 rating were approximately $9 million and at a BBB- and/or Baa3 rating were approximately $334 million. At December 31, 2008, the maximum potential collateral requirements under these contracts at a rating below BBB- and/or Baa3 were approximately $723 million. Included in these amounts are certain agreements that could require collateral in the event that one or more Power Pool participants has a credit rating change to below investment grade. Generally, collateral may be provided by a Southern Company guaranty, letter of credit, or cash. Additionally, any credit rating downgrade could impact the Company's ability to access capital markets, particularly the short-term debt market.

In addition, through the acquisition of Plant Rowan, the Company assumed a PPA with Duke Energy that could require collateral, but not accelerated payment, in the event of a downgrade to the Company's credit rating to below BBB- or Baa3. The amount of collateral required would depend upon actual losses, if any, resulting from a credit downgrade.

Market Price Risk

The Company is exposed to market risks, including changes in interest rates, certain energy-related commodity prices, and, occasionally, currency exchange rates. To manage the volatility attributable to these exposures, the Company takes advantage of natural offsets and enters into various derivative transactions for the remaining exposures pursuant to the Company's policies in areas such as counterparty exposure and hedging practices. Company policy is that derivatives are to be used primarily for hedging purposes. Derivative positions are monitored using techniques that include market valuation and sensitivity analysis.

At December 31, 2008, the Company had no variable long-term debt outstanding. Therefore, there would be no effect on annualized interest expense related to long-term debt if the Company sustained a 100 basis point change in interest rates. Since a significant portion of outstanding indebtedness bears interest at fixed rates, the Company is not aware of any facts or circumstances that would significantly affect such exposures in the near term. However, the impact on future financing costs cannot be determined at this time.

Because energy from the Company's facilities is primarily sold under long-term PPAs with tolling agreements and provisions shifting substantially all of the responsibility for fuel cost to the counterparties, the Company's exposure to market volatility in commodity fuel prices and prices of electricity is limited. However, the Company has been and may continue to be exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity.

The changes in fair value of energy-related derivative contracts were as follows at December 31:

	2008 Changes	2007 Changes
	Fair Value	
	(in millions)	
Contracts outstanding at the beginning of the period, assets (liabilities), net	$ 3.4	$ 1.9
Contracts realized or settled	1.4	(1.9)
Current period changes[a]	(1.4)	3.4
Contracts outstanding at the end of the period, assets (liabilities), net	$ 3.4	$ 3.4

(a) Current period changes also include the changes in fair value of new contracts entered into during the period, if any.

Although the change in the fair value positions of the energy-related derivative contracts for the year ended December 31, 2008 was immaterial, the underlying changes are attributable to both the volume and prices of power and natural gas as follows:

	December 31, 2008	December 31, 2007
Power (net sold)		
Megawatt hours (MWH) *(in millions)*	0.3	1.7
Weighted average contract cost per MWH above (below) market prices *(in dollars)*	$(2.29)	$1.76
Natural gas (net purchase)		
Billion cubic feet (Bcf)	1.9	3.8
Weighted average contract cost per British thermal unit (mmBtu) above (below) market prices *(in dollars)*	$(2.16)	$0.09

At December 31, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

	2008	2007
	(in millions)	
Cash flow hedges	$(0.8)	$0.1
Non-accounting hedges	4.2	3.3
Total fair value	$3.4	$3.4

Unrealized pre-tax gains and losses from energy-related derivative contracts recognized in income were not material for any year presented.

The maturities of the energy-related derivative contracts and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

	December 31, 2008 Fair Value Measurements			
	Total Fair Value	Maturity		
		Year 1	Years 2&3	Years 4&5
		(in millions)		
Level 1	$ -	$ -	$ -	$ -
Level 2	3.4	3.3	0.1	-
Level 3	-	-	-	-
Fair value of contracts outstanding at end of period	$ 3.4	$ 3.3	$ 0.1	$ -

As part of the adoption of FASB Statement No. 157, "Fair Value Measurements" to increase consistency and comparability in fair value measurements and related disclosures, the table above now uses the three-tier fair value hierarchy, as discussed in Note 8 to the financial statements, as opposed to the previously used descriptions "actively quoted," "external sources," and "models and other methods." The three-tier fair value hierarchy focuses on the fair value of the contract itself, whereas the previous descriptions focused on the source of the inputs. Because the Company uses over-the-counter contracts that are not exchange traded but are fair valued using prices which are actively quoted, the valuations of those contracts now appear in Level 2; previously they were shown as "actively quoted."

The Company is exposed to market-price risk in the event of nonperformance by counterparties to energy-related derivative contracts. The Company's practice is to enter into agreements with counterparties that have investment grade credit ratings by Standard & Poor's and Moody's or with counterparties who have posted collateral to cover potential credit exposure. Therefore, the Company does not anticipate market risk exposure from nonperformance by the counterparties. For additional information, see Notes 1 and 6 to the financial statements under "Financial Instruments."

Capital Requirements and Contractual Obligations

The capital program of the Company is currently estimated to be $748.9 million for 2009, $658.9 million for 2010, and $768.6 million for 2011. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements. Planned expenditures for plant acquisitions may vary due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital. On December 5, 2008, the Company announced plans to construct four combustion turbine units in North Carolina. See FUTURE EARNINGS POTENTIAL – "Construction Projects" herein for additional information.

Other funding requirements related to obligations associated with scheduled maturities of long-term debt, as well as the related interest, leases, derivative obligations, and other purchase commitments are as follows. See Notes 1, 6, and 7 to the financial statements for additional information.

Contractual Obligations

	2009	2010-2011	2012-2013	After 2013	Total
			(in millions)		
Long-term debt[a] –					
Principal	$ -	$ -	$575.0	$725.0	$1,300.0
Interest	74.3	148.6	112.6	344.4	679.9
Energy-related derivative obligations[b]	7.5	0.2	-	-	7.7
Operating leases	0.4	0.8	0.8	22.3	24.3
Purchase commitments[c] –					
Capital[d]	748.9	1,427.5	-	-	2,176.4
Natural gas[e]	40.6	269.0	101.0	316.2	726.8
Purchased power[f]	13.5	21.4	99.6	346.9	481.4
Long-term service agreements[g]	34.4	96.3	84.4	986.9	1,202.0
Total	$919.6	$1,963.8	$973.4	$2,741.7	$6,598.5

(a) All amounts are reflected based on final maturity dates. The Company plans to retire higher-cost securities and replace these obligations with lower-cost capital if market conditions permit.

(b) For additional information, see Notes 1 and 6 to the financial statements.

(c) The Company generally does not enter into non-cancelable commitments for other operations and maintenance expenditures. Total other operations and maintenance expenses for the last three years were $147.7 million, $135.0 million, and $95.3 million, respectively.

(d) The Company forecasts capital expenditures over a three-year period. Amounts represent estimates for potential plant acquisitions and new construction as well as ongoing capital improvements.

(e) Natural gas purchase commitments are based on various indices at the time of delivery. Amounts reflected have been estimated based on New York Mercantile Exchange future prices at December 31, 2008.

(f) Purchased power commitments of $71.5 million in 2012-2013 and $316.1 million after 2013 will be resold under a third party agreement to EnergyUnited. The purchases will be resold at cost.

(g) Long-term service agreements include price escalation based on inflation indices.

Cautionary Statement Regarding Forward-Looking Statements

The Company's 2008 Annual Report contains forward-looking statements. Forward-looking statements include, among other things, statements concerning environmental regulations and expenditures, financing activities, access to sources of capital, impacts of the adoption of new accounting rules, estimated sales and purchases under new power sale and purchase agreements, impacts of revisions to depreciation estimates, completion of construction projects, plans and estimated costs for new generation resources, and estimated construction and other expenditures. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential," or "continue" or the negative of these terms or other similar terminology. There are various factors that could cause actual results to differ materially from those suggested by the forward-looking statements; accordingly, there can be no assurance that such indicated results will be realized. These factors include:

- the impact of recent and future federal and state regulatory change, including legislative and regulatory initiatives regarding deregulation and restructuring of the electric utility industry, implementation of the Energy Policy Act of 2005, environmental laws including regulation of water quality and emissions of sulfur, nitrogen, mercury, carbon, soot, or particulate matter and other substances, and also changes in tax and other laws and regulations to which the Company is subject, as well as changes in application of existing laws and regulations;
- current and future litigation, regulatory investigations, proceedings, or inquiries, including FERC matters;
- the effects, extent, and timing of the entry of additional competition in the markets in which the Company operates;
- variations in demand for electricity, including those relating to weather, the general economy, population and business growth (and declines), and the effects of energy conservation measures;
- available sources and costs of fuels;
- effects of inflation;
- advances in technology;
- state and federal rate regulations;
- the ability to control costs and avoid cost overruns during the development and construction of facilities;
- internal restructuring or other restructuring options that may be pursued;
- potential business strategies, including acquisitions or dispositions of assets or businesses, which cannot be assured to be completed or beneficial to the Company;
- the ability of counterparties of the Company to make payments as and when due and to perform as required;
- the ability to obtain new short- and long-term contracts with wholesale customers;
- the direct or indirect effect on the Company's business resulting from terrorist incidents and the threat of terrorist incidents;
- interest rate fluctuations and financial market conditions and the results of financing efforts, including the Company's credit ratings;
- the ability of the Company to obtain additional generating capacity at competitive prices;
- catastrophic events such as fires, earthquakes, explosions, floods, hurricanes, droughts, pandemic health events such as an avian influenza, or other similar occurrences;
- the direct or indirect effects on the Company's business resulting from incidents similar to the August 2003 power outage in the Northeast;
- the effect of accounting pronouncements issued periodically by standard-setting bodies; and
- other factors discussed elsewhere herein and in other reports (including the Form 10-K) filed by the Company from time to time with the SEC.

The Company expressly disclaims any obligation to update any forward-looking statements.

CONSOLIDATED STATEMENTS OF INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Southern Power Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Revenues:			
Wholesale revenues --			
Non-affiliates	**$667,979**	$416,648	$279,384
Affiliates	**638,266**	547,229	491,762
Other revenues	**7,296**	8,137	5,902
Total operating revenues	**1,313,541**	972,014	777,048
Operating Expenses:			
Fuel	**424,800**	238,680	145,236
Purchased power --			
Non-affiliates	**132,222**	64,604	53,795
Affiliates	**195,743**	135,336	116,902
Other operations and maintenance	**147,711**	134,971	95,276
Gain on sale of property	**(6,015)**	-	-
Loss on IGCC project	**-**	17,619	-
Depreciation and amortization	**88,511**	73,985	65,959
Taxes other than income taxes	**17,700**	15,744	15,637
Total operating expenses	**1,000,672**	680,939	492,805
Operating Income	**312,869**	291,075	284,243
Other Income and (Expense):			
Interest expense, net of amounts capitalized	**(83,211)**	(79,175)	(80,154)
Other income (expense), net	**7,593**	3,285	2,191
Total other income and (expense)	**(75,618)**	(75,890)	(77,963)
Earnings Before Income Taxes	**237,251**	215,185	206,280
Income taxes	**92,892**	83,548	81,811
Net Income	**$144,359**	$131,637	$124,469

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2008, 2007, and 2006

Southern Power Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Operating Activities:			
Net income	**$144,359**	$131,637	$124,469
Adjustments to reconcile net income			
to net cash provided from operating activities --			
Depreciation and amortization	**102,783**	89,221	82,365
Deferred income taxes	**70,338**	31,665	33,150
Deferred revenues	**(704)**	(4,852)	2,248
Mark-to-market adjustments	**(925)**	(3,033)	(328)
Accumulated billings on construction contract	**85,619**	60,417	12,810
Accumulated costs on construction contract	**(110,096)**	(29,645)	(7,198)
Loss on IGCC project	**-**	17,619	-
Gain on sale of property	**(6,015)**	-	-
Other, net	**4,852**	7,874	2,484
Changes in certain current assets and liabilities --			
Receivables	**(11,156)**	(3,155)	38,479
Fossil fuel stock	**(2,640)**	(4,105)	(374)
Materials and supplies	**2,773**	(1,169)	(119)
Prepaid income taxes	**(21,338)**	-	-
Other current assets	**1,413**	(1,863)	(3,003)
Accounts payable	**10,451**	23,028	(34,163)
Accrued taxes	**(1,622)**	1,474	(8,522)
Accrued interest	**(252)**	319	687
Other current liabilities	**(3,575)**	-	-
Net cash provided from operating activities	**264,265**	315,432	242,985
Investing Activities:			
Property additions	**(49,964)**	(139,198)	(55,813)
Acquisition of plant facilities	**-**	-	(409,213)
Sale of property	**5,073**	-	-
Sale of property to affiliates	**-**	4,291	15,674
Change in construction payables	**(7,530)**	(1,960)	10,965
Payments pursuant to long-term service agreements	**(31,725)**	(44,471)	(35,678)
Other	**(1,624)**	(2,514)	-
Net cash used for investing activities	**(85,770)**	(183,852)	(474,065)
Financing Activities:			
Increase (decrease) in notes payable, net	**(49,748)**	(74,004)	13,060
Proceeds --			
Senior notes	**-**	-	200,000
Capital contributions	**3,642**	3,533	108,689
Redemptions --			
Other long-term debt	**-**	(1,209)	(200)
Payment of common stock dividends	**(94,500)**	(89,800)	(77,700)
Other	**-**	(24)	(10,471)
Net cash provided from (used for) financing activities	**(140,606)**	(161,504)	233,378
Net Change in Cash and Cash Equivalents	**37,889**	(29,924)	2,298
Cash and Cash Equivalents at Beginning of Year	**5**	29,929	27,631
Cash and Cash Equivalents at End of Year	**$37,894**	$ 5	$ 29,929
Supplemental Cash Flow Information:			
Cash paid during the period for --			
Interest (net of $7,075, $16,541 and $5,648 capitalized, respectively)	**$69,716**	$ 63,766	$ 65,206
Income taxes (net of refunds)	**47,611**	50,724	53,608

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS

At December 31, 2008 and 2007

Southern Power Company and Subsidiary Companies 2008 Annual Report

Assets	2008	2007
	(in thousands)	
Current Assets:		
Cash and cash equivalents	**$ 37,894**	$ 5
Receivables --		
Customer accounts receivable	**23,640**	19,100
Other accounts receivable	**2,162**	1,025
Affiliated companies	**33,401**	27,004
Fossil fuel stock, at average cost	**17,801**	15,160
Materials and supplies, at average cost	**26,527**	19,284
Prepaid service agreements - current	**26,304**	14,233
Prepaid income taxes	**18,066**	135
Other prepaid expenses	**2,755**	2,705
Assets from risk management activities	**10,799**	16,079
Other	**4,533**	4,226
Total current assets	**203,882**	118,956
Property, Plant, and Equipment:		
In service	**2,847,757**	2,534,507
Less accumulated provision for depreciation	**351,193**	280,962
	2,496,564	2,253,545
Construction work in progress	**8,775**	283,084
Total property, plant, and equipment	**2,505,339**	2,536,629
Deferred Charges and Other Assets:		
Prepaid long-term service agreements	**81,542**	87,058
Other--		
Affiliated	**3,827**	4,138
Other	**18,550**	21,993
Total deferred charges and other assets	**103,919**	113,189
Total Assets	**$2,813,140**	$2,768,774

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED BALANCE SHEETS

At December 31, 2008 and 2007

Southern Power Company and Subsidiary Companies 2008 Annual Report

Liabilities and Stockholder's Equity	2008	2007
	(in thousands)	
Current Liabilities:		
Notes payable	$ -	$ 49,748
Accounts payable --		
Affiliated	**62,732**	48,475
Other	**11,278**	20,322
Accrued taxes --		
Income taxes	**88**	392
Other	**2,343**	2,658
Accrued interest	**29,916**	30,168
Liabilities from risk management activities	**7,452**	12,639
Billings in excess of cost on construction contract	**11,907**	36,384
Other	**224**	9,523
Total current liabilities	**125,940**	210,309
Long-Term Debt:		
Senior notes --		
6.25% due 2012	**575,000**	575,000
4.875% due 2015	**525,000**	525,000
6.375% due 2036	**200,000**	200,000
Unamortized debt discount	**(2,647)**	(2,901)
Long-term debt	**1,297,353**	1,297,099
Deferred Credits and Other Liabilities:		
Accumulated deferred income taxes	**209,960**	138,123
Deferred capacity revenues -- Affiliated	**32,211**	34,801
Other --		
Affiliated	**6,667**	7,754
Other	**2,648**	2,801
Total deferred credits and other liabilities	**251,486**	183,479
Total Liabilities	**1,674,779**	1,690,887
Common Stockholder's Equity:		
Common stock, par value $0.01 per share --		
Authorized - 1,000,000 shares		
Outstanding - 1,000 shares	-	-
Paid-in capital	**862,109**	858,466
Retained earnings	**302,309**	253,131
Accumulated other comprehensive income (loss)	**(26,057)**	(33,710)
Total common stockholder's equity	**1,138,361**	1,077,887
Total Liabilities and Stockholder's Equity	**$2,813,140**	$2,768,774
Commitments and Contingent Matters (See notes)		

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY

For the Years Ended December 31, 2008, 2007, and 2006

Southern Power Company and Subsidiary Companies 2008 Annual Report

	Common Stock	Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
			(in thousands)		
Balance at December 31, 2005	$ -	$746,243	$164,525	$(44,425)	$ 866,343
Net income	-	-	124,469	-	124,469
Capital contributions from parent company	-	108,689	-	-	108,689
Other comprehensive income (loss)	-	-	-	3,701	3,701
Cash dividends on common stock	-	-	(77,700)	-	(77,700)
Other	-	1	1	-	2
Balance at December 31, 2006	-	854,933	211,295	(40,724)	1,025,504
Net income	-	-	131,637	-	131,637
Capital contributions from parent company	-	3,533	-	-	3,533
Other comprehensive income (loss)	-	-	-	7,014	7,014
Cash dividends on common stock	-	-	(89,800)	-	(89,800)
Other	-	-	(1)	-	(1)
Balance at December 31, 2007	-	**858,466**	**253,131**	**(33,710)**	**1,077,887**
Net income	-	-	**144,359**	-	**144,359**
Capital contributions from parent company	-	**3,642**	-	-	**3,642**
Other comprehensive income (loss)	-	-	-	**7,653**	**7,653**
Cash dividends on common stock	-	-	**(94,500)**	-	**(94,500)**
Other	-	**1**	**(681)**	-	**(680)**
Balance at December 31, 2008	$ -	**$862,109**	**$302,309**	**$(26,057)**	**$1,138,361**

The accompanying notes are an integral part of these financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the Years Ended December 31, 2008, 2007, and 2006

Southern Power Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006
		(in thousands)	
Net income	**$144,359**	$131,637	$124,469
Other comprehensive income (loss):			
Qualifying hedges:			
Changes in fair value, net of tax of $351, $(558), and $(2,801), respectively	**529**	(842)	(4,263)
Reclassification adjustment for amounts included in net income, net of tax of $4,554, $5,244, and $3,992, respectively	**7,124**	7,856	7,964
Total other comprehensive income (loss)	**7,653**	7,014	3,701
Comprehensive Income	**$152,012**	$138,651	$128,170

The accompanying notes are an integral part of these financial statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Southern Power Company (the Company) is a wholly-owned subsidiary of Southern Company, which is also the parent company of four traditional operating companies, Southern Company Services, Inc. (SCS), Southern Communications Services, Inc. (SouthernLINC Wireless), Southern Company Holdings, Inc. (Southern Holdings), Southern Nuclear Operating Company, Inc. (Southern Nuclear), and other direct and indirect subsidiaries. The traditional operating companies, Alabama Power Company (APC), Georgia Power Company (GPC), Gulf Power Company (Gulf Power), and Mississippi Power Company, are vertically integrated utilities providing electric service in four Southeastern states. The Company constructs, acquires, owns, and manages generation assets and sells electricity at market-based rates in the wholesale market. SCS, the system service company, provides, at cost, specialized services to Southern Company and its subsidiary companies. SouthernLINC Wireless provides digital wireless communications for use by Southern Company and its subsidiary companies and also markets these services to the public and provides fiber cable services within the Southeast. Southern Holdings is an intermediate holding company subsidiary for Southern Company's investments in leveraged leases and various other energy-related businesses. Southern Nuclear operates and provides services to Southern Company's nuclear power plants.

The Company is subject to regulation by the Federal Energy Regulatory Commission (FERC). The Company follows accounting principles generally accepted in the United States. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires the use of estimates, and the actual results may differ from those estimates.

The financial statements include the accounts of the Company and its wholly-owned subsidiaries, Southern Company – Florida LLC, Oleander Power Project, LP (Oleander), DeSoto County Generating Company, LLC (DeSoto), and Southern Power Company – Orlando Gasification LLC (SPC-OG), which own, operate, and maintain the Company's ownership interests in Plant Stanton Unit A, Plant Oleander, Plant DeSoto, and construct the combined cycle for the Orlando Utilities Commission (OUC), respectively. See Note 2 under "DeSoto and Rowan Acquisitions" and "Oleander Acquisition." All intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications

Certain prior years' data presented in the financial statements have been reclassified to conform to the current year presentation. These reclassifications had no effect on total assets, net income, or cash flows. The consolidated statements of income for the periods presented have been modified within the operating expenses section to combine the line items "Other operations" and "Maintenance" into a single line item entitled "Other operations and maintenance." The consolidated statements of cash flows were modified to present a separate line item within the investing section for "Payments pursuant to long-term service agreements" previously included in "Property additions." The balance sheet at December 31, 2007 was modified to reflect the amount of "Prepaid income taxes" previously included in "Other prepaid expenses."

Affiliate Transactions

The Company has an agreement with SCS under which the following services are rendered to the Company at amounts in compliance with FERC regulation: general and design engineering, purchasing, accounting and statistical analysis, finance and treasury, tax, information resources, marketing, auditing, insurance and pension administration, human resources, systems and procedures, digital wireless communications, labor, and other services with respect to business and operations and power pool transactions. Because the Company has no employees, all employee-related charges are rendered at amounts in compliance with FERC regulation under agreements with SCS. Costs for these services from SCS amounted to approximately $207.4 million in 2008, $125.4 million in 2007, and $77.8 million in 2006. Approximately $87.9 million in 2008, $74.1 million in 2007, and $59.7 million in 2006 were operations and maintenance expenses; the remainder was recorded to construction work in progress, other assets, and billings in excess of cost on construction contract. Cost allocation methodologies used by SCS were approved by the Securities and Exchange Commission prior to the repeal of the Public Utility Holding Company Act of 1935, as amended, and management believes they are reasonable. The FERC permits services to be rendered at cost by system service companies.

In 2003, the Company entered into agreements with APC and GPC under which APC and GPC operated and maintained Plants Dahlberg, Wansley, Franklin, and Harris. GPC also supplied various services for other plants. In August 2007, those agreements were terminated and replaced with service agreements under which APC and GPC provide specifically requested services to the Company. These services are billed at amounts in compliance with FERC regulation on a monthly basis and are recorded as

operations and maintenance expenses in the consolidated statements of income. For the periods ended December 31, 2008, 2007, and 2006, billings under these agreements totaled approximately $2.9 million, $9.2 million, and $7.6 million, respectively.

Total billings for all purchased power agreements (PPAs) in effect with affiliates totaled $539.6 million, $505.2 million, and $467.9 million in 2008, 2007, and 2006, respectively. Included in these billings were $32.2 million, $34.8 million, and $36.3 million of "Deferred capacity revenues – affiliated" recorded on the balance sheets at December 31, 2008, December 31, 2007, and December 31, 2006, respectively. The Company and the traditional operating companies may jointly enter into various types of wholesale energy, natural gas, and certain other contracts, either directly or through SCS as agent. Each participating company may be jointly and severally liable for the obligations incurred under these agreements.

The Company and the traditional operating companies generally settle amounts related to the above transactions on a monthly basis in the month following the performance of such services or the purchase or sale of electricity.

In 2008, Gulf Power and APC sold turbine rotor assemblies to the Company for $9.4 million and $6.3 million, respectively. Additionally, the Company sold a turbine rotor assembly to APC for $8.2 million and sold a compressor assembly to GPC for $3.9 million. No gain or loss was recognized in the Company's consolidated statements of income. These affiliate transactions were made in accordance with FERC and state Public Service Commission (PSC) rules and guidelines.

In 2007, the Company sold plots of land in Prattville, Alabama and Chilton County, Alabama to APC. The total sales price was $4.3 million and is recorded in "Sale of property to affiliates" on the statements of cash flows. In addition, the Company sold a turbine rotor to Gulf Power for $7.9 million. No gain or loss was recognized in the Company's consolidated statements of income. These affiliate transactions were made in accordance with FERC and state PSC rules and guidelines.

In 2006, the Company sold its membership interests in Cherokee Falls Development of South Carolina LLC to Southern Company's nuclear development affiliate. The sales price was $15.7 million and is recorded in "Sale of property to affiliates" on the statement of cash flows. No gain or loss was recognized in the Company's consolidated statements of income.

Revenues

Capacity is sold at rates specified under contractual terms and is recognized at the lesser of the levelized amount or the amount billable under the contract over the respective contract periods. Energy is generally sold at market-based rates and the associated revenue is recognized as the energy is delivered. Transmission revenues and other fees are recognized as incurred as other operating revenue. Revenues are recorded on a gross basis for all full requirements PPAs. See "Financial Instruments" for additional information.

Significant portions of the Company's revenues have been derived from certain customers pursuant to PPAs. For the year ended December 31, 2008, GPC accounted for 36.5% of total revenues, Sawnee Electric Membership Corporation accounted for 6.1% of total revenues, and Flint Electric Membership Corporation accounted for 5.3% of total revenues. For the year ended December 31, 2007, GPC accounted for 45.6% of total revenues, APC accounted for 6.9% of total revenues, and Sawnee Electric Membership Corporation accounted for 5.5% of total revenues. For the year ended December 31, 2006, GPC accounted for 52.7% of total revenues, APC accounted for 8.2% of total revenues, and Flint Electric Membership Corporation accounted for 4.6% of total revenues.

The Company has a long-term contract for engineering, procurement, and construction services to build a combined cycle unit for OUC. Construction activities commenced in 2006 and are expected to be complete by the end of 2009. Revenue and costs are recognized using the percentage-of-completion method. The Company utilizes the cost-to-cost approach as this method is less subjective than relying on assessments of physical progress. The percentage of completion represents the percentage of the total costs incurred to the estimated total cost of the contract. Revenues and costs are recognized by applying this percentage to the total revenues and estimated costs of the contract.

Fuel Costs

Fuel costs are expensed as the fuel is consumed.

Income and Other Taxes

The Company uses the liability method of accounting for deferred income taxes and provides deferred income taxes for all significant income tax temporary differences. In accordance with Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" (FIN 48), the Company recognizes tax positions that are "more likely than not" of being sustained upon examination by the appropriate taxing authorities. See Note 5 under "Unrecognized Tax Benefits" for additional information.

Property, Plant, and Equipment

The Company's depreciable property, plant, and equipment consist entirely of generation assets.

Property, plant, and equipment is stated at original cost. Original cost includes materials, direct labor incurred by contractors and affiliated companies, minor items of property, and interest capitalized. Interest is capitalized on qualifying projects during the development and construction period. The cost to replace significant items of property defined as retirement units is capitalized. The cost of maintenance, repairs, and replacement of minor items of property is charged to maintenance expense as incurred.

Depreciation

Depreciation of the original cost of assets is computed under the straight-line method and applies a composite depreciation rate based on the assets' estimated useful lives determined by the Company. The primary assets in property, plant, and equipment are power plants, all of which have an estimated composite depreciable life ranging from 29-37 years. These lives reflect a composite of the significant components (retirement units) that make up the plants. The Company reviews its estimated useful lives and salvage values on an ongoing basis. The results of these reviews could result in changes which could have a material impact on net income in the near term.

A depreciation study was completed and the applicable remaining plant lives and associated depreciation rates were revised in January 2008. This change in estimate was due to revised useful life assumptions for certain components of plant in service. Depreciation rates by generating facility changed from a range of 2.8% to 3.8% to an adjusted range of 1.8% to 4.1%. These changes increased depreciation and reduced income from continuing operations and net income by $4.6 million and $2.8 million, respectively, for 2008.

When property subject to composite depreciation is retired or otherwise disposed of in the normal course of business, its cost is charged to accumulated depreciation. For other property dispositions, the applicable cost and accumulated depreciation is removed from the accounts and a gain or loss is recognized.

Asset Retirement Obligations and Other Costs of Removal

The present value of the ultimate costs for an asset's future retirement is recorded in the period in which the liability is incurred. The costs are capitalized as part of the related long-lived asset and depreciated over the asset's useful life.

At December 31, 2008, the Company had no material liability for asset retirement obligations.

Interest Capitalized

Interest related to the construction of new facilities is capitalized in accordance with standard interest capitalization requirements per FASB Statement No. 34, "Capitalization of Interest Cost."

Impairment of Long-Lived Assets and Intangibles

The Company evaluates long-lived assets for impairment when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. The determination of whether impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, as compared with the carrying value of the assets. If an impairment has occurred, the

amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. For assets identified as held for sale, the carrying value is compared to the estimated fair value less the cost to sell in order to determine if an impairment loss is required. Until the assets are disposed of, their estimated fair value is re-evaluated when circumstances or events change.

Deferred Project Development Costs

The Company capitalizes project development costs once it is determined that it is probable that a specific site will be acquired and a power plant constructed. These costs include professional services, permits, and other costs directly related to the construction of a new project. These costs are generally transferred to construction work in progress upon commencement of construction. The total deferred project development costs were $8.9 million at December 31, 2008, $8.4 million at December 31, 2007, and $1.3 million at December 31, 2006.

Cash and Cash Equivalents

For purposes of the financial statements, temporary cash investments are considered cash equivalents. Temporary cash investments are securities with original maturities of 90 days or less.

Materials and Supplies

Generally, materials and supplies include the average costs of generating plant materials. Materials are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, at weighted average cost when installed.

Fuel Inventory

Fuel inventory includes the cost of oil and emission allowances. The Company maintains minimal oil levels for use at Plant Dahlberg, Plant Oleander, Plant DeSoto, and Plant Rowan. Inventory is maintained using the weighted average cost method. Fuel inventory and emissions allowances are recorded at actual cost when purchased and then expensed at weighted average cost as used.

Financial Instruments

The Company uses derivative financial instruments to limit exposure to fluctuations in interest rates, the prices of certain fuel purchases, and electricity purchases and sales. All derivative financial instruments are recognized as either assets or liabilities (categorized in "Other" or shown separately as "Risk Management Activities") and are measured at fair value. See Note 8 for additional information. Substantially all of the Company's bulk energy purchases and sales contracts that meet the definition of a derivative are exempt from fair value accounting requirements and are accounted for under the accrual method. Other derivative contracts qualify as cash flow hedges of anticipated transactions. This results in the deferral of related gains and losses in other comprehensive income until the hedged transactions occur. Any ineffectiveness is recognized currently in net income. Other derivative contracts are marked to market through current period income and are recorded in the financial statement line item where they will eventually settle. See Note 6 under "Financial Instruments" for additional information.

The Company does not offset fair value amounts recognized for multiple derivative instruments executed with the same counterparty under a master netting arrangement. Additionally, the Company had no outstanding collateral repayment obligations or rights to reclaim collateral arising from derivative instruments recognized at December 31, 2008.

The Company is exposed to losses related to financial instruments in the event of counterparties' nonperformance. The Company has established controls to determine and monitor the creditworthiness of counterparties in order to mitigate the Company's exposure to counterparty credit risk.

The Company's financial instruments for which the carrying amounts did not equal fair value at December 31 were as follows:

	Carrying Amount	Fair Value
	(in millions)	
Long-term debt:		
2008	**$ 1,297**	**$ 1,270**
2007	1,297	1,298

The fair values were based on either closing market prices (Level 1) or closing prices of comparable instruments (Level 2). See Note 8 for all other items recognized at fair value in the financial statements.

Comprehensive Income

The objective of comprehensive income is to report a measure of all changes in common stock equity of an enterprise that result from transactions and other economic events of the period other than transactions with owners. Comprehensive income consists of net income and changes in the fair value of qualifying cash flow hedges, less income taxes and reclassifications of amounts included in net income.

Other Income (Expense)

Other income (expense) includes non-operating revenues and expenses which are recognized when earned. In 2008, the Company received a fee of $6.4 million for participating in an asset auction. The Company was not the successful bidder in the asset auction.

2. ACQUISITIONS

Oleander Acquisition

In June 2005, the Company acquired all of the outstanding general and limited partnership interests of Oleander from subsidiaries of Constellation Energy Group, Inc. The results of Oleander's operations have been included in the Company's consolidated financial statements since that date. The Company's acquisition of the general and limited partnership interests in Oleander was pursuant to a Purchase and Sale Agreement dated April 8, 2005, for an aggregate total cost of approximately $218.1 million, including approximately $11.9 million of working capital and other adjustments. At the time of acquisition, Plant Oleander, a dual-fueled generating plant in Brevard County, Florida, had a nameplate capacity of 628 megawatts (MW). The Oleander acquisition was in accordance with the Company's overall growth strategy.

Subsequent to the acquisition, the Company completed construction of Plant Oleander Unit 5 in December 2007. This unit is a combustion turbine with a nameplate capacity of 163 MW and is contracted to provide annual capacity for a PPA with the Florida Municipal Power Agency from 2007 through 2027.

Desoto and Rowan Acquisitions

Effective June 1, 2006, the Company acquired all of the outstanding membership interests of DeSoto County Generating Company, LLC (DeSoto) from a subsidiary of Progress Energy, Inc. The results of DeSoto's operations have been included in the Company's consolidated financial statements since that date. The Company's acquisition of the membership interest in DeSoto was pursuant to an agreement dated May 8, 2006, for an aggregate total cost of $79.7 million. DeSoto owns a dual-fired generating plant near Arcadia, Florida with a nameplate capacity of 344 MW. The DeSoto acquisition was in accordance with the Company's overall growth strategy.

Effective September 1, 2006, the Company acquired all of the outstanding membership interests of Rowan County Power, LLC (Rowan) from a subsidiary of Progress Energy, Inc. Rowan was merged into the Company, and the results of Rowan's operations have been included in the Company's consolidated financial statements since that date. The Company's acquisition of the membership interests in Rowan was pursuant to an agreement dated May 8, 2006 for an aggregate total cost of $329.5 million. Through the Rowan acquisition, the Company owns a dual-fired generating plant near Salisbury, North Carolina with a nameplate capacity of 986 MW. The Rowan acquisition was in accordance with the Company's overall growth strategy.

The pro forma data of the Company below is unaudited and gives effect to the DeSoto and Rowan plant acquisitions as if they had occurred at January 1, 2006. The unaudited pro forma financial information is not intended to represent or be indicative of the consolidated results of operations or financial condition of the Company that would have been reported had the acquisitions been completed as of the dates presented nor should be taken as representative of any future consolidated results of operations or financial condition of the Company.

For the Twelve Months Ended December 31, 2006	
	(in thousands)
Pro forma revenues	$795,701
Pro forma net income	118,703

3. CONTINGENCIES AND REGULATORY MATTERS

General Litigation Matters

The Company is subject to certain claims and legal actions arising in the ordinary course of business. In addition, the Company's business activities are subject to extensive governmental regulation related to public health and the environment. Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements such as opacity and air and water quality standards, has increased generally throughout the United States. In particular, personal injury claims for damages caused by alleged exposure to hazardous materials have become more frequent. The ultimate outcome of such pending or potential litigation against the Company and its subsidiaries cannot be predicted at this time; however, for current proceedings not specifically reported herein, management does not anticipate that the liabilities, if any, arising from such current proceedings would have a material adverse effect on the Company's financial statements.

FERC Matters

Market-Based Rate Authority

The Company has authorization from the FERC to sell power to non-affiliates, including short-term opportunity sales, at market-based prices. Specific FERC approval must be obtained with respect to a market-based contract with an affiliate.

In December 2004, the FERC initiated a proceeding to assess Southern Company's generation dominance within its retail service territory. The ability to charge market-based rates in other markets is not an issue in the proceeding. Any new market-based rate sales by the Company in Southern Company's retail service territory entered into during a 15-month refund period that ended in May 2006 could be subject to refund to a cost-based rate level.

In November 2007, the presiding administrative law judge issued an initial decision regarding the methodology to be used in the generation dominance tests. The proceedings are ongoing. The ultimate outcome of this generation dominance proceeding cannot now be determined, but an adverse decision by the FERC in a final order could require the Company to charge cost-based rates for certain wholesale sales in the Southern Company retail service territory, which may be lower than negotiated market-based rates, and could also result in total refunds of up to $0.7 million, plus interest. The Company believes that there is no meritorious basis for an adverse decision in this proceeding and is vigorously defending itself in this matter.

In June 2007, the FERC issued its final rule in Order No. 697 regarding market-based rate authority. The FERC generally retained its current market-based rate standards. Responding to a number of requests for rehearing, the FERC issued Order No. 697-A on April 21, 2008 and Order No. 697-B on December 12, 2008. These orders largely affirmed its prior revision and codification of the regulations governing market-based rates for public utilities. In accordance with the orders, Southern Company submitted to the FERC an updated market power analysis on September 2, 2008 related to its continued market-based rate authority. The ultimate outcome of this matter cannot now be determined.

On October 17, 2008, Southern Company filed with the FERC a revised market-based rate (MBR) tariff and a new cost-based rate (CBR) tariff. The revised MBR tariff provides for a "must offer" energy auction whereby Southern Company offers all of its available energy for sale in a day-ahead auction and an hour-ahead auction with reserve prices not to exceed the CBR tariff price, after considering Southern Company's native load requirements, reliability obligations, and sales commitments to third parties. All sales under the energy auction would be at market clearing prices established under the auction rules. The new CBR tariff provides for a cost-based price for wholesale sales of less than a year. On December 18, 2008, the FERC issued an order conditionally accepting the MBR tariff subject to certain revisions to the auction proposal. On January 21, 2009, Southern Company made a compliance filing that accepted all the conditions of the MBR tariff order. When this order becomes final, Southern Company will have 30 days to implement the wholesale auction. On December 31, 2008, the FERC issued an order conditionally accepting the CBR tariff subject to providing additional information concerning one aspect of the tariff. On January 30, 2009, Southern Company filed a response addressing the FERC inquiry to the CBR tariff order. Implementation of the energy auction in accordance with the MBR tariff order is expected to adequately mitigate going forward any presumption of market power that Southern Company may have in the Southern Company retail service territory. The timing of when the FERC may issue the final orders on the MBR and CBR tariffs and the ultimate outcome of these matters cannot be determined at this time.

Intercompany Interchange Contract

The majority of the Company's generation fleet is operated under the Intercompany Interchange Contract (IIC), as approved by the FERC. In May 2005, the FERC initiated a new proceeding to examine (1) the provisions of the IIC among the traditional operating companies, the Company, and SCS, as agent, under the terms of which the Southern Pool is operated, (2) whether any parties to the IIC have violated the FERC's standards of conduct applicable to utility companies that are transmission providers, and (3) whether Southern Company's code of conduct defining the Company as a "system company" rather than a "marketing affiliate" is just and reasonable. In connection with the formation of the Company, the FERC authorized the Company's inclusion in the IIC in 2000. The FERC also previously approved Southern Company's code of conduct.

In October 2006, the FERC issued an order accepting a settlement resolving the proceeding subject to Southern Company's agreement to accept certain modifications to the settlement's terms and Southern Company notified the FERC that it accepted the modifications. The modifications largely involve functional separation and information restrictions related to marketing activities conducted on behalf of the Company. In November 2006, Southern Company filed with the FERC a compliance plan in connection with the order. In April 2007, the FERC approved, with certain modifications, the plan submitted by Southern Company. In November 2007, Southern Company notified the FERC that the plan had been implemented. On December 12, 2008 the FERC division of audits issued its final audit report pertaining to compliance implementation and related matters. No comments challenging the audit report's findings were submitted. A decision is now pending from the FERC. The Company's cost of implementing the plan, including the modifications, is approximately $7.0 million annually. The ultimate outcome of this matter cannot be determined at this time.

Carbon Dioxide Litigation

On February 26, 2008, the Native Village of Kivalina and the City of Kivalina filed a suit in the U.S. District Court for the Northern District of California against several electric utilities (including Southern Company), several oil companies, and a coal company. The plaintiffs are the governing bodies of an Inupiat village in Alaska. The plaintiffs contend that the village is being destroyed by erosion allegedly caused by global warming that the plaintiffs attribute to emissions of greenhouse gases by the defendants. The plaintiffs assert claims for public and private nuisance and contend that the defendants have acted in concert and are therefore jointly and severally liable for the plaintiffs' damages. The suit seeks damages for lost property values and for the cost of relocating the village, which is alleged to be $95 million to $400 million. On June 30, 2008, all defendants filed motions to dismiss this case. Southern Company believes that these claims are without merit and notes that the complaint cites no statutory or regulatory basis for the claims. The ultimate outcome of this matter cannot be determined at this time.

4. JOINT OWNERSHIP AGREEMENTS

Plant Stanton A

The Company is a 65% owner of Plant Stanton A, a combined-cycle project with a nameplate capacity of 630 MW. The unit is co-owned by OUC (28%), Florida Municipal Power Agency (3.5%), and Kissimmee Utility Authority (3.5%). The Company has a service agreement with SCS whereby SCS is responsible for the operation and maintenance of Plant Stanton A. As of December 31, 2008, $150.9 million was recorded in plant in service with associated accumulated depreciation of $14.1 million. These amounts represent the Company's share of the total plant assets and each owner must provide its own financing. The Company's proportionate share of Plant Stanton A's operating expense is included in the corresponding operating expenses in the statements of income.

Integrated Coal Gasification Combined Cycle (IGCC)

In December 2005, the Company and OUC executed definitive agreements for development of a 285-MW IGCC project in Orlando, Florida. The definitive agreements provided that the Company would own at least 65% of the gasifier portion of the IGCC project. OUC would own the remainder of the gasifier portion and 100% of the combined cycle portion of the IGCC project. The Company signed cooperative agreements with the U.S. Department of Energy (DOE) that provided up to $293.75 million in grant funding for the gasification portion of this project. The IGCC project was expected to begin commercial operation in 2010. Due to continuing uncertainty surrounding potential state regulations relating to greenhouse gas emissions, the Company and OUC mutually agreed to terminate the construction of the gasifier portion of the IGCC project in November 2007. The Company has continued construction of the gas-fired combined cycle generating facility for OUC. The Company recorded a loss in the fourth quarter 2007 of approximately $17.6 million related to cancellation of the gasifier portion of the IGCC project. This amount is net of reimbursements from OUC and the DOE. This loss consists of the write-off of construction costs of $14.0 million and an accrual for termination costs of $3.6 million. All termination costs were paid in 2008. As part of the termination agreement with OUC, the Company agreed to sell a tract of land in Orange County, Florida to OUC. The Company recorded a gain of $6 million on this sale in 2008.

5. INCOME TAXES

Southern Company files a consolidated federal income tax return and combined tax returns for the State of Georgia, the State of Alabama, and the State of Mississippi. Under a joint consolidated income tax allocation agreement, each subsidiary's current and deferred tax expense is computed on a stand-alone basis, and no subsidiary is allocated more expense than would be paid if it filed a separate income tax return. In accordance with Internal Revenue Service (IRS) regulations, each company is jointly and severally liable for the tax liability.

Current and Deferred Income Taxes

Details of income tax provisions are as follows:

	2008	2007	2006
		(in thousands)	
Federal –			
Current	$ 18,948	$42,841	$39,653
Deferred	57,194	26,808	26,915
	76,142	69,649	66,568
State –			
Current	3,605	9,042	9,008
Deferred	13,145	4,857	6,235
	16,750	13,899	15,243
Total	$ 92,892	$83,548	$81,811

The tax effects of temporary differences between the carrying amounts of assets and liabilities in the financial statements and their respective tax bases, which give rise to deferred tax assets and liabilities, are as follows:

	2008	2007
		(in thousands)
Deferred tax liabilities–		
Accelerated depreciation and other property basis differences	**$ 274,098**	$ 209,036
Book/tax basis difference on asset transfers	**4,312**	4,564
Other	**2,493**	-
Total	**280,903**	213,600
Deferred tax assets–		
Federal effect of state deferred taxes	**12,910**	8,459
Book/tax basis differences on asset transfers	**7,962**	9,027
Other comprehensive loss on interest rate swaps	**32,386**	33,966
Levelized capacity revenues	**14,279**	14,166
Other	**-**	9,859
Total	**67,537**	75,477
Total deferred tax liabilities, net	**213,366**	138,123
Portion included in prepaid income taxes	**(3,406)**	-
Accumulated deferred income taxes in the balance sheets	**$ 209,960**	$ 138,123

Deferred tax liabilities are the result of property related timing differences. The transfer of the Plant McIntosh construction project to GPC in 2004 resulted in a deferred gain for federal income tax purposes. GPC is reimbursing the Company for the related tax liability balance of $4.3 million. Of this total, $0.5 million is included in the balance sheets in "Receivables – Affiliated companies" and the remainder is included in "Deferred Charges and Other Assets: Other – Affiliated."

Deferred tax assets consist primarily of timing differences related to the recognition of capacity revenues, and the deferred loss on interest rate swaps reflected in other comprehensive income. The transfer of Plants Dahlberg, Wansley, and Franklin to the Company from GPC in 2001 also resulted in a deferred gain for federal income tax purposes. The Company will reimburse GPC for the related tax asset of $8.0 million. Of this total, $1.3 million is included in the balance sheets in "Accounts payable – Affiliated" and the remainder is included in "Deferred Credits and Other Liabilities: Other – Affiliated."

Effective Tax Rate

A reconciliation of the federal statutory tax rate to the effective income tax rate is as follows:

	2008	2007	2006
Federal statutory rate	35.0%	35.0%	35.0%
State income tax, net of federal deduction	4.6	4.2	4.8
Other	(0.4)	(0.4)	(0.1)
Effective income tax rate	39.2%	38.8%	39.7%

The American Jobs Creation Act of 2004 created a tax deduction for a portion of income attributable to U.S. production activities as defined in the Internal Revenue Code of 1986, as amended, Section 199 (production activities deduction). The deduction is equal to a stated percentage of qualified production activities net income. The percentage is phased in over the years 2005 through 2010 with a 3% rate applicable to the years 2005 and 2006, a 6% rate applicable for years 2007 through 2009, and a 9% rate thereafter. This increase from 3% in 2006 to 6% in 2007 was one of several factors that increased the Company's 2007 deduction by $1.2 million over the 2006 deduction. The resulting additional tax benefit was $0.4 million. The IRS has not clearly defined a methodology for calculating this deduction. However, Southern Company has agreed with the IRS on a calculation methodology and signed a closing agreement on December 11, 2008. Therefore, the Company reversed the unrecognized tax benefit and adjusted the deduction for all previous years to conform to the agreement which resulted in a decrease in the 2008 deduction when compared to the 2007 deduction. The net impact of the reversal of the unrecognized tax benefits combined with the application of the new methodology had no material effect on the Company's financial statements.

Unrecognized Tax Benefits

FIN 48 requires companies to determine whether it is "more likely than not" that a tax position will be sustained upon examination by the appropriate taxing authorities before any part of the benefit can be recorded in the financial statements. It also provides guidance on the recognition, measurement, and classification of income tax uncertainties, along with any related interest and penalties. For 2008, the total amount of unrecognized tax benefits decreased $0.9 million, resulting in a balance of $0.5 million as of December 31, 2008.

Changes during the year in unrecognized tax benefits were as follows:

	2008	2007
	(in millions)	
Unrecognized tax benefits at beginning of year	**$ 1.4**	$ 0.2
Tax positions from current periods	**0.3**	0.4
Tax positions from prior periods	**0.1**	0.8
Reductions due to settlements	**(1.3)**	-
Reductions due to expired statute of limitations	**-**	-
Balance at end of year	**$ 0.5**	$ 1.4

The reduction due to settlements relates to the agreement with the IRS regarding the production activities deduction methodology. See "Effective Tax Rate" above for additional information.

Impact on the Company's effective tax rate, if recognized, is as follows:

	2008	2007	Change
		(in millions)	
Tax positions impacting the effective tax rate	**$ 0.5**	$ 1.4	$ 0.9
Tax positions not impacting the effective tax rate	**-**	-	-
Balance of unrecognized tax benefits	**$ 0.5**	$ 1.4	$ 0.9

Accrued interest for unrecognized tax benefits:

	2008	2007
	(in millions)	
Interest accrued at beginning of year	**$ 0.1**	$ -
Interest reclassified due to settlements	**(0.1)**	-
Interest accrued during the year	-	0.1
Balance at end of year	**$ -**	$ 0.1

The Company classifies interest on tax uncertainties as interest expense. The Company did not accrue any penalties on uncertain tax positions.

The IRS has audited and closed all tax returns prior to 2004. The audits for the state returns have either been concluded, or the statute of limitations has expired, for years prior to 2002.

It is reasonably possible that the amount of the unrecognized benefit with respect to a majority of the Company's unrecognized tax positions will increase or decrease within the next 12 months. At this time, an estimate of the range of reasonably possible outcomes cannot be determined.

6. FINANCING

Senior Notes

In 2008 and 2007, the Company did not issue any long-term debt securities. Long-term debt outstanding was $1.3 billion at December 31, 2008 and 2007. The Company issued $200 million aggregate principal amount of unsecured 30-year senior notes in 2006. The proceeds of the issuance were used to repay a portion of the Company's short-term indebtedness and for other general corporate purposes, including the Company's construction program.

Bank Credit Arrangements

The Company has a $400 million unsecured syndicated revolving credit facility (Facility) expiring in July 2012. The purpose of the Facility is to provide liquidity support to the Company's commercial paper program and for other general corporate purposes. There were no borrowings outstanding under the Facility at December 31, 2008. Outstanding borrowings under the Facility at December 31, 2007 were $13.0 million.

The Company is required to pay a commitment fee on the unused balance of the Facility. This fee is less than $^1/_8$ of 1%. In 2008 and 2007, the Company incurred approximately $0.4 million and $0.4 million, respectively, in expenses from commitment fees under the Facility.

During 2008, the Company borrowed under the Facility and also borrowed under uncommitted facilities. For the year ended December 31, 2008, the peak balance outstanding was $95 million. The average amount outstanding was $13.3 million in 2008. The average annual interest rate was 3.2%. At December 31, 2008, there were no outstanding balances.

The Facility contains a covenant that limits the ratio of debt to capitalization (each as defined in the Facility) to a maximum of 65%. The Facility also contains a cross default provision that would be triggered if the Company defaulted on other indebtedness above a specified threshold. As of December 31, 2008, the Company was in compliance with all such covenants.

The Company has established a commercial paper program. For the year ended December 31, 2008, the peak commercial paper balance outstanding was $103.2 million. The average amount outstanding was $38.2 million in 2008. The average annual interest rate was 3.5%. At December 31, 2008, the commercial paper program had no outstanding balances. The outstanding balance at December 31, 2007 was $36.7 million at a weighted average interest rate of 5.7%.

Dividend Restrictions

The Company can only pay dividends to Southern Company out of retained earnings or paid-in-capital.

The Facility and the indenture related to certain series of the Company's senior notes also contain certain limitations on the payment of common stock dividends. No dividends may be paid unless, as of the end of any calendar quarter, the Company's projected cash flows from fixed priced capacity PPAs are at least 80% of total projected cash flows for the next 12 months or the Company's debt to capitalization ratio is no greater than 60%. At December 31, 2008, the Company was in compliance with these ratios and had no other restrictions on its ability to pay dividends.

Financial Instruments

The Company enters into energy-related derivatives to hedge exposures to electricity, gas, and other fuel price changes. The Company's exposure to market volatility in commodity fuel prices and prices of electricity is limited because its long-term sales contracts shift substantially all fuel cost responsibility to the purchaser. However, the Company has been exposed to market volatility in energy-related commodity prices as a result of sales of uncontracted generating capacity. At December 31, 2008 and 2007, the net fair value of energy-related derivative contracts by hedge designation was reflected in the financial statements as assets/(liabilities) as follows:

	2008	2007
	(in thousands)	
Cash flow hedges	$ (768)	$ 78
Non-accounting hedges	4,187	3,293
Total fair value	$3,419	$3,371

Gains and losses on energy-related derivative contracts that are not designated or fail to qualify as hedges are recognized in the statements of income as incurred. Gains and losses on energy-related derivatives designated as cash flow hedges are mainly used to hedge anticipated purchases and sales and are initially deferred in other comprehensive income before being recognized in income in the same period as the hedged transaction. The pre-tax gains/(losses) reclassified from other comprehensive income to revenue and fuel expense were not material for any period presented and are not expected to be material for 2009. Additionally, no material ineffectiveness was recorded in earnings for any period presented. The Company has energy-related hedges in place through 2010. At December 31, 2008, there were approximately $10.9 million of deferred pre-tax realized net hedging gains relating to capitalized costs and revenues during the construction of specific plants. This will be reclassified from other comprehensive income to depreciation and amortization over the remaining life of the respective plants, which ranges from approximately 25 to 31 years. For any year presented, the pre-tax gains reclassified from other comprehensive income to depreciation and amortization have been immaterial.

At December 31, 2008, the Company had no interest derivatives outstanding. The Company has deferred pre-tax realized losses totaling $53.1 million in other comprehensive income that will be amortized to interest expense through 2016. For the years 2008, 2007, and 2006, approximately $12.0 million, $13.3 million, and $12.0 million, respectively, of pre-tax losses were reclassified from other comprehensive income to interest expense. During 2009, approximately $10.1 million of pre-tax losses are expected to be reclassified from other comprehensive income to interest expense.

All derivative financial instruments are recognized as either assets or liabilities and are measured at fair value. See Note 8 for additional information.

7. COMMITMENTS

Expansion Program

The capital program of the Company is currently estimated to be $748.9 million for 2009, $658.9 million for 2010, and $768.6 million for 2011. These amounts include estimates for potential plant acquisitions and new construction as well as ongoing capital improvements. Planned expenditures for plant acquisitions may vary due to market opportunities and the Company's ability to execute its growth strategy. Actual construction costs may vary from these estimates because of changes in factors such as: business conditions; environmental statutes and regulations; FERC rules and regulations; load projections; the cost and efficiency of construction labor, equipment, and materials; and the cost of capital.

Long-Term Service Agreements

The Company has entered into Long-Term Service Agreements (LTSAs) with General Electric and Siemens AG for the purpose of securing maintenance support for its combined cycle and combustion turbine generating facilities. In summary, the LTSAs provide that the vendors will perform all planned inspections and certain unplanned maintenance on the covered equipment, which includes the cost of all labor and materials.

Scheduled payments to the vendors, which are subject to price escalation, are made at various intervals based on actual operating hours or number of gas turbine starts of the respective units. Total remaining payments to the vendors under these agreements are currently estimated at $1.2 billion over the remaining term of the agreements, which may range up to 28 years. However, the LTSAs contain various cancellation provisions at the Company's and the applicable vendor's option. In the event of cancellation prior to scheduled work being performed, the Company is entitled to a refund of amounts paid as calculated in accordance with termination provisions of the agreements.

Payments made to the vendors prior to the performance of any planned inspections or unplanned maintenance are recorded as a prepayment in current assets or deferred charges and other assets on the balance sheets and are recorded as payments pursuant to long-term service agreements in the statement of cash flows. Inspection and maintenance costs are capitalized or charged to expense based on the nature of the work when performed. These transactions are non-cash and are not reflected in the statements of cash flows.

Fuel and Purchased Power Commitments

SCS, as agent for the traditional operating companies and the Company, has entered into various fuel transportation and procurement agreements to supply a portion of the fuel (primarily natural gas) requirements for the operating facilities. In most cases, these contracts contain provisions for firm transportation costs, storage costs, minimum purchase levels, and other financial commitments. Natural gas purchase commitments contain given volumes with prices based on various indices at the actual time of delivery; amounts included in the chart below represent estimates based on the New York Mercantile Exchange future prices at December 31, 2008. Also, the Company has entered into various long-term commitments for the purchase of electricity.

Total estimated minimum long-term obligations at December 31, 2008 were as follows:

	Natural Gas Commitments	Purchased Power Commitments[a]
	(in millions)	
2009	$ 40.6	$ 13.5
2010	139.7	13.6
2011	129.3	7.8
2012	50.1	49.2
2013	50.9	50.4
2014 and beyond	316.2	346.9
Total	$ 726.8	$ 481.4

(a) Represents contractual capacity payments.

Additional commitments for fuel will be required to supply the Company's future needs.

During 2008, the Company entered into agreements to purchase 452 MW of power from three counterparties. Approximately 352 MW of these commitment obligations will be used to serve the Company's requirements service customers. Another power purchase agreement for 100 MW will be resold to EnergyUnited Electric Membership Corporation (EnergyUnited) at cost for the period 2012 through 2021. The purchase power commitments for the EnergyUnited agreement are $35.4 million in 2012, $36.1 million in 2013 and $316.1 million in 2014 and beyond.

In addition, the Company has entered into an agreement to purchase power of up to 200 MW at the discretion of the counterparty for the period 2011 through 2018. There is no contractual capacity payment required under this agreement. Additionally, for all amounts purchased under this arrangement, the Company will pay the counterparty an amount per MW which approximates the Company's cost.

Acting as an agent for all of Southern Company's traditional operating companies and the Company, SCS may enter into various types of wholesale energy and natural gas contracts. Under these agreements, each of the traditional operating companies and the Company may be jointly and severally liable. The creditworthiness of the Company is currently inferior to the creditworthiness of the traditional operating companies; therefore, Southern Company has entered into keep-well agreements with each of the traditional operating companies to ensure they will not subsidize nor be responsible for any costs, losses, liabilities, or damages resulting from the inclusion of the Company as a contracting party under these agreements.

Operating Leases

The Company has operating lease agreements with various terms and expiration dates. Total operating lease expenses were $0.5 million, $0.5 million, and $0.6 million for 2008, 2007, and 2006, respectively. The majority of the lease expense amounts and committed future expenditures are with a joint owner of Plant Stanton Unit A.

At December 31, 2008, estimated minimum rental commitments for noncancelable operating leases were as follows:

	Operating Lease Commitments
	(in millions)
2009	$ 0.4
2010	0.4
2011	0.4
2012	0.4
2013	0.4
2014 and beyond	22.3
Total	$ 24.3

8. FAIR VALUE MEASUREMENTS

On January 1, 2008, the Company adopted FASB Statement No. 157, "Fair Value Measurements" (SFAS No. 157) which defines fair value, establishes a framework for measuring fair value, and requires additional disclosures about fair value measurements. The criterion that is set forth in SFAS No. 157 is applicable to fair value measurement where it is permitted or required under other accounting pronouncements.

SFAS No. 157 defines fair value as the exit price, which is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value measurement is based on inputs of observable and unobservable market data that a market participant would use in pricing the asset or liability. The use of observable inputs is maximized where available and the use of unobservable inputs is minimized for fair value measurement. As a means to illustrate the inputs used, SFAS No. 157 establishes a three-tier fair value hierarchy that prioritizes inputs to valuation techniques used for fair value measurement.

- Level 1 consists of observable market data in an active market for identical assets or liabilities.
- Level 2 consists of observable market data, other than that included in Level 1, that is either directly or indirectly observable.
- Level 3 consists of unobservable market data. The input may reflect the assumptions of the Company of what a market participant would use in pricing an asset or liability. If there is little available market data, then the Company's own assumptions are the best available information. The need to use unobservable inputs would typically apply to long-term energy-related derivative contracts and generally results from the nature of the energy industry, as each participant forecasts its own power supply and demand and those of other participants, which directly impact the valuation of each unique contract.

In the case of multiple inputs being used in a fair value measurement, the lowest level input that is significant to the fair value measurement represents the level in the fair value hierarchy in which the fair value measurement is reported.

The adoption of SFAS No. 157 has not resulted in any significant changes to the methodologies used for fair value measurement.

The fair value measurements performed on a recurring basis and the level of the fair value hierarchy in which they fall at December 31, 2008 are as follows:

At December 31, 2008:	Level 1	Level 2	Level 3	Total
		(in millions)		
Assets:				
Energy-related derivatives	$ -	$ 11.1	$ -	$ 11.1
Cash equivalents	37.9	-	-	37.9
Total fair value	$ 37.9	$ 11.1	$ -	$ 49.0
Liabilities:				
Energy-related derivatives total fair value	$ -	$ 7.7	$ -	$ 7.7

Energy-related derivatives primarily consist of over-the-counter contracts. See Note 6 under "Financial Instruments" for additional information. The cash equivalents consist of securities with original maturities of 90 days or less. All of these financial instruments and investments are valued primarily using the market approach.

9. QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Summarized quarterly financial information for 2008 and 2007 is as follows:

Quarter Ended	Operating Revenues	Operating Income	Net Income
		(in thousands)	
March 2008	**$ 215,532**	**$ 52,661**	**$ 28,975**
June 2008	**316,584**	**79,732**	**35,420**
September 2008	**515,871**	**118,592**	**59,562**
December 2008	**265,554**	**61,884**	**20,402**
March 2007	$ 192,492	$ 74,517	$ 32,036
June 2007	244,018	84,840	39,854
September 2007	347,751	107,208	51,438
December 2007	187,753	24,510	8,309

The Company's business is influenced by seasonal weather conditions. Fourth quarter 2007 operating income and net income were impacted by the loss on the gasifier portion of the IGCC project of $17.6 million pretax and $10.7 million after tax.

SELECTED CONSOLIDATED FINANCIAL AND OPERATING DATA 2004-2008

Southern Power Company and Subsidiary Companies 2008 Annual Report

	2008	2007	2006	2005	2004
Operating Revenues (in thousands):					
Wholesale - non-affiliates	**$667,979**	$416,648	$279,384	$223,058	$266,463
Wholesale - affiliates	**638,266**	547,229	491,762	556,664	425,065
Total revenues from sales of electricity	**1,306,245**	963,877	771,146	779,722	691,528
Other revenues	**7,296**	8,137	5,902	1,282	9,783
Total	**$1,313,541**	$972,014	$777,048	$781,004	$701,311
Net Income (in thousands)	**$144,359**	$131,637	$124,469	$114,791	$111,508
Cash Dividends on Common Stock (in thousands)	**$94,500**	$ 89,800	$ 77,700	$ 72,400	$ 207,000
Return on Average Common Equity (percent)	**13.03**	12.52	13.16	13.68	12.23
Total Assets (in thousands)	**$2,813,140**	$2,768,774	$2,690,943	$2,302,976	$2,067,013
Gross Property Additions/Plant Acquisitions (in thousands)	**$49,964**	$139,198	$465,026	$241,103	$115,606
Capitalization (in thousands):					
Common stock equity	**$1,138,361**	$1,077,887	$1,025,504	$866,343	$811,611
Long-term debt	**1,297,353**	1,297,099	1,296,845	1,099,520	1,099,435
Total (excluding amounts due within one year)	**$2,435,714**	$2,374,986	$2,322,349	$1,965,863	$1,911,046
Capitalization Ratios (percent):					
Common stock equity	**46.7**	45.4	44.2	44.1	42.5
Long-term debt	**53.3**	54.6	55.8	55.9	57.5
Total (excluding amounts due within one year)	**100.0**	100.0	100.0	100.0	100.0
Security Ratings:					
Unsecured Long-Term Debt -					
Moody's	**Baa1**	Baa1	Baa1	Baa1	Baa1
Standard and Poor's	**BBB+**	BBB+	BBB+	BBB+	BBB+
Fitch	**BBB+**	BBB+	BBB+	BBB+	BBB+
Kilowatt-Hour Sales (in thousands):					
Sales for resale - non-affiliates	**7,573,713**	6,985,592	5,093,527	3,932,638	5,369,261
Sales for resale - affiliates	**9,402,020**	10,766,003	8,493,441	6,355,249	6,583,017
Total	**16,975,733**	17,751,595	13,586,968	10,287,887	11,952,278
Average Revenue Per Kilowatt-Hour (cents)	**7.69**	5.43	5.68	7.58	5.79
Plant Nameplate Capacity Ratings (year-end) (megawatts)	**7,555**	6,896	6,733	5,403	4,775
Maximum Peak-Hour Demand (megawatts):					
Winter	**3,042**	2,815	2,780	2,037	2,098
Summer	**3,538**	3,717	2,869	2,420	2,740
Annual Load Factor (percent)	**50.0**	48.2	53.6	48.9	54.4
Plant Availability (percent)	**96.0**	96.7	98.3	97.6	97.9
Source of Energy Supply (percent):					
Gas	**75.6**	70.4	68.3	72.6	61.9
Purchased power -					
From non-affiliates	**11.3**	8.8	9.6	9.6	24.7
From affiliates	**13.1**	20.8	22.1	17.8	13.4
Total	**100.0**	100.0	100.0	100.0	100.0

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PART III

Items 10, 11, 12 (except for "Equity Compensation Plan Information" which is included herein on page III-42), 13, and 14 for Southern Company are incorporated by reference to Southern Company's Definitive Proxy Statement relating to the 2009 Annual Meeting of Stockholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, 13, and 14 for Alabama Power, Georgia Power, and Mississippi Power are incorporated by reference to the Definitive Information Statements of Alabama Power, Georgia Power, and Mississippi Power relating to each of their respective 2009 Annual Meetings of Shareholders. Specifically, reference is made to "Nominees for Election as Directors," "Corporate Governance," and "Section 16(a) Beneficial Ownership Reporting Compliance" for Item 10, "Executive Compensation Information," "Compensation Discussion and Analysis," "Compensation and Management Succession Committee Report," "Director Compensation," and "Director Compensation Table" for Item 11, "Stock Ownership Table" for Item 12, "Certain Relationships and Related Transactions" and "Director Independence" for Item 13, and "Principal Public Accounting Firm Fees" for Item 14.

Items 10, 11, 12, and 13 for Southern Power are omitted pursuant to General Instruction I(2)(c) of Form 10-K.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Identification of directors of Gulf Power.

Susan N. Story President and Chief Executive Officer Age 48 Served as Director since 2003	**Fred C. Donovan, Sr.** (1) Age 68 Served as Director since 1991
C. LeDon Anchors (1) Age 68 Served as Director since 2001	**William A. Pullum** (1) Age 61 Served as Director since 2001
William C. Cramer, Jr. (1) Age 56 Served as Director since 2002	**Winston E. Scott** (1) Age 58 Served as Director since 2003

(1) *No position other than director.*

Each of the above is currently a director of Gulf Power, serving a term running from the last annual meeting of Gulf Power's shareholders (June 24, 2008) for one year until the next annual meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as a director, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of executive officers of Gulf Power.

Susan N. Story President and Chief Executive Officer Age 48 Served as Executive Officer since 2003	**Theodore J. McCullough** Vice President – Senior Production Officer Age 45 Served as Executive Officer since 2007
P. Bernard Jacob Vice President – Customer Operations Age 54 Served as Executive Officer since 2003	**Bentina C. Terry** Vice President – External Affairs and Corporate Services Age 38 Served as Executive Officer since 2007
Philip C. Raymond Vice President and Chief Financial Officer Age 49 Served as Executive Officer since 2008	

Each of the above is currently an executive officer of Gulf Power, serving a term running from the last annual organizational meeting of the directors (July 24, 2008) for one year until the next annual organizational meeting or until a successor is elected and qualified.

There are no arrangements or understandings between any of the individuals listed above and any other person pursuant to which he or she was or is to be selected as an officer, other than any arrangements or understandings with directors or officers of Gulf Power acting solely in their capacities as such.

Identification of certain significant employees. *None.*

Family relationships. *None.*

Business experience. *Unless noted otherwise, each director has served in his or her present position for at least the past five years.*

Susan N. Story – President and Chief Executive Officer.

C. LeDon Anchors – Attorney and President of Anchors Smith Grimsley, Attorneys at Law, Fort Walton Beach, Florida. He is a director of Beach Community Bank.

William C. Cramer, Jr. - President and owner of Tommy Thomas Chevrolet, Panama City, Florida.

Fred C. Donovan, Sr. - Chairman and Chief Executive Officer of Baskerville-Donovan, Inc. (an architectural and engineering firm), Pensacola, Florida.

William A. Pullum – President/Director of Bill Pullum Realty, Inc., Navarre, Florida.

Winston E. Scott – Dean, College of Aeronautics, Florida Institute of Technology, Melbourne, Florida since August 2008. He previously served as Vice President and Deputy General Manager, Engineering and Science Contract Group at Jacobs Engineering, Houston, Texas, from 2006 to 2008 and Executive Director of the Florida Space Authority, Cape Canaveral, Florida, from 2003 to 2006.

P. Bernard Jacob – Vice President of Customer Operations since 2007. He previously served as Vice President of External Affairs and Corporate Services from 2003 to 2007.

Philip C. Raymond - Vice President and Chief Financial Officer since April 2008. He previously served as Vice President and Comptroller of Alabama Power from January 2005 to April 2008 and Eastern Region Internal

Auditing Director of SCS from September 2003 through January 2005.

Theodore J. McCullough – Vice President and Senior Production Officer since 2007. He previously served as the Manager of Georgia Power's Plant Branch from December 2003 to August 2007.

Bentina C. Terry – Vice President of External Affairs and Corporate Services since 2007. She previously served as General Counsel and Vice President of External Affairs for Southern Nuclear from January 2005 to March 2007 and Area Distribution Manager of Georgia Power from February 2004 through January 2005.

Involvement in certain legal proceedings. None.

Section 16(a) Beneficial Ownership Reporting Compliance. None.

Code of Ethics

The registrants collectively have adopted a code of business conduct and ethics that applies to each director, officer, and employee of the registrants and their subsidiaries. The code of business conduct and ethics can be found on Southern Company's website located at www.southerncompany.com. The code of business conduct and ethics is also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308. Any amendment to or waiver from the code of ethics that applies to executive officers and directors will be posted on the website.

Corporate Governance

Southern Company has adopted corporate governance guidelines and committee charters. The corporate governance guidelines and the charters of Southern Company's Audit Committee, Compensation and Management Succession Committee, Finance Committee, Governance Committee, and Nuclear/Operations Committee can be found on Southern Company's website located at www.southerncompany.com. The corporate governance guidelines and charters are also available free of charge in print to any shareholder by requesting a copy from Melissa K. Caen, Assistant Corporate Secretary, Southern Company, 30 Ivan Allen Jr. Boulevard NW, Atlanta, Georgia 30308.

ITEM 11. EXECUTIVE COMPENSATION

COMPENSATION DISCUSSION AND ANALYSIS

In this Compensation Discussion and Analysis (CD&A) and this Form 10-K, references to the "Compensation Committee" are to the Compensation and Management Succession Committee of the Board of Directors of Southern Company.

GUIDING PRINCIPLES AND POLICIES

Southern Company, through a single executive compensation program for all officers of its subsidiaries, drives and rewards both Southern Company financial performance and individual business unit performance.

This executive compensation program is based on a philosophy that total executive compensation must be competitive with the companies in our industry, must be tied to and motivate our executives to meet our short- and long-term performance goals, and must foster and encourage alignment of executive interests with the interests of our stockholders and our customers. The program generally is designed to motivate all employees, including executives, to achieve operational excellence and financial goals while maintaining a safe work environment.

The executive compensation program places significant focus on rewarding performance. The program is performance-based in several respects:

- Southern Company's actual earnings per share (EPS) and Gulf Power's business unit performance, which includes return on equity (ROE), compared to target performance levels established early in the year, determine the ultimate annual incentive payouts.
- Southern Company common stock (Common Stock) price changes result in higher or lower ultimate values of stock options.
- Southern Company's dividend payout and total shareholder return compared to those of its industry peers lead to higher or lower payouts under the Performance Dividend Program (performance dividends).

In support of the performance-based pay philosophy, we have no general employment contracts with our named executive officers or guaranteed severance, except upon a change-in-control, and no pay is conditioned solely upon continued employment with any of the named executive officers, other than base salary.

The pay-for-performance principles apply not only to the named executive officers, but to hundreds of Gulf Power employees. The annual incentive program covers almost all of the approximately 1,300 Gulf Power employees and our change-in-control protection program covers all Gulf Power employees not part of a collective bargaining unit. Stock options and performance dividends cover approximately 250 Gulf Power employees. These programs engage our people in our business, which ultimately is good not only for them, but for Gulf Power's customers and Southern Company's stockholders.

OVERVIEW OF EXECUTIVE COMPENSATION COMPONENTS

The executive compensation program is composed of several components, each of which plays a different role. The table below discusses the intended role of each material pay component, what it rewards, and why we use it. Following the table is additional information that describes how we made 2008 pay decisions.

Pay Element	Intended Role and What the Element Rewards	Why We Use the Element
Base Salary	Base salary is pay for competence in the executive role, with a focus on scope of responsibilities.	Market practice. Provides a threshold level of cash compensation for job performance.
Annual Incentive	Gulf Power's annual incentive program rewards achievement of operational, EPS, and business unit financial goals.	Market practice. Focuses attention on achievement of short-term goals that ultimately work to fulfill our mission to customers and lead to increased stockholder value in the long-term.
Long-Term Incentive: Stock Options	Stock options reward price increases in Common Stock over the market price on the date of grant, over a 10-year term.	Performance-based compensation. Aligns executives' interests with those of Southern Company's stockholders. Market practice.
Long-Term Incentive: Performance Dividends	Performance dividends provide cash compensation dependent on the number of stock options held at year end, Southern Company's declared dividends on the Common Stock during the year, and Southern Company's four-year total shareholder return versus industry peers.	Performance-based compensation. Enhances the value of stock options and focuses executives on maintaining a significant dividend yield for Southern Company's stockholders. Aligns executives' interests with Southern Company's stockholders' interests since payouts are dependent on performance, defined as Common Stock performance vs. industry peers. Market practice.
Southern Excellence Awards	An employee may receive discretionary cash or non-cash awards based on extraordinary performance. Awards are not tied to pre-established goals.	Provides a means of rewarding, on a current basis, extraordinary performance.
Relocation Incentive	Lump sum payment of 10% of base salary provides incentive to geographically relocate.	Enhances the value of the relocation program perquisite.

Pay Element	Intended Role and What the Element Rewards	Why We Use the Element
Retirement Benefits	The Southern Company Deferred Compensation Plan (Deferred Compensation Plan) provides the opportunity to defer to future years all or part of base salary and annual incentive in either a prime interest rate account or Common Stock account. Executives participate in employee benefit plans available to all employees of Gulf Power, including a 401(k) savings plan and the funded Southern Company Pension Plan (Pension Plan). The Supplemental Benefit Plan counts pay, including deferred salary, ineligible to be counted under the Pension Plan and the 401(k) plan due to Internal Revenue Service rules. The Supplemental Executive Retirement Plan counts short-term incentive pay above 15% of base salary for pension purposes.	Permitting compensation deferral is a cost-effective method of providing additional cash flow to Gulf Power while enhancing the retirement savings of executives. The purpose of these supplemental plans is to eliminate the effect of tax limitations on the payment of retirement benefits. Represents an important component of competitive market-based compensation in Southern Company's peer group and generally.
Perquisites and Other Personal Benefits	Personal financial planning maximizes the perceived value of our executive compensation program to executives and allows executives to focus on Gulf Power's operations. Home security systems lower the risk of harm to executives. Club memberships are provided primarily for business use. Relocation benefits cover the costs associated with geographic relocation at the request of the employer.	Perquisites benefit both Gulf Power and executives, at low cost to Gulf Power.
Post-Termination Pay	Change-in-control plans provide severance pay, accelerated vesting, and payment of short- and long-term incentive awards upon a change-in-control of Gulf Power or Southern Company coupled with involuntary termination not for "Cause" or a voluntary termination for "Good Reason."	Providing protections to senior executives upon a change-in-control minimizes disruption during a pending or anticipated change-in-control. Payment and vesting occur only in the event of both an actual change-in-control and loss of the executive's position.

MARKET DATA

For the named executive officers, we review compensation data from large, publicly-owned electric and gas utilities. The data was developed and analyzed by Towers Perrin, the compensation consultant retained by the Compensation Committee. The companies included each year in the primary peer group are those whose data is available through the consultant's database. Those companies are drawn from this list of regulated utilities of $2 billion in revenues and up. Proxy data for the entire list of companies below also is used. No other companies' data are used in our market-pay benchmarking.

AGL Resources Inc.	Energy East Corporation	Pinnacle West Capital Corporation
Allegheny Energy Corporation	Entergy Corporation	PPL Corporation
Alliant Energy Corporation	Exelon Corporation	Progress Energy, Inc.
Ameren Corporation	FirstEnegy Corp.	Public Service Enterprise Group Inc.
American Electric Power Company, Inc.	FPL Group, Inc.	Puget Energy Inc.
Atmos Energy Corporation	Integrys Energy Company, Inc.	Reliant Energy, Inc.
Calpine Corporation	MDU Resources, Inc.	Salt River Project
CenterPoint Energy, Inc	Mirant Corporation	SCANA Corporation
CMS Energy Corporation	New York Power Authority	Sempra Energy
Consolidated Edison, Inc.	Nicor, Inc.	Sierra Pacific Resources
Constellation Energy Group, Inc.	Northeast Utilities	Southern Union Company
Dominion Resources Inc.	NRG Energy, Inc.	Tennessee Valley Authority
Duke Energy Corporation	NSTAR	The Williams Companies, Inc.
Dynegy Inc.	OGE Energy Corp.	Wisconsin Energy Corporation
Edison International	Pepco Holdings, Inc.	Xcel Energy Inc.

Southern Company is one of the largest U.S. utility companies in revenues and market capitalization, and its largest business units are some of the largest in the industry as well. For that reason, the consultant size-adjusts the market data in order to fit it to the scope of our business.

In using this market data, market is defined as the size-adjusted 50th percentile of the data, with a focus on pay opportunities at target performance (rather than actual plan payouts). Gulf Power specifically looks at the market data for chief executive officer positions and other positions in terms of scope of responsibilities that most closely resemble the positions held by the named executive officers. Based on that data, Gulf Power establishes a total target compensation opportunity for each named executive officer. Total target compensation opportunity is the sum of base salary, annual incentive at the target performance level and stock option awards with associated performance dividends at a target value. Actual compensation paid may be more or less than the total target compensation opportunity based on actual performance above or below target performance levels. As a result, the compensation program is designed to result in payouts that are market-appropriate given Gulf Power's performance for the year or period.

We did not target a specified weight for base salary or annual or long-term incentives as a percentage of total target compensation opportunities, nor did amounts realized or realizable from prior compensation serve to increase or decrease 2008 compensation amounts. Total target compensation opportunities for senior management as a group are managed to be at the median of the market for companies of our size and in our industry. The total target compensation opportunity established in 2008 for each named executive officer is shown below.

Name	Salary	Annual Incentive	Long-Term Incentive	Total Target Compensation Opportunity
S. N. Story	$396,084	$237,650	$348,550	$982,284
R. R. Labrato	$262,500	$118,126	$129,933	$510,559
P. C. Raymond	$228,433	$99,825	$72,109	$400,367
P. B. Jacob	$230,346	$103,656	$110,694	$444,696
T. J. McCullough	$182,973	$73,189	$70,439	$326,601
B. C. Terry	$228,433	$102,795	$103,732	$434,960

As is our long-standing practice, the salary levels shown above were not effective before March 2008. For Mr. Raymond, the salary level shown was not effective until April 2008 when he assumed his new position. Therefore, the amounts reported in the Summary Compensation Table are lower because that table reports actual amounts paid in 2008. For purposes of comparing the value of our compensation program to the market data, stock options were valued at 12%, and performance dividend targets at 10%, of the average daily Common Stock price for the year preceding the grant, both of which represented risk-adjusted present values on the date of grant and were consistent with the methodologies used to develop the market data. For the 2008 grant of stock options and the performance dividend targets established for the 2008 — 2011 performance period, this value was $8.03 per stock option granted. In the long-term incentive column, approximately 55% of the value shown is attributable to stock options and approximately 45% attributable to performance dividends. The stock option value used for market data comparisons exceeds the value reported in the Grants of Plan-Based Awards Table because the value above is calculated assuming that the options are held for their full 10-year terms. The calculation of the Black-Scholes value reported in the Grants of Plan-Based Awards Table uses historical holding period averages of approximately five years. The value of stock options, with the associated performance dividends, declined from 2007. In 2007, the value of the dividend equivalents was 10% of the value of the average daily Common Stock price for the year preceding the grant as in 2009, but the value of the stock options was 15% rather than 12%. In 2007, the performance dividends represented 40% of the long-term incentive value and stock options represented 60% of that value.

As discussed above, the Compensation Committee targets total target compensation opportunities for executives as a group at market. Therefore, some executives may be paid somewhat above and others somewhat below market. This practice allows for minor differentiation based on time in the position, scope of responsibilities, and individual performance. The differences in the total pay opportunities for each named executive officer are based almost exclusively on the differences indicated by the market data for persons holding similar positions. Mr. Raymond's total compensation opportunity was lower than it would have been had he been in his current position for the entire year. Because of the use of market data from a large number of peer companies for positions that are not identical in terms of scope of responsibility from company to company, we consider the total target opportunity to be at market if it is within a range of 90% to 110% of the median of the market data. The average total target compensation opportunities for the named executive officers for 2008 were within this range and therefore we continue to believe that our compensation program is market-appropriate.

In 2008, the Compensation Committee received a detailed comparison of our executive benefits program to the benefits of a group of other large utilities and general industry companies. The results indicated that our overall executive benefits program was at market.

DESCRIPTION OF KEY COMPENSATION COMPONENTS

2008 Base Salary

The named executive officers are each within a position level with a base salary range that is established under the direction of the Compensation Committee using the market data described above. Also considered in recommending the specific base salary level for each named executive officer is the need to retain an experienced team, internal equity, time in position, and individual performance. This analysis of individual performance included the degree of competence and initiative exhibited and the individual's relative contribution to the results of operations in prior years.

Base salaries for Ms. Terry and Messrs. Jacob and Raymond were recommended by Ms. Story, the Gulf Power President and Chief Executive Officer, to Mr. David M. Ratcliffe, the Southern Company President and Chief Executive Officer. Mr. McCullough currently serves as an executive officer of Gulf Power and of Southern Company's generation business unit (Southern Company Generation). His base salary was recommended by an Executive Vice President of Southern Company Generation, with input from Ms. Story, to Mr. Thomas A. Fanning, the Southern Company Chief Operating Officer. Ms. Story's base salary was approved by Mr. Ratcliffe. Mr. Labrato's base salary also was approved by Mr. Ratcliffe following his transfer to SCS to lead Southern Company's Internal Audit function which reports to Mr. Ratcliffe.

The actual base salary levels set for each of the named executive officers were set within the pre-established salary ranges.

2008 Incentive Compensation

Achieving Operational and Financial Goals — Our Guiding Principle for Incentive Compensation

Our number one priority is to provide our customers outstanding reliability and superior service at low prices while achieving a level of financial performance that benefits Southern Company's stockholders in the short and long term.

In 2008, we strove for and rewarded:

- Continued industry-leading reliability and customer satisfaction, while maintaining our low retail prices relative to the national average; and
- Meeting energy demand with the best economic and environmental choices.

In 2008, we also focused on and rewarded:

- Southern Company EPS Growth;
- Gulf Power ROE in the top quartile of comparable electric utilities;

- Common Stock dividend growth;
- Long-term, risk-adjusted Southern Company total shareholder return; and
- Financial Integrity — an attractive risk-adjusted return, sound financial policy, and a stable "A" credit rating.

The incentive compensation program is designed to encourage Gulf Power to achieve these goals.

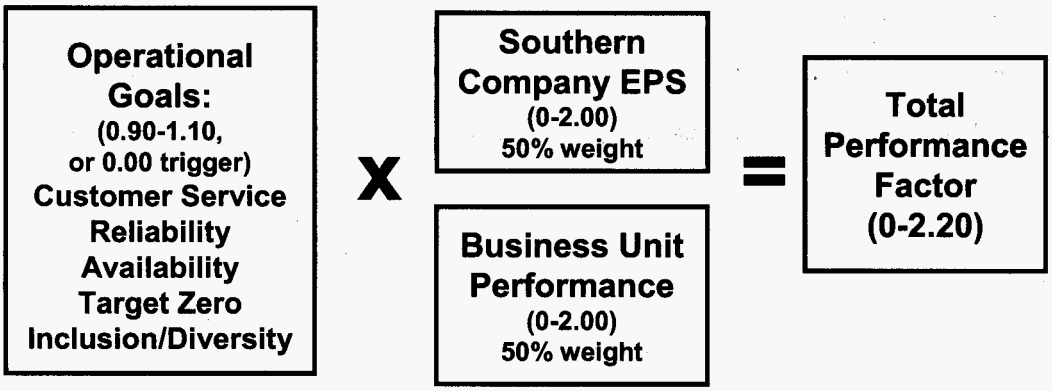
The Southern Company Chief Executive Officer, with the assistance of Southern Company's Human Resources staff, recommends to the Compensation Committee program design and award amounts for senior executives.

2008 Annual Incentive Program

Program Design
The Performance Pay Program is Southern Company's annual incentive plan. Almost all employees of Gulf Power are participants, including the named executive officers, for a total of over 1,300 Gulf Power participants.

The performance measured by the program uses goals set at the beginning of each year by the Compensation Committee.

An illustration of the annual incentive goal structure for 2008 is provided below.



- Operational goals for 2008 were safety, customer service, plant availability, transmission and distribution system reliability, inclusion, and, for Southern Company Generation, net income. Each of these operational goals is explained in more detail under "Goal Details" below. The result of all operational goals is averaged and multiplied by the bonus impact of the EPS and business unit financial goals. The amount for each goal can range from 0.90 to 1.10 or can be 0.00 if a threshold performance level is not achieved as more fully described below. The level of achievement for each operational goal is determined and the results are averaged.
- Southern Company EPS is weighted at 50% of the financial goals. EPS is defined as earnings from continuing operations divided by average shares outstanding during the year. The EPS performance measure is applicable to all participants in the Performance Pay Program, including the named executive officers.
- Business unit financial performance is weighted at 50% of the financial goals. Gulf Power's financial

performance goal is ROE, which is defined as Gulf Power's net income divided by average equity for the year. For Southern Company Generation, it is calculated using a corporate-wide weighted average of all the business unit financial performance goals, including primarily the ROE of Gulf Power and affiliated companies, Alabama Power, Georgia Power, and Mississippi Power. For Mr. McCullough, the business unit financial goal was weighted 30% Gulf Power ROE and 20% Southern Company Generation financial goal. The business unit financial goal for corporate-level employees of SCS was the Southern Company corporate-wide weighted average of all the business unit financial goals. Because Messrs. Labrato and Raymond were employed during 2008, by Gulf Power and SCS, and Alabama Power and Gulf Power, respectively, the business unit financial goals were pro-rated based upon the period of time spent with each employing company.

The Compensation Committee may make adjustments, both positive and negative, to goal achievement for purposes of determining payouts. Such adjustments include the impact of items considered one time, outside of normal operations, or not anticipated in the business plan when the earnings goal was established, and of sufficient magnitude to warrant recognition. The Compensation Committee made an adjustment in 2008 to eliminate the effect of $83 million in after-tax charges to Southern Company earnings taken in 2008. The charges related to a position Southern Company took concerning the timing of tax deductions associated with sale-in-lease-out (SILO) transactions that were challenged by the Internal Revenue Service. In making this decision, the Compensation Committee considered that the charges only affected the timing of deductions taken by Southern Company related to the SILO transactions, that the future tax benefits due to the timing change likely will be minimal in future years and will likely have no impact on future Performance Pay Program award sizes, and that the impact of the tax benefits in earlier years was minimal – an average of just over two percent in 2002 through 2007. This adjustment increased the average payout for 2008 performance by approximately 30%.

Under the terms of the program, no payout can be made if Southern Company's current earnings are not sufficient to fund its Common Stock dividend at the same level or higher than the prior year.

Goal Details

Operational Goals:

Customer Service – Gulf Power uses customer satisfaction surveys to evaluate its performance. The survey results provide an overall ranking for Gulf Power, as well as a ranking for each customer segment: residential, commercial, and industrial.

Reliability — Transmission and distribution system reliability performance is measured by the frequency and duration of outages. Performance targets for reliability are set internally based on historical performance, expected weather conditions, and expected capital expenditures.

Availability — Peak season equivalent forced outage rate is an indicator of availability and efficient generation fleet operations during the months when generation needs are greatest. The rate is calculated by dividing the number of hours of forced outages by total generation hours.

Safety – Southern Company's Target Zero program is focused on continuous improvement in having a safe work environment. The performance is measured by the Occupational Safety and Health Administration recordable incident rate.

Inclusion/Diversity – The inclusion program seeks to improve our inclusive workplace. This goal includes measures for work environment (employee satisfaction survey), representation of minorities and females in leadership roles, and supplier diversity.

Southern Company capital expenditures "gate" or threshold goal – Southern Company strived to manage total capital expenditures, excluding nuclear fuel, for the participating business units at or below $4.135 billion for 2008. If the capital expenditure target is exceeded, total operational goal performance is capped at 0.90 for all business units, regardless of the actual operational goal results. Adjustments to the goal may occur due to significant events

not anticipated in Southern Company's business plan established early in 2008, such as acquisitions or disposition of assets, new capital projects, and other events.

For Mr. McCullough, the operational goals were weighted 60% based on Gulf Power's operational goals and 40% based on Southern Company Generation's operational goals. During 2008, Mr. Labrato was employed by Gulf Power for a period of time and SCS for the remainder of the year. Mr. Raymond was employed by Alabama Power for a period of time and Gulf Power for the remainder of the year. The operational goals for Messrs. Labrato and Raymond were pro-rated based on the period of time spent with each employing company.

The range of performance levels established for the operational goals are detailed below.

Level of Performance	**Customer Service**	**Reliability**	**Availability – Gulf Power/ Southern Company Generation/ Alabama Power %**	**Safety - Gulf Power/ Southern Company Generation/ Alabama Power**	**Inclusion**
Maximum (1.10)	Top quartile for each customer segment	Improve historical performance	2.25/2.00/2.00	0.95/0.20/0.95	Significant improvement
Target (1.00)	Top quartile	Maintain historical performance	3.00/2.75/2.75	1.25/0.50/1.25	Improve
Threshold (0.90)	3rd quartile	Below historical performance	4.00/3.75/3.75	1.50/0.80/1.50	Below expectations
0 Trigger	4th quartile	Significant issues	9.00/6.00/6.00	>1.50/>0.80/>1.50	Significant issues

EPS and Business Unit Financial Performance:

The range of EPS and business unit financial goals for 2008 is shown below. The ROE goal varies from the allowed retail ROE range due to state regulatory accounting requirements, wholesale activities, other non-jurisdictional revenues and expenses, and other activities not subject to state regulation.

Level of Performance	EPS	Business unit financial performance ROE	Payout Factor	Payout Factor at Highest Level of Operational Goal Achievement	Payout Below Threshold for Operational Goal Achievement
Maximum	$2.45	14.25%	2.00	2.20	0.00
Target	$2.32	13.25%	1.00	1.10	0.00
Threshold	$2.24	11.00%	0.50	0.275	0.00
Below threshold	<$2.24	<11.00%	0.00	0.00	0.00

2008 Achievement

Each named executive officer had a target annual incentive opportunity, based on his or her position, set by the Compensation Committee at the beginning of 2008. Targets are set as a percentage of base salary. Ms. Story's target was set at 60%. For Ms. Terry and Messrs. Jacob and Labrato, it was set at 45%. For Mr. Raymond, it was initially set at 40% based on his former position level and increased to 45% in April 2008 when he assumed his current position. For Mr. McCullough, it was set at 40%. Actual payouts were determined by adding the payouts derived from EPS and business unit financial performance goal achievement for 2008 and multiplying that sum by the result of the operational goal achievement. The gate goal target was not exceeded and therefore did not affect

payouts. Actual 2008 goal achievement is shown in the following table. The EPS result shown in the table is adjusted for the after-tax charges taken in 2008 as described above. Therefore, payouts were determined using EPS performance results that differed from the results reported in the financial statements of Southern Company in Item 8 herein. EPS, as determined in accordance with Generally Accepted Accounting Principles and as reported in the financial statements of Southern Company in Item 8 herein was $2.26 per share.

Business Unit	Operational Goal Multiplier (A)	EPS	EPS Goal Performance Factor (50% Weight)	Business Unit Financial Performance	Business Unit Financial Performance Factor (50% Weight)	Total Weighted Financial Performance Factor (B)	Total Payout Factor (AxB)
Gulf Power	1.02	$2.37	1.54	12.66%	0.87	1.20	1.23
Southern Company Generation	1.09	$2.37	1.54	Corporate Average	1.24	1.39	1.51
Alabama Power	1.07	$2.37	1.54	13.30% ROE	1.05	1.29	1.39
SCS	1.07	$2.37	1.54	Corporate Average	1.24	1.39	1.49

Note that the Total Payout Factor may vary from the Total Weighted Performance multiplied by the operational goal multiplier due to rounding. To calculate the annual incentive payout amount, the target opportunity (annual incentive target times base salary) is multiplied by the Total Payout Factor.

Actual performance exceeded the target performance levels established by the Compensation Committee in early 2008; therefore, the payout levels also exceeded the target pay opportunities that were established. More information on how target pay opportunities are established is provided under the section entitled Market Data in this CD&A.

The table below shows the pay opportunity set in early 2008 for the annual incentive payout at target-level performance and the actual payout based on the actual performance, as adjusted, shown above.

Name	**Target Annual Incentive Opportunity ($)**	**Actual Annual Incentive Payout ($)**
S. N. Story	237,650	292,310
R. R. Labrato	118,126	168,021
P. C. Raymond	99,825	126,586
P. B. Jacob	103,656	127,496
T. J. McCullough	73,189	98,073
B. C. Terry	102,795	126,438

Stock Options

Options to purchase Common Stock are granted annually and were granted in 2008 to the named executive officers and about 250 other employees of Gulf Power. Options have a 10-year term, vest over a three-year period, fully vest upon retirement or termination of employment following a change-in-control, and expire at the earlier of five years from the date of retirement or the end of the 10-year term.

Stock option award sizes for 2008 were calculated using guidelines set by the Compensation Committee as a percentage of base salary as shown in the table below. The number of options granted is the guideline amount divided by Southern Company's average daily Common Stock price for the 12 months preceding the grant. The guideline percentage was set by the Compensation Committee to deliver target long-term incentive compensation assuming a stock option value, with associated performance dividends, of approximately 25% of the Common Stock

price. As discussed in the Market Data section in this CD&A, in 2008 the target value of the stock options, with the associated performance dividends, was only 22% of the Common Stock price. Therefore, while the guideline as a percentage of salary was not increased for 2008 stock option awards, the target value of long-term incentive compensation was less in 2008 than in 2007. ($8.03 per share in 2008 and $8.515 per share in 2007.)

The calculation of the 2008 stock option grants for the named executive officers is shown below.

Name	Guideline %	Salary	Guideline Amount	Average Daily Stock Price	Number of Stock Options Granted (Guideline Amount/Average Daily Stock Price)
S. N. Story	400% of Salary	$396,084	$1,584,336	$36.50	43,406
R. R. Labrato	225% of Salary	$262,500	$590,625	$36.50	16,181
P. C. Raymond	175% of Salary	$187,297	$327,770	$36.50	8,980
P. B. Jacob	225% of Salary	$223,623	$503,152	$36.50	13,785
T. J. McCullough	175% of Salary	$182,973	$320,203	$36.50	8,772
B. C. Terry	225% of Salary	$209,557	$471,503	$36.50	12,918

The guideline percentage is based on the position held on the date the grants are made. Also, grants were made based on salaries in effect on March 1, 2008.

More information about the option program is contained in the Grant of Plan Based Awards Table and the information accompanying it.

Performance Dividends

All option holders, including the named executive officers, can receive performance-based dividend equivalents on stock options held at the end of the year. Performance dividends can range from 0% to 100% of the Common Stock dividend paid during the year per option held at the end of the year. Actual payout will depend on Southern Company's total shareholder return over a four-year performance measurement period compared to a group of other electric and gas utility companies. The peer group is determined at the beginning of each four-year performance-measurement period. The peer group varies from the Market Data peer group due to the timing and criteria of the peer selection process. The peer group for performance dividends is set by the Compensation Committee at the beginning of the four-year performance-measurement period. However, despite these timing differences, there is substantial overlap in the companies included.

Total shareholder return is calculated by measuring the ending value of a hypothetical $100 invested in each company's common stock at the beginning of each of 16 quarters. In the final year of the performance-measurement period, Southern Company's ranking in the peer group is determined at the end of each quarter and the percentile ranking is multiplied by the actual Common Stock dividend paid in that quarter. To determine the total payout per stock option held at the end of the performance-measurement period, the four quarterly amounts earned are added together.

No performance dividends are paid if Southern Company's earnings are not sufficient to fund a Common Stock dividend at least equal to that paid in the prior year.

2008 Payout

The peer group used to determine the 2008 payout for the 2005-2008 performance-measurement period was made up of utilities with revenues of $2 billion or more with regulated revenues of 70% or more. Those companies are listed below.

Allegheny Energy, Inc.	Exelon Corporation	Progress Energy, Inc.
Alliant Energy Corporation	FirstEnergy Corporation	Public Service Enterprise Group Inc.
Ameren Corporation	FPL Group, Inc.	Puget Energy, Inc.
American Electric Power Company, Inc.	NiSource Inc.	SCANA Corporation
Consolidated Edison, Inc.	NSTAR	Sempra Energy
DTE Energy Company	OGE Energy Corp.	Sierra Pacific Resources
Energy East Corporation	Pepco Holdings, Inc.	Wisconsin Energy Corporation
Entergy Corporation	Pinnacle West Capital Corp.	Xcel Energy Inc.

The scale below determined the percentage of the full year's dividend paid on each option held at December 31, 2008 based on the 2005-2008 performance-measurement period. Payout for performance between points was interpolated on a straight-line basis.

Performance vs. Peer Group	**Payout (% of Each Quarterly Dividend Paid)**
90th percentile or higher	100%
50th percentile	50%
10th percentile or lower	0%

The above payout scale, when established in early 2005, paid 25% of the dividend at the 30th percentile and zero below that. The scale was extended to the 10th percentile on a straight-line basis by the Compensation Committee in October 2005, in order to avoid the earnings volatility and employee relations issues that the payout cliff created.

Southern Company's total shareholder return performance during each quarter of the final year of the four-year performance-measurement period ending with 2008 was the 61st, 48th, 91st, and 91st percentile, respectively, resulting in a total payout of 78% of the full year's Common Stock dividend, or $1.30. This figure was multiplied by each named executive officer's outstanding stock options at December 31, 2008 to calculate the payout under the program. The amount paid is included in the Non-Equity Incentive Plan Compensation column in the Summary Compensation Table.

2011 Opportunity

The peer group for the 2008-2011 performance-measurement period (which will be used to determine the 2011 payout) is made up of utility companies with revenues of $1.2 billion or more with regulated revenues of approximately 60% or more. Those companies are listed below.

The guideline used to establish the peer group for the 2005-2008 performance-measurement period was somewhat different from that used in 2008 to establish the peer group for the 2008-2011 performance-measurement period. The guideline for inclusion in the peer group is reevaluated annually as needed to assist in identifying an appropriate number of companies similar to Southern Company. While the guideline does vary somewhat, 20 of the 24 companies in the peer group for the 2005-2008 performance-measurement period also are in the peer group established for the 2008-2011 performance-measurement period.

Allegheny Energy, Inc.	Edison International	Progress Energy, Inc.
Alliant Energy Corporation	Energy East Corporation	Public Service Enterprise Group Inc.
Ameren Corporation	Entergy Corporation	Puget Energy, Inc.
American Electric Power Company, Inc.	Exelon Corporation	SCANA Corporation
Aquila, Inc.	FPL Group, Inc.	Sierra Pacific Resources
Avista Corporation	Hawaiian Electric Industries, Inc.	TECO Energy, Inc.
CMS Energy Corporation	NiSource Inc.	UIL Holdings Corporation
Consolidated Edison, Inc.	Northeast Utilities	Unisource Energy Corporation
Dominion Resources Inc.	NSTAR	Vectren Corporation
DPL Inc.	Pepco Holdings, Inc.	Westar Energy, Inc.
DTE Energy Company	PG&E Corporation	Wisconsin Energy Corporation
Duke Energy Corporation	Pinnacle West Capital Corp.	Xcel Energy Inc.

The scale below will determine the percentage of each quarter's dividend paid in the last year of the performance-measurement period to be paid on each option held at December 31, 2011, based on the 2008-2011 performance-measurement period. Payout for performance between points is interpolated on a straight-line basis.

Performance vs. Peer Group	Payout (% of Each Quarterly Dividend Paid)
90th percentile or higher	100%
50th percentile	50%
10th percentile or lower	0%

See the Grants of Plan-Based Awards Table and the information accompanying it for more information about threshold, target, and maximum payout opportunities for the 2008-2011 Performance Dividend Program.

Southern Excellence Awards

The President and CEO of Gulf Power approved discretionary cash awards to Ms. Terry and Mr. Raymond for their leadership of a special project during 2008.

Timing of Incentive Compensation

As discussed above, Southern Company EPS and Gulf Power's financial performance goal for the 2008 annual incentive program were established at the February 2008 Compensation Committee meeting. Annual stock option grants also were made at that meeting. The establishment of incentive compensation goals and the granting of stock options were not timed with the release of non-public material information. This procedure was consistent with prior practices. Stock option grants are made to new hires or newly-eligible participants on preset, regular quarterly dates that were approved by the Compensation Committee. The exercise price of options granted to employees in 2008 was the closing price of the Common Stock on the date of grant.

Post-Employment Compensation

As mentioned above, we provide certain post-employment compensation to employees, including the named executive officers:

Retirement Benefits

Generally, all full-time employees of Gulf Power, including the named executive officers, participate in our funded Pension Plan after completing one year of service. Normal retirement benefits become payable when participants both attain age 65 and complete five years of participation. We also provide unfunded benefits that count salary and annual incentive pay that is ineligible to be counted under the Pension Plan. (These plans are the Supplemental Benefit Plan and the Supplemental Executive Retirement Plan that are mentioned in the chart on page III-29 of this CD&A.) See the Pension Benefits Table and the information accompanying it for more information about pension-related benefits.

Gulf Power also provides the Deferred Compensation Plan which is an unfunded plan that permits participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, disability, death, or other separation from service. Up to 50% of base salary and up to 100% of the annual incentive and performance dividends may be deferred, at the election of eligible employees. All of the named executive officers are eligible to participate in the Deferred Compensation Plan. See the Nonqualified Deferred Compensation Table and the information accompanying it for more information about the Deferred Compensation Plan.

Change-in-Control Protections

The Compensation Committee approved the change-in-control protection program in 1998. The program provides some level of severance benefits to all employees who are not part of a collective bargaining unit, if the conditions of the program are met, as described below. The Compensation Committee established this program and the levels of severance amount in order to provide certain compensatory protections to executives upon a change-in-control and thereby allow them to negotiate aggressively with a prospective purchaser. Providing such protections to our employees in general minimizes disruption during a pending or anticipated change-in-control. For all participants, payment and vesting occur only upon the occurrence of both an actual change-in-control and loss of the individual's position.

Change-in-control protections, including severance pay and, in some situations, vesting or payment of long-term incentive awards, are provided upon a change-in-control of Southern Company or Gulf Power coupled with an involuntary termination not for "Cause" or a voluntary termination for "Good Reason." This means there is a "double trigger" before severance benefits are paid; *i.e.,* there must be both a change-in-control and a termination of employment.

If the conditions described above are met, the named executive officers are entitled to severance payments equal to two or three times their base salary plus the annual incentive amount assuming target-level performance. Most officers, including Gulf Power's named executive officers, are entitled to severance payments equal to two times their base salary plus the annual incentive amount assuming target-level performance. Ms. Story is entitled to the larger amount. These amounts are consistent with that provided by other companies of our size and in our industry and were established based on market-data provided to the Compensation Committee from its compensation consultant.

More information about post-employment compensation, including severance arrangements under our change-in-control program, is included in the section entitled Potential Payments upon Termination or Change-in-Control.

Executive Stock Ownership Requirements

Effective January 1, 2006, the Compensation Committee adopted Common Stock ownership requirements for officers of Southern Company and its subsidiaries that are in a position of Vice President or above. All of the named executive officers are covered by the requirements. The guidelines were implemented to further align the interest of officers and Southern Company's stockholders by promoting a long-term focus and long-term share ownership.

The types of ownership arrangements counted toward the requirements are shares owned outright, those held in Southern Company-sponsored plans, and Common Stock accounts in the Deferred Compensation Plan and the Supplemental Benefit Plan. One-third of vested Southern Company stock options may be counted, but if so, the ownership requirement is doubled.

The requirements are expressed as a multiple of base salary as per the table below.

Name	Multiple of Salary Without Counting Stock Options	Multiple of Salary Counting 1/3 of Vested Options
S. N. Story	3 Times	6 Times
R. R. Labrato	2 Times	4 Times
P. C. Raymond	2 Times	4 Times
P. B. Jacob	2 Times	4 Times
T. J. McCullough	1 Time	2 Times
B. C. Terry	2 Times	4 Times

Current officers have until September 30, 2011 to meet the applicable ownership requirement. Newly-elected officers have five years from the date of their election to meet the applicable ownership requirement.

Impact of Accounting and Tax Treatments on Compensation

None of the compensation paid to the Gulf Power's employees, including the named executive officers, is subject to the restrictions under Section 162(m) of the Internal Revenue Code of 1986, as amended (Code).

Policy on Recovery of Awards

Southern Company's 2006 Omnibus Incentive Compensation Plan provides that if Southern Company or Gulf Power is required to prepare an accounting restatement due to material noncompliance as a result of misconduct, and if an executive knowingly or grossly negligently engaged in or failed to prevent the misconduct or is subject to automatic forfeiture under the Sarbanes-Oxley Act of 2002, the executive will reimburse Gulf Power the amount of any payment in settlement of awards earned or accrued during the 12-month period following the first public issuance or filing that was restated.

Southern Company Policy Regarding Hedging the Economic Risk of Stock Ownership

Southern Company's policy is that insiders, including outside directors, will not trade in Southern Company options on the options market and will not engage in short sales.

COMPENSATION COMMITTEE REPORT

The Compensation Committee met with management to review and discuss the CD&A. Based on such review and discussion, the Compensation Committee recommended to the Southern Company Board of Directors that the CD&A be included in Gulf Power's Annual Report on Form 10-K for the fiscal year ended December 31, 2008. The Southern Company Board of Directors approved that recommendation.

Members of the Compensation Committee:

J. Neal Purcell, Chair
Jon A. Boscia
H. William Habermeyer, Jr.
Donald M. James

SUMMARY COMPENSATION TABLE

The Summary Compensation Table shows the amount and type of compensation received by the Chief Executive Officer, any Chief Financial Officer, and the next three most highly-paid executive officers who served in 2008. Collectively, these officers are referred to as the "named executive officers."

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensa-tion ($) (g)	Change in Pension Value and Nonqualified Deferred Compensa-tion Earnings ($) (h)	All Other Compen-sation ($) (i)	Total ($) (j)
Susan N. Story	**2008**	390,602	0	0	170,536	509,067	128,423	39,109	1,237,737
President, Chief	2007	366,578	0	0	164,686	404,421	231,120	37,196	1,204,001
Executive Officer, and Director	2006	349,187	0	0	144,347	383,590	65,344	29,330	971,798
Ronnie R. Labrato*	**2008**	256,390	250	0	38,349	268,859	147,939	198,700	910,487
	2007	231,132	0	0	63,580	189,469	166,084	25,849	676,114
Vice President and Chief Financial Officer	2006	219,732	7,500	0	60,598	182,948	71,618	25,945	568,341
Philip C. Raymond**	**2008**	215,880	23,731	0	38,676	181,206	48,120	44,446	552,059
Vice President and Chief Financial Officer									
P. Bernard Jacob	**2008**	227,419	0	0	32,670	181,151	103,293	22,219	566,752
Vice President	2007	213,374	0	0	57,371	152,730	125,674	22,726	571,875
	2006	199,142	0	0	54,938	156,439	53,935	18,699	483,153
Theodore J. McCullough***	**2008**	180,717	0	0	21,540	139,937	30,798	78,720	451,712
	2007	154,087	17,000	0	21,345	107,045	30,674	29,962	360,113
Vice President									
Bentina C. Terry***	**2008**	222,172	5,150	0	35,751	166,985	13,845	26,250	470,153
	2007	193,869	18,232	0	36,417	140,268	13,802	64,210	466,798
Vice President									

*Mr. Labrato transferred to SCS to become the Vice President of Internal Auditing effective April 1, 2008.

**Mr. Raymond transferred from Alabama Power to become Vice President and Chief Financial Officer of Gulf Power effective April 1, 2008.
***Ms. Terry and Mr. McCullough became executive officers of Gulf Power in March 2007 and August 2007, respectively.

Column (d)

The amounts reported in this column are Southern Excellence Awards in the case of Ms. Terry and Messrs. Labrato and Raymond in 2008. Also, included in 2008 and 2007 are relocation incentives that are paid to employees who are promoted and relocate geographically, at the request of the employer which is a lump sum payment equal to 10% of base salary. Mr. Raymond relocated in 2008 and both Ms. Terry and Mr. McCullough relocated in 2007.

Column (e)

No equity-based compensation has been awarded to the named executive officers, or any other employees of Gulf Power, other than Stock Option Awards which are reported in column (f).

Column (f)

This column reports the dollar amounts recognized for financial statement reporting purposes with respect to 2008 in accordance with FASB Statement No. 123 (revised 2004), "Share-Based Payment" (SFAS No. 123R) disregarding any estimates of forfeitures relating to service-based vesting conditions. See Note 8 to the financial statements of Gulf Power in Item 8 herein for a discussion of the assumptions used in calculating these amounts.

For Messrs. Labrato and Jacob, the amounts shown equal the grant date fair value for the 2008 options granted in 2008, as reported in the Grants of Plan-Based Awards Table, because these named executive officers have been retirement eligible for several years and therefore their options will vest in full upon termination. Accordingly, under SFAS No. 123R, the full grant fair value of their option awards is expensed in the year of grant. However, for Mss. Story and Terry and Messrs. Raymond and McCullough, the amounts reported reflect the amounts expensed in 2008 attributable to the following stock option grants made in 2008 and in prior years because each of these named executive officers was not retirement eligible on the grant dates. Therefore, the grant date fair value for options granted to Mss. Story and Terry and Messrs. Raymond and McCullough is recognized over the shorter period of a) the vesting period of each option or b) the period to the date they become retirement eligible. The grant date fair value for the grant made in 2008 is reported in the Grants of Plan-Based Awards Table.

	Amount Expensed in 2008 ($)			
Grant Date	**S. N. Story**	**P. C. Raymond**	**T. J. McCullough**	**B. C. Terry**
2005	6,718	1,650	953	1,678
2006	57,192	12,292	7,070	12,322
2007	60,809	14,025	7,490	12,876
2008	45,817	10,709	6,027	8,875
TOTAL	170,536	38,676	21,540	35,751

Column (g)

The amounts in this column are the aggregate of the payouts under the annual incentive program and the performance dividend program attributable to performance periods ending December 31, 2008 that are discussed in detail in the CD&A. The amounts paid under each program to the named executive officers are shown below:

Name	**Annual Incentive ($)**	**Performance Dividends ($)**	**Total ($)**
S. N. Story	292,310	216,757	509,067
R. R. Labrato	168,021	100,838	268,859
P. C. Raymond	126,586	54,620	181,206
P. B. Jacob	127,496	53,655	181,151
T. J. McCullough	98,073	41,864	139,937
B. C. Terry	126,438	40,547	166,985

- Column (h)

This column reports the aggregate change in the actuarial present value of each named executive officer's accumulated benefit under the Pension Plan and the supplemental pension plans (collectively, Pension Benefits) during 2006, 2007 and 2008. The amount included for 2006 is the difference between the actuarial present values of the Pension Benefits measured as of September 30, 2005 and September 30, 2006 and the 2007 amount is the difference in the actuarial present values of the Pension Benefits measured as of September 30, 2006 and September 30, 2007. However, the amount for 2008 is the difference between the actuarial values of the Pension Benefits measured as of September 30, 2007 and December 31, 2008 - 15 months rather than one year. September 30 was used as the measurement date prior to 2008, because it was the date as of which Southern Company measured its retirement benefit obligations for accounting purposes. Starting in 2008, Southern Company changed its measurement date to December 31 to comply with FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." The Pension Benefits as of each measurement date are based on the named executive officer's age, pay, and service accruals and the plan provisions applicable as of the measurement date. The actuarial present values as of each measurement date reflect the assumptions Gulf Power selected for FASB Statement No. 87, "Employers' Accounting for Pensions" cost purposes as of that measurement date; however, the named executive officers were assumed to remain employed at Gulf Power or other Southern Company subsidiary until their benefits commence at the pension plans' stated normal retirement date, generally age 65. As a result, the amounts in column (h) related to Pension Benefits represent the combined impact of several factors—growth in the named executive officer's Pension Benefits over the measurement year; impact on the total present values of one year shorter discounting period due to the named executive officer being one year closer to normal retirement; impact on the total present values attributable to changes in assumptions from measurement date to measurement date; and impact on the total present values attributable to plan changes between measurement dates.

The Pension Plans' provisions were substantively the same as of September 30, 2005 and September 30, 2006. However, the present values of accumulated Pension Benefits as of September 30, 2007 reflect new provisions regarding the form and timing of payments from the supplemental pension plans. These changes bring those plans into compliance with Section 409A of the Code. The key change was to the form of payment. Instead of providing monthly payments for the lifetime of each named executive officer and his/her spouse, these plans will pay the single sum value of those benefits for an average lifetime in 10 annual installments. Calculations of the present value of accumulated benefits calculations shown prior to September 30, 2007 reflect supplemental pension benefits being paid monthly for the lifetimes of named executive officers and their spouses. The 2007 change in pension value reported in column (h) for each named executive officer is greater than what it otherwise would have been due to the change in the form of payment.

For more information about the Pension Benefits and the assumptions used to calculate the actuarial present value of accumulated benefits as of December 31, 2008, see the information following the Pension Benefits Table. The key differences between assumptions used for the actuarial present values of accumulated benefits calculations as of September 30, 2007 and December 31, 2008 follow:

- Discount rate was increased to 6.75% as of December 31, 2008 from 6.3% as of September 30, 2007.
- 15-month measurement period, as described above.

This column also reports above-market earnings on deferred compensation under the Deferred Compensation Plan (DCP). There were no above-market earnings on deferred compensation in 2008. For more information about the DCP, see the Nonqualified Deferred Compensation Table and information accompanying it.

The table below itemizes the amounts reported in this column.

Name	Year	Change in Pension Value ($)	Above-Market Earnings on Deferred Compensation ($)	Total ($)
S. N. Story	**2008**	128,423	0	128,423
	2007	221,213	9,907	231,120
	2006	56,406	8,938	65,344
R. R. Labrato	**2008**	147,939	0	147,939
	2007	165,758	326	166,084
	2006	71,618	0	71,618
P. C. Raymond	**2008**	48,120	0	48,120
P. B. Jacob	**2008**	103,293	0	103,293
	2007	125,316	358	125,674
	2006	53,721	214	53,935
T. J. McCullough	**2008**	30,798	0	30,798
	2007	30,607	67	30,674
B. C. Terry	**2008**	13,845	0	13,845
	2007	13,729	73	13,802

Column (i)

This column reports the following items: perquisites; tax reimbursements by the employing company on certain perquisites; the employing company's contributions in 2008 to the Southern Company Employee Savings Plan (ESP), which is a tax-qualified defined contribution plan intended to meet requirements of Section 401(k) of the Code; and the employing company's contributions in 2008 under the Southern Company Supplemental Benefit Plan (Non-Pension Related) (SBP). The SBP is described more fully in the information following the Nonqualified Deferred Compensation Table.

The amounts reported are itemized below.

Name	Perquisites ($)	Tax Reimbursements ($)	ESP ($)	SBP ($)	Total ($)
S. N. Story	13,225	5,963	11,730	8,191	39,109
R. R. Labrato	120,364	65,651	11,339	1,346	198,700
P. C. Raymond	30,014	3,422	11,010	0	44,446
P. B. Jacob	9,339	2,969	9,911	0	22,219
T. J. McCullough	62,074	7,430	9,216	0	78,720
B. C. Terry	9,993	6,327	9,930	0	26,250

Description of Perquisites

Personal Financial Planning is provided for most officers of Gulf Power, including all of the named executive officers. Gulf Power pays for the services of the financial planner on behalf of the officers, up to a maximum amount of $8,700 per year, after the initial year that the benefit is provided. In the initial year, the allowed amount is $15,000. The employing company also provides a five-year allowance of $6,000 for estate planning and tax return preparation fees.

Personal Use of Company-Provided Club Memberships. The employing company provides club memberships to certain officers, including all of the named executive officers. The memberships are provided for business use; however, personal use is permitted. The amount included reflects the pro-rata portion of the membership fees paid by the employing company that are attributable to the named executive officers' personal use. Direct costs associated with any personal use, such as meals, are paid for or reimbursed by the employee and therefore are not included.

Relocation Benefits. These benefits are provided to cover the costs associated with geographic relocation. In 2008, Messrs. Labrato, McCullough, and Raymond received relocation benefits in the amounts of $113,373, $23,344 and $25,650, respectively.

Personal Use of Corporate-Owned Aircraft. Southern Company owns aircraft that are used to facilitate business travel. All flights on these aircraft must have a business purpose. Also, if seating is available, Southern Company permits a spouse or other family member to accompany an employee on a flight. However, because in such cases the aircraft is being used for a business purpose, there is no incremental cost associated with the spousal travel and no amounts are included for such travel. Any additional expenses incurred that are related to spousal travel are included.

For Mr. McCullough, $31,708 of the $62,074 in 2008 represents the incremental cost of use of corporate-owned aircraft for relocation purposes. Mr. McCullough relocated from Athens, Georgia to Pensacola, Florida and was permitted to travel to and from his home in Athens for a period of time in late 2007 through early 2008. For Mr. Raymond, $1,232 of $30,014 in 2008 represents the incremental cost of use of corporate-owned aircraft for relocation purposes. Mr. Raymond is relocating from Birmingham, Alabama to Pensacola, Florida. The incremental costs reported are the fuel costs for relocation flights plus any incidental costs incurred, such as associated hotel and meal expenses for pilots.

Home Security Systems. Gulf Power pays for the services of third-party providers for the installation, maintenance, and monitoring of Ms. Story's home security system.

Other Miscellaneous Perquisites. The amount included reflects the full cost to Gulf Power of providing the following items: personal use of company provided tickets for sporting and other entertainment events, and gifts distributed to and activities provided to attendees at company-sponsored events.

GRANTS OF PLAN-BASED AWARDS MADE IN 2008

The Grants of Plan-Based Awards Table provides information on stock option grants made and goals established for future payouts under Gulf Power's incentive compensation programs during 2008 by the Compensation Committee. In this table, the annual incentive and the performance dividend payouts are referred to as PPP and PDP, respectively.

			Estimated Possible Payouts Under Non-Equity Incentive Plan Awards			All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/Sh)	Closing Price on Last Trading Date Prior to Grant Date ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($)
Name (a)	Grant Date (b)		Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	(f)	(g)	(h)	(i)
S. N. Story	2/18/2008	PPP	106,943	237,650	522,831	43,406	35.78	35.78	102,872
		PDP	13,860	138,599	277,199				
R. R. Labrato	2/18/2008	PPP	53,156	118,125	259,875	16,181	35.78	35.78	38,349
		PDP	6,448	64,478	128,957				
P. C. Raymond	2/18/2008	PPP	44,921	99,825	219,615	8,980	35.78	35.78	21,283
		PDP	3,492	34,925	69,850				
P. B. Jacob	2/18/2008	PPP	46,645	103,656	228,043	13,785	35.78	35.78	32,670
		PDP	3,431	34,308	68,616				
T. J. McCullough	2/18/2008	PPP	32,935	73,189	161,016	8,772	35.78	35.78	20,790
		PDP	2,677	26,769	53,537				
B. C. Terry	2/18/2008	PPP	46,258	102,795	226,149	12,918	35.78	35.78	30,616
		PDP	2,593	25,927	51,853				

Columns (c), (d), and (e)

The amounts reported as PPP reflect the amounts established by the Compensation Committee in early 2008 to be paid for certain levels of performance as of December 31, 2008 under the annual incentive program. The Compensation Committee assigns each named executive officer a target incentive opportunity, expressed as a percentage of base salary, that is paid for target-level performance under the annual incentive program. The target incentive opportunities established for the named executive officers for 2008 performance were 60% for Ms. Story, 45% for Ms. Terry and Messrs. Labrato, Jacob, and Raymond, and 40% for Mr. McCullough. Due to a change in job assignment in 2008, the target incentive opportunity for Mr. Raymond was 40% for a portion of 2008. The payout for threshold performance was set at 0.45 times the target incentive opportunity and the maximum amount payable was set at 2.20 times the target. The amount paid to each named executive officer under the annual incentive program for actual 2008 performance is included in the Non-Equity Incentive Plan Compensation column in the Summary Compensation Table and is itemized in the notes following that table. More information about the annual incentive program, including the applicable performance criteria established by the Compensation Committee, is provided in the CD&A.

Southern Company also has a long-term incentive program, the performance dividend program, that has been adopted by Gulf Power and SCS. It pays performance-based dividend equivalents based on Southern Company's total shareholder return (TSR) compared with the TSR of its peer companies over a four-year performance-measurement period. The Compensation Committee establishes the level of payout for prescribed levels of performance over the performance-measurement period.

In February 2008, the Compensation Committee established the performance dividend program goal for the four-year performance-measurement period beginning on January 1, 2008 and ending on December 31, 2011. The amount earned in 2011 based on the performance for 2008-2011 will be paid following the end of the period. However, no amount is earned and paid unless the Compensation Committee approves the payment at the beginning of the final year of the performance-measurement period. Also, nothing is earned unless Southern Company's earnings are sufficient to fund a Common Stock dividend at least equal to that paid in the prior year.

The performance dividend program pays to all option holders a percentage of the Common Stock dividend paid to Southern Company's stockholders in the last year of the performance-measurement period. It can range from approximately five percent for performance above the 10th percentile compared with the performance of the peer companies to 100% of the dividend if Southern Company's TSR is at or above the 90th percentile. That amount is then paid per option held at the end of the four-year period. The amount, if any, ultimately paid to the option holders, including the named executive officers, at the end of the last year of the 2008-2011 performance-measurement period will be based on (1) Southern Company's TSR compared to that of its peer companies as of December 31, 2011, (2) the actual dividend paid in 2011 to Southern Company's stockholders, if any, and (3) the number of options held by the named executive officers on December 31, 2011.

The number of options held on December 31, 2011 will be affected by the number of additional options granted to the named executive officers prior to December 31, 2011, if any, and the number of options exercised by the named executive officers prior to December 31, 2011, if any. None of these components necessary to calculate the range of payout under the performance dividend program for the 2008-2011 performance-measurement period is known at the time the goal is established.

The amounts reported as PDP in columns (c), (d), and (e) were calculated based on the number of options held by the named executive officers on December 31, 2008, as reported in columns (b) and (c) of the Outstanding Equity Awards at Fiscal Year-End Table and the Common Stock dividend of $1.6625 per share paid to Southern Company's stockholders in 2008. These factors are itemized below.

Name	Stock Options Held as of December 31, 2008 (#)	Performance Dividend Per Option Paid at Threshold Performance ($)	Performance Dividend Per Option Paid at Target Performance ($)	Performance Dividend Per Option Paid at Maximum Performance ($)
S. N. Story	166,736	0.083125	0.83125	1.6625
R. R. Labrato	77,568	0.083125	0.83125	1.6625
P. C. Raymond	42,015	0.083125	0.83125	1.6625
P. B. Jacob	41,273	0.083125	0.83125	1.6625
T. J. McCullough	32,203	0.083125	0.83125	1.6625
B. C. Terry	31,190	0.083125	0.83125	1.6625

More information about the PDP is provided in the CD&A.

Columns (f), (g), and (h)

The stock options vest at the rate of one-third per year, on the anniversary date of the grant. Also, grants fully vest upon termination as a result of death, total disability, or retirement and expire five years after retirement, three years after death or total disability, or their normal expiration date if earlier. Please see Potential Payments Upon Termination or Change-in-Control for more information about the treatment of stock options under different termination and change-in-control events.

The Compensation Committee granted these stock options to the named executive officers at its regularly-scheduled meeting on February 18, 2008. Under the terms of the Omnibus Incentive Compensation Plan, the exercise price was set at the closing price ($35.78 per share) on the last trading day prior to the grant date which was February 15, 2008.

Column (i)

The value of stock options granted in 2008 was derived using the Black-Scholes stock option pricing model. The assumptions used in calculating these amounts are discussed in Note 8 to the financial statements of Gulf Power in Item 8 herein.

OUTSTANDING EQUITY AWARDS AT 2008 FISCAL YEAR-END

This table provides information pertaining to all outstanding stock options held by the named executive officers as of December 31, 2008.

	Option Awards					Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Number of Securities Underlying Unexercised Options (#) Unexercisable	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)
S. N. Story	38,529	0	0	32.70	02/18/2015	0	0	0	0
	27,553	13,776		33.81	02/20/2016				
	14,491	28,981		36.42	02/19/2017				
	0	43,406		35.78	02/18/2018				
R. R. Labrato	15,646	0	0	29.50	02/13/2014	0	0	0	0
	15,707	0		32.70	02/18/2015				
	9,735	4,867		33.81	02/20/2016				
	5,144	10,288		36.42	02/19/2017				
	0	16,181		35.78	02/18/2018				
P. C. Raymond	1,230	0	0	27.975	02/14/2013	0	0	0	0
	4,196	0		29.50	02/13/2014				
	9,463	0		32.70	02/18/2015				
	5,921	2,961		33.81	02/20/2016				
	3,088	6,176		36.42	02/19/2017				
	0	8,980		35.78	02/18/2018				
P. B. Jacob	4,738	0	0	32.70	02/18/2015	0	0	0	0
	4,412	4,413		33.81	02/20/2016				
	4,642	9,283		36.42	02/19/2017				
	0	13,785		35.78	02/18/2018				
T. J. McCullough	1,985	0	0	27.975	02/14/2013	0	0	0	0
	5,421	0		29.50	02/13/2014				
	5,468	0		32.70	02/18/2015				
	3,405	1,703		33.81	02/20/2016				
	1,817	3,632		36.42	02/19/2017				
	0	8,772		35.78	02/18/2018				
B. C. Terry	5,937	2,968	0	33.81	02/20/2016	0	0	0	0
	3,123	6,244		36.42	02/19/2017				
	0	12,918		35.78	02/18/2018				

Stock options vest one-third per year on the anniversary of the grant date. Options granted from 2002 through 2005 with expiration dates from 2012 through 2015 were fully vested as of December 31, 2008. The options granted in 2006, 2007, and 2008 become fully vested as shown below.

Year Option Granted	Expiration Date	Date Fully Vested
2006	February 20, 2016	February 20, 2009
2007	February 19, 2017	February 19, 2010
2008	February 18, 2018	February 18, 2011

Options also fully vest upon death, total disability, or retirement and expire three years following death or total disability or five years following retirement, or on the original expiration date if earlier. Please see Potential Payments Upon Termination or Change-in-Control for more information about the treatment of stock options under different termination and change-in-control events.

OPTION EXERCISES AND STOCK VESTED IN 2008

None of the named executive officers were granted Stock Awards.

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#) (d)	Value Realized on Vesting ($) (e)
S. N. Story	37,837	218,149	0	0
R. R. Labrato	11,530	138,648	0	0
P. C. Raymond	0	0	0	0
P. B. Jacob	0	0	0	0
T. J. McCullough	3,596	45,400	0	0
B. C. Terry	9,625	42,559	0	0

PENSION BENEFITS AT 2008 FISCAL YEAR-END

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
S. N. Story	Pension Plan	26.00	348,397	0
	SBP-P	26.00	589,275	0
	SERP	26.00	238,648	0
R. R. Labrato	Pension Plan	28.75	579,765	0
	SBP-P	28.75	276,849	0
	SERP	28.75	183,696	0
P. C. Raymond	Pension Plan	17.00	191,680	0
	SBP-P	17.00	60,181	0
	SERP	17.00	52,713	0
P. B. Jacob	Pension Plan	25.42	448,190	0
	SBP-P	25.42	173,149	0
	SERP	25.42	131,237	0
T. J. McCullough	Pension Plan	20.75	167,610	0
	SBP-P	20.75	31,768	0
	SERP	20.75	41,183	0
B. C. Terry	Pension Plan	6.50	40,633	0
	SBP-P	6.50	10,863	0
	SERP	6.50	12,620	0

The named executive officers earn employer-paid pension benefits from three integrated retirement plans. More information about pension benefits is provided in the CD&A.

The Pension Plan

The Pension Plan is a tax-qualified, funded plan. It is Southern Company's primary retirement plan. Generally, all full-time employees participate in this plan after one year of service. Normal retirement benefits become payable when participants both attain age 65 and complete five years of participation. The plan benefit equals the greater of amounts computed using a "1.7% offset formula" and a "1.25% formula," as described below. Benefits are limited to a statutory maximum.

The 1.7% offset formula amount equals 1.7% of final average pay times years of participation less an offset related to Social Security benefits. The offset equals a service ratio times 50% of the anticipated Social Security benefits in excess of $4,200. The service ratio adjusts the offset for the portion of a full career that a participant has worked. The highest three rates of pay out of a participant's last 10 calendar years of service are averaged to derive final average pay. The pay considered for this formula is the base rate of pay reduced for any voluntary deferrals. A statutory limit restricts the amount considered each year; the limit for 2008 was $230,000.

The 1.25% formula amount equals 1.25% of final average pay times years of participation. For this formula, the final average pay computation is the same as above, but annual cash incentives paid during each year are added to the base rates of pay.

Early retirement benefits become payable once plan participants have during employment both attained age 50 and completed 10 years of participation. Participants who retire early from active service receive benefits equal to the amounts computed using the same formulas employed at normal retirement. However, a 0.3% reduction applies for each month (3.6% for each year) prior to normal retirement that participants elect to have their benefit payments commence. For example, 64% of the formula benefits are payable starting at age 55. As of December 31, 2008, only Messrs. Labrato and Jacob were eligible to retire immediately.

The Pension Plan's benefit formulas produce amounts payable monthly over a participant's post-retirement lifetime. At retirement, plan participants can choose to receive their benefits in one of seven alternative forms of payment. All forms pay benefits monthly over the lifetime of the retiree or the joint lifetimes of the retiree and a spouse. A reduction applies if a retiring participant chooses a payment form other than a single life annuity. The reduction makes the value of the benefits paid in the form chosen comparable to what it would have been if benefits were paid as a single life annuity over the retiree's life.

Participants vest in the Pension Plan after completing five years of service. All the named executive officers are vested in their Pension Plan benefits. Participants who terminate employment after vesting can elect to have their pension benefits commencing at age 50 if they participated in the Pension Plan for 10 years. If such an election is made, the early retirement reductions that apply are actuarially determined factors and are larger than 0.3% per month.

If a participant dies while actively employed, benefits will be paid to a surviving spouse. A survivor's benefit equals 45% of the monthly benefit that the participant had earned before his or her death. Payments to a surviving spouse of a participant who could have retired will begin immediately. Payments to a survivor of a participant who was not retirement eligible will begin when the deceased participant would have attained age 50. After commencing, survivor benefits are payable monthly for the remainder of a survivor's life. Participants who are eligible for early retirement may opt to have an 80% survivor benefit paid if they die; however, there is a charge associated with this election.

If participants become totally disabled, periods that Social Security or employer provided disability income benefits are paid will count as service for benefit calculation purposes. The crediting of this additional service ceases at the point a disabled participant elects to commence retirement payments. Outside of the extra service crediting, the normal plan provisions apply to disabled participants.

The Southern Company Supplemental Benefit Plan (Pension-Related) (SBP-P)

The SBP-P is an unfunded retirement plan that is not tax qualified. This plan provides to high-paid employees any benefits that the Pension Plan cannot pay due to statutory pay/benefit limits and voluntary pay deferrals. The SBP-P's vesting, early retirement, and disability provisions mirror those of the Pension Plan.

The amounts paid by the SBP-P are based on the additional monthly benefit that the Pension Plan would pay if the statutory limits and pay deferrals were ignored. When an SBP-P participant separates from service, vested monthly benefits provided by the benefit formulas are converted into a single sum value. It equals the present value of what would have been paid monthly for an actuarially determined average post-retirement lifetime. The discount rate used in the calculation is based on the 30-year Treasury yields for the September preceding the calendar year of separation, but not more than six percent. Vested participants terminating prior to becoming eligible to retire will be paid their single sum value as of September 1 following the calendar year of separation. If the terminating participant is retirement eligible, the single sum value will be paid in 10 annual installments starting shortly after separation. The unpaid balance of a retiree's single sum will be credited with interest at the prime rate published in The Wall Street Journal. If the separating participant is a "key man" under Section 409A of the Code, the first installment will be delayed for six months after the date of separation.

If an SBP-P participant dies after becoming vested in the Pension Plan, the spouse of the deceased participant will receive the installments the participant would have been paid upon retirement. If a vested participant's death occurs prior to age 50, the installments will be paid to a survivor as if the participant had survived to age 50.

The Southern Company Supplemental Executive Retirement Plan (SERP)

The SERP also is an unfunded retirement plan that is not tax qualified. This plan provides to high paid employees additional benefits that the Pension Plan and the SBP-P would pay if the 1.7% offset formula calculations reflected a portion of annual cash incentives. To derive the SERP benefits, a final average pay is determined reflecting participants' base rates of pay and their incentives to the extent they exceed 15% of those base rates (ignoring statutory limits and pay deferrals). This final average pay is used in the 1.7% offset formula to derive a gross benefit. The Pension Plan and the SBP-P benefits are subtracted from the gross benefit to calculate the SERP benefit. The SERP's early retirement, survivor benefit, and disability provisions mirror the SBP-P's provisions. However, except upon a change-in-control, SERP benefits do not vest until participants retire, so no benefits are paid if a participant terminates prior to becoming eligible to retire. More information about vesting and payment of SERP benefits following a change-in-control is included in the section entitled Potential Payments Upon Termination or Change-in-Control.

The following assumptions were used in the present value calculations:

- Discount rate – 6.75% as of December 31, 2008
- Retirement date – Normal retirement age (65 for all named executive officers)
- Mortality after normal retirement — RP2000 Combined Healthy with generational projections
- Mortality, withdrawal, disability and retirement rates prior to normal retirement — None
- Form of payment for Pension Benefits
    - Unmarried retirees: 100% elect a single life annuity
    - Married retirees: 20% elect a single life annuity; 40% elect a joint and 50% survivor annuity; and 40% elect a joint and 100% survivor annuity
- Percent married at retirement — 80% of males and 70% of females
- Spouse ages — Wives two years younger than their husbands
- Incentives earned but unpaid as of the measurement date — 135% of target percentages times base rate of pay for year incentive is earned.
- Installment determination—4.75% discount rate for single sum calculation and 6.75% prime rate during installment payment period

For all of the named executive officers, the number of years of credited service is one year less than the number of years of employment.

NONQUALIFIED DEFERRED COMPENSATION AS OF 2008 FISCAL YEAR-END

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
S. N. Story	0	8,191	56,719	0	1,561,209
R. R. Labrato	44,153	1,346	4,228	0	106,305
P. C. Raymond	0	0	0	0	497
P. B. Jacob	15,943	0	2,878	0	66,086
T. J. McCullough	9,137	0	849	0	45,410
B. C. Terry	62,044	0	2,408	0	66,196

Southern Company provides the DCP which is designed to permit participants to defer income as well as certain federal, state, and local taxes until a specified date or their retirement, or other separation from service. Up to 50% of base salary and up to 100% of the annual incentive and performance dividends may be deferred, at the election of eligible employees. All of the named executive officers are eligible to participate in the DCP.

Participants have two options for the deemed investments of the amounts deferred – the Stock Equivalent Account and the Prime Equivalent Account. Under the terms of the DCP, participants are permitted to transfer between investments at any time.

The amounts deferred in the Stock Equivalent Account are treated as if invested at an equivalent rate of return to that of an actual investment in Common Stock, including the crediting of dividend equivalents as such are paid by Southern Company from time to time. It provides participants with an equivalent opportunity for the capital appreciation (or loss) and income held by a Southern Company stockholder. During 2008, the rate of return in the Stock Equivalent Account was 0.03%, which was Southern Company's TSR for 2008.

Alternatively, participants may elect to have their deferred compensation deemed invested in the Prime Equivalent Account which is treated as if invested at a prime interest rate compounded monthly, as published in the *Wall Street Journal* as the base rate on corporate loans posted as of the last business day of each month by at least 75% of the United States' largest banks. The range of interest rates earned on amounts deferred during 2008 in the Prime Equivalent Account was 3.25% to 6.0%.

Column (b)

This column reports the actual amounts of compensation deferred under the DCP by each named executive officer in 2008. The amount of salary deferred by the named executive officers, if any, is included in the Salary column in the Summary Compensation Table. The amount of incentive compensation deferred in 2008 was the amount paid for performance under the annual incentive program and the performance dividend program that were earned as of December 31, 2007 but not payable until the first quarter of 2008. This amount is not reflected in the Summary Compensation Table because that table reports incentive compensation that was earned in 2008, but not payable until early 2009. These deferred amounts may be distributed in a lump sum or in up to 10 annual installments at termination of employment or in a lump sum at a specified date, at the election of the participant.

Column (c)

This column reflects contributions under the SBP. Under the Code, employer matching contributions are prohibited under the ESP on employee contributions above stated limits in the ESP, and, if applicable, above legal limits set forth in the Code. The SBP is a nonqualified deferred compensation plan under which contributions are made that are prohibited from being made in the ESP. The contributions are treated as if invested in Common Stock and are payable in cash upon termination of employment in a lump sum or in up to 20 annual installments, at the election of the participant. The amounts reported in this column were also reported in the All Other Compensation column in the Summary Compensation Table.

Column (d)

This column reports earnings on both compensation the named executive officers elected to defer and earnings on employer contributions under the SBP. See the notes to column (h) of the Summary Compensation Table for a discussion of amounts of nonqualified deferred compensation earnings included in the Summary Compensation Table.

Column (f)

This column includes amounts that were deferred under the DCP and contributions under the SBP in prior years and reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K. The chart below shows the amounts reported in Gulf Power's prior years' Information Statements or Annual Reports on Form 10-K.

Name	Amounts Deferred under the DCP Prior to 2008 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Employer Contributions under the SBP Prior to 2008 and Reported in Prior Years' Information Statements or Annual Reports on Form 10-K ($)	Total ($)
S. N. Story	18,373	258,601	276,974
R. R. Labrato	47,951	313	48,264
P. C. Raymond	0	0	0
P. B. Jacob	27,927	22,674	50,601
T. J. McCullough	9,516	0	9,516
B. C. Terry	59,383	0	59,383

POTENTIAL PAYMENTS UPON TERMINATION OR CHANGE-IN-CONTROL

This section describes and estimates payments that could be made to the named executive officers under different termination and change-in-control events. The estimated payments would be made under the terms of Southern Company's compensation and benefits programs or the change-in-control severance program. All of the named executive officers are participants in Southern Company's change-in-control severance plan for officers. (As described in the CD&A, all employees not part of a collective bargaining unit are participants in a change-in-control severance plan.) The amount of potential payments is calculated as if the triggering events occurred as of December 31, 2008 and assumes that the price of Common Stock is the closing market price on December 31, 2008.

Description of Termination and Change-in-Control Events

The following charts list different types of termination and change-in-control events that can affect the treatment of payments under the compensation and benefit programs. These events also affect payments to the named executive officers under their change-in-control severance agreements. No payments are made under the severance

agreements unless, within two years of the change-in-control, the named executive officer is involuntarily terminated or he or she voluntarily terminates for Good Reason. (See the description of Good Reason below.)

Traditional Termination Events

- Retirement or Retirement Eligible – Termination of a named executive officer who is at least 50 years old and has at least 10 years of credited service.
- Resignation – Voluntary termination of a named executive officer who is not retirement eligible.
- Lay Off – Involuntary termination of a named executive officer not for cause, who is not retirement eligible.
- Involuntary Termination – Involuntary termination of a named executive officer for cause. Cause includes individual performance below minimum performance standards and misconduct, such as violation of Gulf Power's Drug and Alcohol Policy.
- Death or Disability – Termination of a named executive officer due to death or disability.

Change-in-Control-Related Events

At the Southern Company or Gulf Power level:

- Southern Company Change-in-Control I – Acquisition by another entity of 20% or more of Common Stock, or following a merger with another entity Southern Company's stockholders own 65% or less of the entity surviving the merger.
- Southern Company Change-in-Control II – Acquisition by another entity of 35% or more of Common Stock, or following a merger with another entity Gulf Power's stockholders own less than 50% of Gulf Power surviving the merger.
- Southern Company Termination – A merger or other event and Southern Company is not the surviving company or the Common Stock is no longer publicly traded.
- Gulf Power Change-in-Control – Acquisition by another entity, other than another subsidiary of Southern Company, of 50% or more of the stock of Gulf Power, a merger with another entity and Gulf Power is not the surviving company, or the sale of substantially all the assets of Gulf Power.

At the employee level:

- Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason – Employment is terminated within two years of a change-in-control, other than for cause, or the employee voluntarily terminates for Good Reason. Good Reason for voluntary termination within two years of a change-in-control is generally satisfied when there is a material reduction in salary, incentive compensation opportunity or benefits, relocation of over 50 miles, or a diminution in duties and responsibilities.

The following chart describes the treatment of different pay and benefit elements in connection with the Traditional Termination Events described above.

Program	Retirement/ Retirement Eligible	Lay Off (Involuntary Termination Not For Cause)	Resignation	Death or Disability	Involuntary Termination (For Cause)
Pension Benefits Plans	Benefits payable as described in the notes following the Pension Benefits Table.	Same as Retirement.	Same as Retirement.	Same as Retirement.	Same as Retirement.
Annual Incentive Program	Pro-rated if terminate before 12/31.	Same as Retirement.	Forfeit.	Same as Retirement.	Forfeit.
Performance Dividend Program	Paid year of retirement plus two additional years.	Forfeit.	Forfeit.	Payable until options expire or exercised.	Forfeit.
Stock Options	Vest; expire earlier of original expiration date or five years.	Vested options expire in 90 days; unvested are forfeited.	Same as Lay Off.	Vest; expire earlier of original expiration or three years.	Forfeit.
Financial Planning Perquisite	Continues for one year.	Terminates.	Terminates.	Same as Retirement.	Terminates.
Deferred Compensation Plan	Payable per prior elections (lump sum or up to 10 annual installments).	Same as Retirement.	Same as Retirement.	Payable to beneficiary or disabled participant per prior elections; amounts deferred prior to 2005 can be paid as a lump sum per benefit administration committee's discretion.	Same as Retirement.
Supplemental Benefit Plan – non-pension related	Payable per prior elections (lump sum or up to 20 annual installments).	Same as Retirement.	Same as Retirement.	Same as the Deferred Compensation Plan.	Same as Retirement.

The chart below describes the treatment of payments under pay and benefit programs under different change-in-control events, except the Pension Plan. The Pension Plan is not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change-in-Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Nonqualified Pension Benefits	All SERP-related benefits vest if participants vested in tax-qualified pension benefits; otherwise, no impact.	Benefits vest for all participants and single sum value of benefits earned to the change-in-control date paid following termination or retirement.	Same as Southern Company Change-in-Control II.	Based on type of change-in-control event.
Annual Incentive	No plan termination is paid at greater of target or actual performance. If plan terminated within two years of change-in-control, pro-rated at target performance level.	Same as Southern Company Change-in-Control I.	Pro-rated at target performance level.	If not otherwise eligible for payment, if annual incentive still in effect, pro-rated at target performance level.
Performance Dividend	No plan termination is paid at greater of target or actual performance. If plan terminated within two years of change-in-control, pro-rated at greater of target or actual performance level.	Same as Southern Company Change-in-Control I.	Pro-rated at greater of actual or target performance level.	If not otherwise eligible for payment, if the performance dividend program is still in effect, greater of actual or target performance level for year of severance only.
Stock Options	Not affected by change-in-control events.	Not affected by change-in-control events.	Vest and convert to surviving company's securities; if cannot convert, pay spread in cash.	Vest.
DCP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.
SBP	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.	Not affected by change-in-control events.

Program	Southern Company Change-in-Control I	Southern Company Change-in-Control II	Southern Company Termination or Gulf Power Change-in-Control	Involuntary Change-in-Control-Related Termination or Voluntary Change-in-Control-Related Termination for Good Reason
Severance Benefits	Not applicable.	Not applicable.	Not applicable.	Two or three times base salary plus target annual incentive plus tax gross up for certain named executive officers if a severance amount exceeds the Code Section 280G - "excess parachute payment" by 10% or more.
Health Benefits	Not applicable.	Not applicable.	Not applicable.	Up to five years participation in group health plan plus payment of two or three years' premium amounts.
Outplacement Services	Not applicable.	Not applicable.	Not applicable.	Six months.

Potential Payments

This section describes and estimates payments that would become payable to the named executive officers upon a termination or change-in-control as of December 31, 2008.

Pension Benefits

The amounts that would have become payable to the named executive officers if the Traditional Termination Events occurred as of December 31, 2008 under the Pension Plan, the SBP-P, and the SERP are itemized in the chart below. The amounts shown under the column Retirement are amounts that would have become payable to the named executive officers that were retirement eligible on December 31, 2008 and are the monthly Pension Plan benefits and the first of 10 annual installments from the SBP-P and the SERP. The amounts shown under the column Resignation or Involuntary Termination are the amounts that would have become payable to the named executive officers who were not retirement eligible on December 31, 2008 and are the monthly Pension Plan benefits that would become payable as of the earliest possible date under the Pension Plan and the single sum value of benefits earned up to the termination date under the SBP-P, paid as a single payment rather than in 10 annual installments. Benefits under the SERP would be forfeited. The amounts shown that are payable to a spouse in the event of the death of the named executive officer are the monthly amounts payable to a spouse under the Pension Plan and the first of 10 annual installments from the SBP-P and the SERP. The amounts in this chart are very different from the pension values shown in the Summary Compensation Table and the Pension Benefits Table. Those tables show the present values of all the benefits amounts anticipated to be paid over the lifetimes of the named executive officers and their spouses. Those plans are described in the notes following the Pension Benefits Table. Of the named executive officers, only Messrs. Labrato and Jacob were retirement eligible on December 31, 2008.

Name		Retirement ($)	Resignation or Involuntary Termination ($)	Death (payments to a spouse) ($)
S. N. Story	Pension	n/a	2,185	3,588
	SBP-P		823,105	102,196
	SERP		0	41,388
R. R. Labrato	Pension	5,751	All plans treated as	3,845
	SBP-P	41,035	retiring	41,035
	SERP	27,228		27,228
P. C. Raymond	Pension	n/a	1,198	1,968
	SBP-P		83,802	10,324
	SERP		0	9,043
P. B. Jacob	Pension	4,500	All plans treated as	3,256
	SBP-P	26,605	retiring	26,605
	SERP	20,165		20,165
T. J. McCullough	Pension	n/a	1,331	2,185
	SBP-P		47,421	6,962
	SERP		0	9,026
B C. Terry	Pension	n/a	493	809
	SBP-P		18,299	3,680
	SERP		0	4,275

As described in the Change-in-Control Chart, the only change in the form of payment, acceleration, or enhancement of the pension benefits is that the single sum value of benefits earned up to the change-in-control date under the SBP-P and the SERP could be paid as a single payment rather than in 10 annual installments. Also, the SERP benefits vest for participants who are not retirement eligible upon a change-in-control. Estimates of the single sum payment that would have been made to the named executive officers, assuming termination as of December 31, 2008 following a change-in-control event, other than a Southern Company Change-in-Control I (which does not impact how pension benefits are paid), are itemized below. These amounts would be paid instead of the benefits shown in the Traditional Termination Events chart above; they are not paid in addition to those amounts.

Name	SBP-P ($)	SERP ($)	Total ($)
S. N. Story	800,944	324,370	1,125,314
R. R. Labrato	410,353	272,279	682,632
P. C. Raymond	81,546	71,427	152,973
P. B. Jacob	266,054	201,654	467,708
T. J. McCullough	46,144	59,820	105,964
B. C. Terry	17,807	20,686	38,493

The pension benefit amounts in the tables above were calculated as of December 31, 2008 assuming payments would begin as soon as possible under the terms of the plans. Accordingly, appropriate early retirement reductions were applied. Any unpaid incentives were assumed to be paid at 1.35 times the target level. Pension Plan benefits were calculated assuming each named executive officer chose a single life annuity form of payment, because that results in the greatest monthly benefit. The single sum values of the SBP-P and the SERP benefits were based on a 4.75% discount rate as prescribed by the terms of the plan.

Annual Incentive

Because this section assumes that a termination or change-in-control event occurred on December 31, 2008, there is no amount that would be payable other than what was reported and described in the Summary Compensation Table because actual performance in 2008 exceeded target performance.

Performance Dividends

Because the assumed termination date is December 31, 2008, there is no additional amount that would be payable other than what was reported in the Summary Compensation Table. As described in the Traditional Termination Events chart, there is some continuation of benefits under the performance dividend program for retirees.

However, under the Change-in-Control-Related Events, performance dividends are payable at the greater of target performance or actual performance. For the 2005-2008 performance-measurement period, actual performance was better than target performance.

Stock Options

Stock Options would be treated as described in the Termination and Change-in-Control charts above. Under a Southern Company Termination, all stock options vest. In addition, if there is an Involuntary Change-in-Control Termination or Voluntary Change-in-Control Termination for Good Reason, stock options vest. There is no payment associated with stock options unless there is a Southern Company Termination and the participants' stock options cannot be converted into surviving company stock options. In that event, the excess of the exercise price and the closing price of the Common Stock on December 31, 2008 would be paid in cash for all stock options held by the named executive officers. The chart below shows the number of stock options for which vesting would be accelerated under a Southern Company Termination and the amount that would be payable under a Southern Company Termination if there were no conversion to the surviving company's stock options.

Name	Number of Options with Accelerated Vesting (#)	Total Number of Options Following Accelerated Vesting under a Southern Company Termination (#)	Total Payable in Cash under a Southern Company Termination without Conversion of Stock Options ($)
S. N. Story	86,163	166,736	375,683
R. R. Labrato	31,336	77,568	260,157
P. C. Raymond	18,117	42,015	127,924
P. B. Jacob	27,481	41,273	73,419
T. J. McCullough	14,107	32,203	112,241
B. C. Terry	22,130	31,190	49,600

DCP and SBP

The aggregate balances reported in the Nonqualified Deferred Compensation Table would be payable to the named executive officers as described in the Traditional Termination and Change-in-Control-Related Events charts above. There is no enhancement or acceleration of payments under these plans associated with termination or change-in-control events, other than the lump-sum payment opportunity described in the above charts. The lump sums that would be payable are those that are reported in the Nonqualified Deferred Compensation Table.

Health Benefits

Messrs. Labrato and Jacob are retirement eligible and health care benefits are provided to retirees, and there is no incremental payment associated with the termination or change-in-control events. At the end of 2008, Mss. Story and Terry and Messrs. McCullough and Raymond were not retirement eligible and thus health care benefits would not become available until each reaches age 50, except in the case of a change-in-control-related termination, as described in the Change-in-Control-Related Events chart. The estimated cost of providing three years of group health insurance premiums for Ms. Story is $13,998 and two years for Ms. Terry is $8,925 and $20,227 each for Messrs. McCullough and Raymond.

Financial Planning Perquisite

Since Messrs. Labrato and Jacob are retirement eligible, an additional year of the Financial Planning perquisite, which is set at a maximum of $8,700 per year, will be provided after retirement. Mss. Story and Terry and Messrs. McCullough and Raymond are not retirement eligible.

There are no other perquisites provided to the named executive officers under any of the traditional termination or change-in-control-related events.

Severance Benefits

The named executive officers are participants in a change-in-control severance plan. In addition to the treatment of health benefits, the annual incentive program, and the performance dividend program described above, the named executive officers are entitled to a severance benefit, including outplacement services, if within two years of a change-in-control, they an involuntarily terminated, not for Cause, or they voluntarily terminate for Good Reason. The severance benefits are not paid unless the named executive officer releases the employing company from any claims he or she may have against the employing company.

The estimated cost of providing the six months of outplacement services is $6,000 per named executive officer. The severance payment is three times the base salary and target payout under the annual incentive program for Ms. Story and two times the base salary and target payout under the annual incentive program for the other named executive officers. If any portion of the severance payment is an "excess parachute payment" as defined under Section 280G of the Code, the employing company will pay the named executive officer an additional amount to cover the taxes that would be due on the excess parachute payment – a "tax gross-up." However, that additional amount will not be paid unless the severance amount plus all other amounts that are considered parachute payments under the Code exceed 110% of the severance payment.

The table below estimates the severance payments that would be made to the named executive officers if they were terminated as of December 31, 2008 in connection with a change-in-control. There is no estimated tax gross-up included for any of the named executive officers because their respective estimated severance amounts payable are below the amounts considered excess parachute payments under the Code.

Name	Severance Amount ($)
S. N. Story	1,901,203
R. R. Labrato	761,250
P. C. Raymond	662,456
P. B. Jacob	668,003
T. J. McCullough	512,324
B. C. Terry	662,456

DIRECTOR COMPENSATION

Only non-employee directors of Gulf Power are compensated for service on the board of directors. The pay components for non-employee directors are:

Annual retainers:

- $12,000 annual retainer

Equity grants:

- 340 shares of Common Stock in quarterly grants of 85 shares

Meeting fees:

- $1,200 for participation in a meeting of the board
- $1,000 for participation in a meeting of a committee of the board

DIRECTOR DEFERRED COMPENSATION PLAN

Any deferred quarterly equity grants are required to be deferred in the Deferred Compensation Plan For Directors of Gulf Power Company (Director Deferred Compensation Plan) and are invested in Common Stock units which earn dividends as if invested in Common Stock. Earnings are reinvested in additional stock units. Upon leaving the board, distributions are made in shares of Common Stock.

In addition, directors may elect to defer up to 100% of their remaining compensation in the Director Deferred Compensation Plan until membership on the board ends. Deferred compensation may be invested as follows, at the director's election:

- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in shares of Common Stock upon leaving the board
- in Common Stock units which earn dividends as if invested in Common Stock and are distributed in cash upon leaving the board
- at prime interest which is paid in cash upon leaving the board

All investments and earnings in the Director Deferred Compensation Plan are fully vested and, at the election of the director, may be distributed in a lump sum payment or in up to 10 annual distributions after leaving the board.

DIRECTOR COMPENSATION TABLE

The following table reports all compensation to Gulf Power's non-employee directors during 2008, including amounts deferred in the Director Deferred Compensation Plan. Non-employee directors do not receive Non-Equity Incentive Plan Compensation, and there is no pension plan for non-employee directors.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($)(3)	All Other Compensation ($)(4)	Total ($)
C. LeDon Anchors	17,800	18,536	0	123	36,459
William C. Cramer, Jr.	0	36,336	0	421	36,757
Fred C. Donovan, Sr.	0	36,336	0	123	36,459
William A. Pullum	0	36,336	0	123	36,459
Winston E. Scott	36,294	0	0	123	36,417

(1) Includes amounts voluntarily deferred in the Director Deferred Compensation Plan.
(2) Includes fair market value of equity grants on grant dates. All such stock awards are vested immediately upon grant.
(3) Above-market earnings on amounts invested in the Director Deferred Compensation Plan. Above-market earnings are defined by the SEC as any amount above 120% of the applicable federal long-term rate as prescribed under Section 1274(d) of the Code.
(4) Consists of reimbursement for taxes on imputed income associated with gifts.

COMPENSATION COMMITTEE INTERLOCKS AND INSIDER PARTICIPATION

The Compensation Committee is made up of non-employee directors of Southern Company who have never served as executive officers of Southern Company or Gulf Power. During 2008, none of Southern Company's or Gulf Power's executive officers served on the board of directors of any entities whose directors or officers serve on the Compensation Committee.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership of Certain Beneficial Owners. Southern Company is the beneficial owner of 100% of the outstanding common stock of Gulf Power.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Southern Company 30 Ivan Allen Jr. Boulevard, N.W. Atlanta, Georgia 30308		100%
	Registrant:		
	Gulf Power	3,142,717	

Security Ownership of Management. The following tables show the number of shares of Common Stock owned by the directors, nominees, and executive officers as of December 31, 2008. It is based on information furnished by the directors, nominees, and executive officers. The shares owned by all directors, nominees, and executive officers as a group constitute less than one percent of the total number of shares outstanding on December 31, 2008.

		Shares Beneficially Owned Include:	
Name of Directors, Nominees, and Executive Officers	**Shares Beneficially Owned (1)**	**Deferred Stock Units (2)**	**Shares Individuals Have Rights to Acquire Within 60 Days (3)**
Susan N. Story	129,225	0	42,735
C. LeDon Anchors	6,365	4,912	0
William C. Cramer, Jr.	7,566	7,566	0
Fred C. Donovan, Sr.	4,943	4,943	0
William A. Pullum	8,835	8,835	0
Winston E. Scott	611	0	0
P. Bernard Jacob	33,061	0	13,649
Theodore J. McCullough	24,764	0	6,443
Philip C. Raymond	35,155	0	9,043
Bentina C. Terry	19,837	0	10,396
Directors, Nominees, and Executive Officers as a group (10 people)	270,362	26,256	82,266

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security and/or investment power with respect to a security or any combination thereof.
(2) Indicates the number of deferred stock units held under the Director Deferred Compensation Plan.
(3) Indicates shares of Common Stock that certain executive officers have the right to acquire within 60 days. Shares indicated are included in the Shares Beneficially Owned column.

Changes in Control. Southern Company and Gulf Power know of no arrangements which may at a subsequent date result in any change-in-control.

Equity Compensation Plan Information

The following table provides information as of December 31, 2008 concerning shares of Common Stock authorized for issuance under Southern Company's existing non-qualified equity compensation plans.

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants, and rights (a)	Weighted-average exercise price of outstanding options, warrants, and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	36,952,419	$32.09	34,843,588
Equity compensation plans not approved by security holders	n/a	n/a	n/a

(1) Includes shares available for future issuances under the Omnibus Incentive Compensation Plan, the 2006 Omnibus Incentive Compensation Plan, and the Outside Directors Stock Plan.

(2) Includes shares available for future issuance under the 2006 Omnibus Incentive Compensation Plan (33,222,128) and the Outside Directors Stock Plan (1,621,460).

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

Transactions with Related Persons.

In 2008, Gulf Power paid $120,042 to Baskerville-Donovan, Inc. for architectural and design services. Mr. Donovan, a director of Gulf Power, is the chairman and chief executive officer of Baskerville-Donovan, Inc.

Review, Approval or Ratification of Transactions with Related Persons.

Gulf Power does not have a written policy pertaining solely to the approval or ratification of "related party transactions." Southern Company has a Code of Ethics as well as a Contract Guidance Manual and other formal written procurement policies and procedures that guide the purchase of goods and services, including requiring competitive bids for most transactions above $10,000 or approval based on documented business needs for sole sourcing arrangements.

Promoters and Certain Control Persons.

None.

Director Independence.

The board of directors of Gulf Power consists of five non-employee directors (Messrs. C. LeDon Anchors, William C. Cramer, Jr., Fred C. Donovan, Sr., William A. Pullum, and Winston E. Scott) and Ms. Story, the president and chief executive officer of Gulf Power.

Southern Company owns all of Gulf Power's outstanding common stock, which represents a substantial majority of the overall voting power of Gulf Power's equity securities, and Gulf Power has listed only debt securities on the NYSE. Accordingly, under the rules of the NYSE, Gulf Power is exempt from most of the NYSE's listing standards relating to corporate governance, including requirements relating to certain board committees. Gulf Power has voluntarily complied with certain of the NYSE's listing standards relating to corporate governance where such compliance was deemed to be in the best interests of Gulf Power's shareholders.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following represents the fees billed to Gulf Power and Southern Power for the last two fiscal years by Deloitte & Touche LLP, each company's principal public accountant for 2008 and 2007:

	2008	2007
	(in thousands)	
Gulf Power		
Audit Fees (1)	$1,324	$1,113
Audit-Related Fees (2)	0	27
Tax Fees	0	0
All Other Fees	0	0
Total	$1,324	$1,140
Southern Power		
Audit Fees (1)	$943	$1,016
Audit-Related Fees (2)	0	64
Tax Fees	0	0
All Other Fees	0	0
Total	$943	$1,080

(1) Includes services performed in connection with financing transactions.
(2) Includes other non-statutory audit services and accounting consultations.

The Southern Company Audit Committee (on behalf of Southern Company and its subsidiaries) adopted a Policy of Engagement of the Independent Auditor for Audit and Non-Audit Services that includes requirements for such Audit Committee to pre-approve audit and non-audit services provided by Deloitte & Touche LLP. All of the audit services provided by Deloitte & Touche LLP in fiscal years 2008 and 2007 (described in the footnotes to the table above) and related fees were approved in advance by the Southern Company Audit Committee.

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PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as a part of this report on Form 10-K:

(1) Financial Statements:

Management's Report on Internal Control Over Financial Reporting for Southern Company and Subsidiary Companies is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Alabama Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Georgia Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Gulf Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Mississippi Power is listed under Item 8 herein.

Management's Report on Internal Control Over Financial Reporting for Southern Power and Subsidiary Companies is listed under Item 8 herein.

Reports of Independent Registered Public Accounting Firm on the financial statements for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.

The financial statements filed as a part of this report for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power and Subsidiary Companies are listed under Item 8 herein.

(2) Financial Statement Schedules:

Reports of Independent Registered Public Accounting Firm as to Schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are included herein on pages IV-8, IV-9, IV-10, IV-11, and IV-12.

Financial Statement Schedules for Southern Company and Subsidiary Companies, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power are listed in the Index to the Financial Statement Schedules at page S-1.

(3) Exhibits:

Exhibits for Southern Company, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and Southern Power are listed in the Exhibit Index at page E-1.

THE SOUTHERN COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

THE SOUTHERN COMPANY

By: David M. Ratcliffe
Chairman, President, and
Chief Executive Officer

By:
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

David M. Ratcliffe
Chairman, President,
Chief Executive Officer, and Director
(Principal Executive Officer)

W. Paul Bowers
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

W. Ron Hinson
Comptroller and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Juanita Powell Baranco	*Warren A. Hood, Jr.*
Francis S. Blake	*Donald M. James*
Jon A. Boscia	*J. Neal Purcell*
Thomas F. Chapman	*William G. Smith, Jr.*
H. William Habermeyer, Jr.	*Gerald J. St. Pé*
Veronica M. Hagen	

By:
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

ALABAMA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

ALABAMA POWER COMPANY

By: Charles D. McCrary
President and Chief Executive Officer

By:
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Charles D. McCrary
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Art P. Beattie
Executive Vice President, Chief Financial Officer, and Treasurer
(Principal Financial Officer)

Moses H. Feagin
Vice President and Comptroller
(Principal Accounting Officer)

Directors:

Whit Armstrong	*Malcolm Portera*
Ralph D. Cook	*Robert D. Powers*
David J. Cooper, Sr.	*David M. Ratcliffe*
John D. Johns	*C. Dowd Ritter*
Patricia M. King	*James H. Sanford*
James K. Lowder	*John Cox Webb, IV*

By:
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

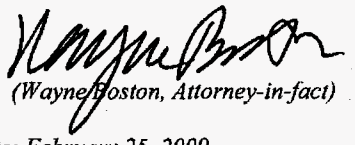
GEORGIA POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GEORGIA POWER COMPANY

By: Michael D. Garrett
President and Chief Executive Officer

By: 
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Michael D. Garrett
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Cliff S. Thrasher
Executive Vice President, Chief Financial Officer,
and Treasurer
(Principal Financial Officer)

Ann P. Daiss
Vice President, Comptroller, and Chief Accounting Officer
(Principal Accounting Officer)

Directors:

Robert L. Brown, Jr.	*D. Gary Thompson*
Anna R. Cablik	*Richard W. Ussery*
Stephen S. Green	*W. Jerry Vereen*
Jimmy C. Tallent	*E. Jenner Wood, III*
Beverly D. Tatum	

By:
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

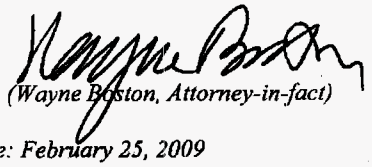
GULF POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

GULF POWER COMPANY

By: Susan N. Story
President and Chief Executive Officer

By: 
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Susan N. Story
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Philip C. Raymond
Vice President and Chief Financial Officer
(Principal Financial Officer)

Constance J. Erickson
Comptroller
(Principal Accounting Officer)

Directors:

C. LeDon Anchors	*William A. Pullum*
William C. Cramer, Jr.	*Winston E. Scott*
Fred C. Donovan, Sr.	

By:
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

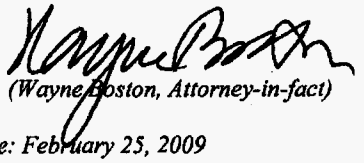
MISSISSIPPI POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

MISSISSIPPI POWER COMPANY

By: Anthony J. Topazi
President and Chief Executive Officer

By: 
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

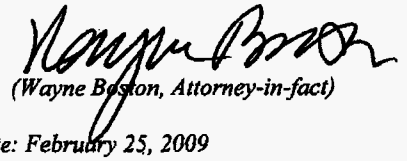
Anthony J. Topazi
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Frances Turnage
Vice President, Treasurer, and
Chief Financial Officer
(Principal Financial Officer)

Cindy F. Shaw
Comptroller
(Principal Accounting Officer)

Directors:

Roy Anderson, III	*Martha D. Saunders*
Tommy E. Dulaney	*George A. Schloegel*
Aubrey B. Patterson, Jr.	*Philip J. Terrell*
Christine L. Pickering	

By: 
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

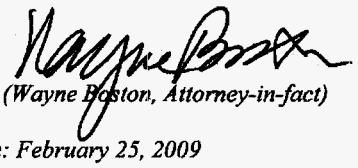
SOUTHERN POWER COMPANY

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

SOUTHERN POWER COMPANY

By: Ronnie L. Bates
President and Chief Executive Officer

By: 
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Ronnie L. Bates
President, Chief Executive Officer, and Director
(Principal Executive Officer)

Michael W. Southern
Senior Vice President and Chief Financial Officer
(Principal Financial Officer)

Laura I. Patterson
Comptroller
(Principal Accounting Officer)

Directors:

W. Paul Bowers	*G. Edison Holland, Jr.*
Thomas A. Fanning	*David M. Ratcliffe*

By:
(Wayne Boston, Attorney-in-fact)

Date: February 25, 2009

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Southern Company

We have audited the consolidated financial statements of Southern Company and Subsidiaries (the "Company") as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and the Company's internal control over financial reporting as of December 31, 2008, and have issued our report thereon dated February 25, 2009; such report is included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedule of the Company (page S-2) listed in the accompanying index at Item 15. This consolidated financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Alabama Power Company

We have audited the financial statements of Alabama Power Company (the "Company") as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and have issued our report thereon dated February 25, 2009; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (page S-3) listed in the accompanying index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Birmingham, Alabama
February 25, 2009

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Georgia Power Company

We have audited the financial statements of Georgia Power Company (the "Company") as of December 31, 2008 and 2007; and for each of the three years in the period ended December 31, 2008, and have issued our report thereon dated February 25, 2009; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (page S-4) listed in the accompanying index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Gulf Power Company

We have audited the financial statements of Gulf Power Company (the "Company") as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and have issued our report thereon dated February 25, 2009; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (page S-5) listed in the accompanying index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

Member of
Deloitte Touche Tohmatsu

Deloitte.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Mississippi Power Company

We have audited the financial statements of Mississippi Power Company (the "Company") as of December 31, 2008 and 2007, and for each of the three years in the period ended December 31, 2008, and have issued our report thereon dated February 25, 2009; such report is included elsewhere in this Form 10-K. Our audits also included the financial statement schedule of the Company (page S-6) listed in the accompanying index at Item 15. This financial statement schedule is the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

Deloitte & Touche LLP

Atlanta, Georgia
February 25, 2009

Member of
Deloitte Touche Tohmatsu

INDEX TO FINANCIAL STATEMENT SCHEDULES

Schedule II **Page**

Valuation and Qualifying Accounts and Reserves 2008, 2007, and 2006

The Southern Company and Subsidiary Companies S-2

Alabama Power Company S-3

Georgia Power Company S-4

Gulf Power Company S-5

Mississippi Power Company S-6

Schedules I through V not listed above are omitted as not applicable or not required. A Schedule II for Southern Power Company and Subsidiary Companies is not being provided because there were no reportable items for the three-year period ended December 31, 2008. Columns omitted from schedules filed have been omitted because the information is not applicable or not required.

THE SOUTHERN COMPANY AND SUBSIDIARY COMPANIES
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007, AND 2006
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions Charged to Income	Additions Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2008	$ 22,142	$60,184	$ -	$56,000 (a)	$ 26,326
2007	34,901	34,471	-	47,230 (a)	22,142
2006	37,510	49,226	1,230	53,065 (a)	34,901
Tax valuation allowance					
2008 (b)	$ -	$ -	$ -	$-	$ -
2007 (b)	-	-	-	-	-
2006	10,160	53,164	-	-	63,324

(a) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*
(b) *See Note 5 to the financial statements of Southern Company in Item 8 herein.*

ALABAMA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007, AND 2006
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2008	$ 7,988	$20,824	$-	$19,930 (Note)	$ 8,882
2007	7,091	16,678	-	15,781 (Note)	7,988
2006	7,560	14,130	-	14,599 (Note)	7,091

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

GEORGIA POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007, AND 2006
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2008	$ 7,636	$31,219	$-	$28,123 (a)	$10,732
2007	10,030	20,336	-	22,730 (a)	7,636
2006	9,563	26,503	-	26,036 (a)	10,030
Tax valuation allowance					
2008 (b)	$ -	$ -	$-	$-	$ -
2007 (b)	-	-	-	-	-
2006	10,160	53,164	-	-	63,324

(a) *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*
(b) *See Note 5 to the financial statements of Georgia Power in Item 8 herein.*

GULF POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007, AND 2006
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2008	$ 1,711	$3,893	$-	$3,416 (Note)	$2,188
2007	1,279	3,315	-	2,883 (Note)	1,711
2006	1,134	2,612	-	2,467 (Note)	1,279

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

MISSISSIPPI POWER COMPANY
SCHEDULE II — VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2008, 2007, AND 2006
(Stated in Thousands of Dollars)

Description	Balance at Beginning of Period	Additions: Charged to Income	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
Provision for uncollectible accounts					
2008	$ 924	$2,372	$-	$2,257 (Note)	$1,039
2007	855	1,896	-	1,827 (Note)	924
2006	2,321	1,071	-	2,537 (Note)	855

Note: *Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.*

EXHIBIT INDEX

The following exhibits indicated by an asterisk (*) preceding the exhibit number are filed herewith. The balance of the exhibits has heretofore been filed with the SEC as the exhibits and in the file numbers indicated and are incorporated herein by reference. The exhibits marked with a pound sign (#) are management contracts or compensatory plans or arrangements required to be identified as such by Item 15 of Form 10-K.

(3) Articles of Incorporation and By-Laws

Southern Company

(a) 1 - Composite Certificate of Incorporation of Southern Company, reflecting all amendments thereto through January 5, 1994. (Designated in Registration No. 33-3546 as Exhibit 4(a), in Certificate of Notification, File No. 70-7341, as Exhibit A, and in Certificate of Notification, File No. 70-8181, as Exhibit A.)

(a) 2 - By-laws of Southern Company as amended effective February 17, 2003, and as presently in effect. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2003, File No. 1-3526, as Exhibit 3(a)1.)

Alabama Power

(b) 1 - Charter of Alabama Power and amendments thereto through April 25, 2008. (Designated in Registration Nos. 2-59634 as Exhibit 2(b), 2-60209 as Exhibit 2(c), 2-60484 as Exhibit 2(b), 2-70838 as Exhibit 4(a)-2, 2-85987 as Exhibit 4(a)-2, 33-25539 as Exhibit 4(a)-2, 33-43917 as Exhibit 4(a)-2, in Form 8-K dated February 5, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated July 8, 1992, File No. 1-3164, as Exhibit 4(b)-3, in Form 8-K dated October 27, 1993, File No. 1-3164, as Exhibits 4(a) and 4(b), in Form 8-K dated November 16, 1993, File No. 1-3164, as Exhibit 4(a), in Certificate of Notification, File No. 70-8191, as Exhibit A, in Alabama Power's Form 10-K for the year ended December 31, 1997, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated August 10, 1998, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-K for the year ended December 31, 2000, File No. 1-3164, as Exhibit 3(b)2, in Alabama Power's Form 10-K for the year ended December 31, 2001, File No. 1-3164, as Exhibit 3(b)2, in Form 8-K dated February 5, 2003, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2003, File No 1-3164, as Exhibit 3(b)1, in Form 8-K dated February 5, 2004, File No. 1-3164, as Exhibit 4.4, in Alabama Power's Form 10-Q for the quarter ended March 31, 2006, File No. 1-3164, as Exhibit 3(b)(1), in Form 8-K dated December 5, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 12, 2007, File No. 1-3164, as Exhibit 4.5, in Form 8-K dated October 17, 2007, File No. 1-3164, as Exhibit 4.5, and in Alabama Power's Form 10-Q for the quarter ended March 31, 2008, File No. 1-3164, as Exhibit 3(b)1.)

(b) 2 - By-laws of Alabama Power as amended effective January 26, 2007, and as presently in effect. (Designated in Form 8-K dated January 26, 2007, File No 1-3164, as Exhibit 3(b)2.)

Georgia Power

(c) 1 - Charter of Georgia Power and amendments thereto through October 9, 2007. (Designated in Registration Nos. 2-63392 as Exhibit 2(a)-2, 2-78913 as Exhibits 4(a)-(2) and 4(a)-(3), 2-93039 as Exhibit 4(a)-(2), 2-96810 as Exhibit 4(a)-2, 33-141 as Exhibit 4(a)-(2), 33-1359 as Exhibit 4(a)(2), 33-5405 as Exhibit 4(b)(2), 33-14367 as Exhibits 4(b)-(2) and 4(b)-(3), 33-22504 as Exhibits 4(b)-(2), 4(b)-(3) and 4(b)-(4), in Georgia Power's Form 10-K for the year ended December 31, 1991, File No. 1-6468, as Exhibits 4(a)(2) and 4(a)(3), in

Registration No. 33-48895 as Exhibits 4(b)-(2) and 4(b)-(3), in Form 8-K dated December 10, 1992, File No. 1-6468 as Exhibit 4(b), in Form 8-K dated June 17, 1993, File No. 1-6468, as Exhibit 4(b), in Form 8-K dated October 20, 1993, File No. 1-6468, as Exhibit 4(b), in Georgia Power's Form 10-K for the year ended December 31, 1997, File No. 1-6468, as Exhibit 3(c)2, in Georgia Power's Form 10-K for the year ended December 31, 2000, File No. 1-6468, as Exhibit 3(c)2, in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 3.1, and in Form 8-K dated October 3, 2007, File No. 1-6468, as Exhibit 4.5.)

(c) 2 - By-laws of Georgia Power as amended effective August 17, 2005, and as presently in effect. (Designated in Form 8-K dated August 17, 2005, File No. 1-6468, as Exhibit 3(c)2.)

Gulf Power

(d) 1 - Amended and Restated Articles of Incorporation of Gulf Power and amendments thereto through October 17, 2007. (Designated in Form 8-K dated October 27, 2005, File No. 0-2429, as Exhibit 3.1, in Form 8-K dated November 9, 2005, File No. 0-2429, as Exhibit 4.7, and in Form 8-K dated October 16, 2007, File No. 0-2429, as Exhibit 4.5.)

(d) 2 - By-laws of Gulf Power as amended effective November 2, 2005, and as presently in effect. (Designated in Form 8-K dated November 2, 2005, File No. 0-2429, as Exhibit 3.2.)

Mississippi Power

(e) 1 - Articles of Incorporation of Mississippi Power, articles of merger of Mississippi Power Company (a Maine corporation) into Mississippi Power and articles of amendment to the articles of incorporation of Mississippi Power through April 2, 2004. (Designated in Registration No. 2-71540 as Exhibit 4(a)-1, in Form U5S for 1987, File No. 30-222-2, as Exhibit B-10, in Registration No. 33-49320 as Exhibit 4(b)-(1), in Form 8-K dated August 5, 1992, File No. 0-6849, as Exhibits 4(b)-2 and 4(b)-3, in Form 8-K dated August 4, 1993, File No. 0-6849, as Exhibit 4(b)-3, in Form 8-K dated August 18, 1993, File No. 0-6849, as Exhibit 4(b)-3, in Mississippi Power's Form 10-K for the year ended December 31, 1997, File No. 0-6849, as Exhibit 3(e)2, in Mississippi Power's Form 10-K for the year ended December 31, 2000, File No. 0-6849, as Exhibit 3(e)2, and in Form 8-K dated March 3, 2004, File No. 0-6849, as Exhibit 4.6.)

(e) 2 - By-laws of Mississippi Power as amended effective February 28, 2001, and as presently in effect. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2001, File No. 0-6849, as Exhibit 3(e)2.)

Southern Power

(f) 1 - Certificate of Incorporation of Southern Power dated January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.1.)

(f) 2 - By-laws of Southern Power effective January 8, 2001. (Designated in Registration No. 333-98553 as Exhibit 3.2.)

(4) Instruments Describing Rights of Security Holders, Including Indentures

Southern Company

(a) 1 - Senior Note Indenture dated as of February 1, 2002, among Southern Company, Southern Company Capital Funding, Inc. and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through November 16, 2005. (Designated in Form 8-K dated January 29, 2002, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated January 30, 2002, File No. 1-3526, as Exhibit 4.2 and in Form 8-K dated November 8, 2005, File No. 1-3526, as Exhibit 4.2.)

(a) 2 - Senior Note Indenture dated as of January 1, 2007, between Southern Company and Wells Fargo Bank, National Association, as Trustee, and indentures supplemental thereto through August 21, 2008. (Designated in Form 8-K dated January 11, 2006, File No. 1-3526, as Exhibits 4.1 and 4.2, in Form 8-K dated March 20, 2007, File No. 1-3526, as Exhibit 4.2, and in Form 8-K dated August 13, 2008, File No. 1-3526, as Exhibit 4.2.)

Alabama Power

(b) 1 - Subordinated Note Indenture dated as of January 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through October 2, 2002. (Designated in Form 8-K dated January 9, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 18, 1999, File No. 3164, as Exhibit 4.2 and in Form 8-K dated September 26, 2002, File No. 3164, as Exhibits 4.9-A and 4.9-B.)

(b) 2 - Senior Note Indenture dated as of December 1, 1997, between Alabama Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through November 14, 2008. (Designated in Form 8-K dated December 4, 1997, File No. 1-3164, as Exhibits 4.1 and 4.2, in Form 8-K dated February 20, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 17, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 11, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 8, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 16, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 7, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 28, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 12, 1998, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 19, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 13, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated September 21, 1999, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 11, 2000, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 22, 2001, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated June 21, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated October 16, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated November 20, 2002, File No. 1-3164, as Exhibit 4.2(a), in Form 8-K dated December 6, 2002, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 11, 2003, File No. 1-3164, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 12, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 15, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 1, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 14, 2003, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 10, 2004, File No. 1-3164, as Exhibit 4.2 in Form 8-K dated April 7, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated August 19, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated November 9, 2004, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated March 8, 2005, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 11, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 13, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated February 1, 2006, File No. 1-3164, as Exhibits

4.2(a) and 4.2(b), in Form 8-K dated March 9, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated June 7, 2006, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated January 30, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated April 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated October 11, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated December 4, 2007, File No. 1-3164, as Exhibit 4.2, in Form 8-K dated May 8, 2008, File No. 1-3164, as Exhibit 4.2, and in Form 8-K dated November 14, 2008, File No. 1-3164 as Exhibit 4.2.)

(b) 3 - Amended and Restated Trust Agreement of Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.12-B.)

(b) 4 - Guarantee Agreement relating to Alabama Power Capital Trust V dated as of September 1, 2002. (Designated in Form 8-K dated September 26, 2002, File No. 1-3164, as Exhibit 4.16-B.)

Georgia Power

(c) 1 - Subordinated Note Indenture dated as of June 1, 1997, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through January 23, 2004. (Designated in Certificate of Notification, File No. 70-8461, as Exhibits D and E, in Form 8-K dated February 17, 1999, File No. 1-6468, as Exhibit 4.4, in Form 8-K dated June 13, 2002, File No. 1-6468, as Exhibit 4.4, in Form 8-K dated October 30, 2002, File No. 1-6468, as Exhibit 4.4 and in Form 8-K dated January 15, 2004, File No. 1-6468, as Exhibit 4.4.)

(c) 2 - Senior Note Indenture dated as of January 1, 1998, between Georgia Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through February 10, 2009. (Designated in Form 8-K dated January 21, 1998, File No. 1-6468, as Exhibits 4.1 and 4.2, in Forms 8-K each dated November 19, 1998, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 3, 1999, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated February 15, 2000, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated January 26, 2001, File No. 1-6469 as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated February 16, 2001, File No. 1-6469 as Exhibit 4.2, in Form 8-K dated May 1, 2001, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 27, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 15, 2002, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 13, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated February 21, 2003, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated April 10, 2003, File No. 1-6468, as Exhibits 4.1, 4.2 and 4.3, in Form 8-K dated September 8, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated September 23, 2003, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated January 12, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated February 12, 2004, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated August 11, 2004, File No. 1-6468, as Exhibits 4.1 and 4.2, in Form 8-K dated January 13, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated April 12, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated November 30, 2005, File No. 1-6468, as Exhibit 4.1, in Form 8-K dated December 8, 2006, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 6, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 4, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 18, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated July 10, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated October 23, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 29, 2007, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated March 12, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated June 5, 2008, File No. 1-6468, as Exhibit 4.2, in Form 8-K dated November 12, 2008, File No. 1-6468, as Exhibits 4.2(a) and 4.2(b), and in Form 8-K dated February 4, 2009, File No. 1-6468, as Exhibit 4.2.)

(c) 3 - Senior Note Indenture dated as of March 1, 1998 between Georgia Power, as successor to Savannah Electric, and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through June 30, 2006. (Designated in Form 8-K dated March 9, 1998, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated May 8, 2001, File No. 1-5072, as Exhibits 4.2(a) and 4.2(b), in Form 8-K dated March 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated November 4, 2002, File No. 1-5072, as Exhibit 4.2, in Form 8-K dated December 10, 2003, File No. 1-5072, as Exhibits 4.1 and 4.2, in Form 8-K dated December 2, 2004, File No. 1-5072, as Exhibit 4.1 and in Form 8-K dated June 27, 2006, File No. 1-6468, as Exhibit 4.2.)

(c) 4 - Amended and Restated Trust Agreement of Georgia Power Capital Trust VII dated as of January 1, 2004. (Designated in Form 8-K dated January 15, 2004, as Exhibit 4.7-A.)

(c) 5 - Guarantee Agreement relating to Georgia Power Capital Trust VII dated as of January 1, 2004. (Designated in Form 8-K dated January 15, 2004, as Exhibit 4.11-A.)

Gulf Power

(d) 1 - Senior Note Indenture dated as of January 1, 1998, between Gulf Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through June 12, 2007. (Designated in Form 8-K dated June 17, 1998, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated August 17, 1999, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 31, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated October 5, 2001, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated January 18, 2002, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated March 21, 2003, File No. 0-2429, as Exhibit 4.2, in Form 8-K dated July 10, 2003, File No. 0-2429, as Exhibits 4.1 and 4.2, in Form 8-K dated September 5, 2003, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated April 6, 2004, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated September 13, 2004, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated August 11, 2005, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated October 27, 2005, File No. 0-2429, as Exhibit 4.1, in Form 8-K dated November 28, 2006, File No. 0-2429, as Exhibit 4.2, and in Form 8-K dated June 5, 2007, File No. 0-2429, as Exhibit 4.2.)

Mississippi Power

(e) 1 - Senior Note Indenture dated as of May 1, 1998 between Mississippi Power and Wells Fargo Bank, National Association, as Successor Trustee, and indentures supplemental thereto through November 21, 2008. (Designated in Form 8-K dated May 14, 1998, File No. 0-6849, as Exhibits 4.1, 4.2(a) and 4.2(b), in Form 8-K dated March 22, 2000, File No. 0-6849, as Exhibit 4.2, in Form 8-K dated March 12, 2002, File No. 0-6849, as Exhibit 4.2, in Form 8-K dated April 24, 2003, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated March 3, 2004, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated June 24, 2005, File No. 001-11229, as Exhibit 4.2, in Form 8-K dated November 8, 2007, File No. 001-11229, as Exhibit 4.2, and in Form 8-K dated November 14, 2008, File No. 001-11229, as Exhibit 4.2.)

Southern Power

(f) 1 - Senior Note Indenture dated as of June 1, 2002, between Southern Power and The Bank of New York Mellon (as successor to JPMorgan Chase Bank, N.A. (formerly known as The Chase Manhattan Bank)), as Trustee, and indentures supplemental thereto through November 21, 2006. (Designated in Registration No. 333-98553 as Exhibits 4.1 and 4.2 and in Southern Power's Form 10-Q for the quarter ended June 30, 2003, File No. 333-98553, as Exhibit 4(g)1, and in Form 8-K dated November 13, 2006, File No. 333-98553, as Exhibit 4.2.)

(10) Material Contracts

Southern Company

* (a) 1 - Amended and Restated Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2007.

(a) 2 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2006, File No. 1-3526, as Exhibit 10(a)2.)

(a) 3 - Deferred Compensation Plan for Directors of The Southern Company, Amended and Restated effective January 1, 2008. (Designated in Southern Company's Form 10-K for the year ended December 31, 2007, File No. 1-3536, as Exhibit 10(a)3.)

* (a) 4 - Southern Company Deferred Compensation Plan as amended and restated effective January 1, 2009.

(a) 5 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. (Designated in Southern Company's Form 10-Q for the quarter ended June 30, 2004, File No. 1-3526, as Exhibit 10(a)2.)

* (a) 6 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective as of January 1, 2009.

* (a) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009.

* (a) 8 - Amended and Restated Change in Control Agreement dated December 31, 2008 between Southern Company, SCS, and G. Edison Holland, Jr.

* (a) 9 - Amended and Restated Change in Control Agreement dated December 31, 2008 between Southern Company, Alabama Power, and Charles D. McCrary.

* (a) 10 - Amended and Restated Change in Control Agreement dated December 31, 2008 between Southern Company, SCS, and David M. Ratcliffe.

(a) 11 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.1.)

(a) 12 - Master Separation and Distribution Agreement dated as of September 1, 2000 between Southern Company and Mirant. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)100.)

(a) 13 - Indemnification and Insurance Matters Agreement dated as of September 1, 2000 between Southern Company and Mirant. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)101.)

(a) 14 - Tax Indemnification Agreement dated as of September 1, 2000 among Southern Company and its affiliated companies and Mirant and its affiliated companies. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)102.)

(a) 15 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)103.)

* (a) 16 - First Amendment effective January 1, 2009 to the Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear.

(a) 17 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2000, File No. 1-3526, as Exhibit 10(a)104.)

* (a) 18 - First Amendment effective January 1, 2009 to the Southern Company Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power.

(a) 19 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)92.)

* (a) 20 - First Amendment effective January 1, 2009 to the Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power.

* (a) 21 - Amended and Restated Change in Control Agreement effective December 31, 2008 between Southern Company, SCS, and Thomas A. Fanning.

(a) 22 - Amended Deferred Compensation Agreement among Southern Company, SCS, Georgia Power, Gulf Power, and G. Edison Holland, Jr. effective December 31, 2008. (Designated in Form 8-K dated December 31, 2008, File No. 1-3526, as Exhibit 10.2.)

* (a) 23 - Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008.

* (a) 24 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008.

* (a) 25 - Amended and Restated Change in Control Agreement effective December 31, 2008 between Southern Company, Georgia Power, and Michael D. Garrett.

* (a) 26 - Amended and Restated Change in Control Agreement effective December 31, 2008 between Southern Company, SCS, and William Paul Bowers.

(a) 27 - Form of Restricted Stock Award Agreement. (Designated in Form 10-Q for the quarter ended September 30, 2007, File No. 1-3526, as Exhibit 10(a)1.)

(a) 28 - Compensation and Retention Agreement between SCS and C. Alan Martin effective as of February 1, 2008. (Designated in Form 10-Q for the quarter ended September 30, 2008, File No. 1-3526, as Exhibit 10(a)1.)

* (a) 29 - Base Salaries of Named Executive Officers.

(a) 30 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-3526, as Exhibit 10(a)27.)

Alabama Power

(b) 1 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. (Designated in Form 10-Q for the quarter ended March 31, 2007, File No. 1-3164, as Exhibit 10(b)5.)

(b) 2 - Amended and Restated Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2007. See Exhibit 10(a)1 herein.

(b) 3 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. See Exhibit 10(a)2 herein.

(b) 4 - Southern Company Deferred Compensation Plan as amended and restated effective January 1, 2009. See Exhibit 10(a)4 herein.

(b) 5 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(b) 6 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective as of January 1, 2009. See Exhibit 10(a)6 herein.

(b) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009. See Exhibit 10(a)7 herein.

(b) 8 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008. See Exhibit 10(a)24 herein.

(b) 9 - Deferred Compensation Plan for Directors of Alabama Power Company, Amended and Restated effective January 1, 2008. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2008, File No. 1-3164, as Exhibit 10(b)1.)

(b) 10 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)11 herein.

(b) 11 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless,

Southern Company Energy Solutions, LLC, and Southern Nuclear. See Exhibit 10(a)15 herein.

(b) 12 - First Amendment effective January 1, 2009 to the Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear. See Exhibit 10(a)16 herein.

(b) 13 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)17 herein.

(b) 14 - First Amendment effective January 1, 2009 to the Southern Company Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)18 herein.

(b) 15 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)19 herein.

(b) 16 - First Amendment effective January 1, 2009 to the Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)20 herein.

(b) 17 - Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008. See Exhibit 10(a)23 herein.

(b) 18 - Amended and Restated Change in Control Agreement dated December 31, 2008 between Southern Company, Alabama Power, and Charles D. McCrary. See Exhibit 10(a)9 herein.

(b) 19 - Amended and Restated Change in Control Agreement between Southern Company, Alabama Power, and C. Alan Martin, effective June 1, 2004. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2004, File No. 1-3526, as Exhibit 10(b)4.)

* (b) 20 - Base Salaries of Named Executive Officers.

(b) 21 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Alabama Power's Form 10-K for the year ended December 31, 2004, File No. 1-3164, as Exhibit 10(b)20.)

(b) 22 - Form of Restricted Stock Award Agreement. See Exhibit 10(a)27 herein.

Georgia Power

(c) 1 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(c) 2 - Revised and Restated Integrated Transmission System Agreement dated as of November 12, 1990, between Georgia Power and OPC. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(g).)

(c) 3 - Revised and Restated Integrated Transmission System Agreement between Georgia Power and Dalton dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(gg).)

(c) 4 - Revised and Restated Integrated Transmission System Agreement between Georgia Power and MEAG dated as of December 7, 1990. (Designated in Georgia Power's Form 10-K for the year ended December 31, 1990, File No. 1-6468, as Exhibit 10(hh).)

(c) 5 - Amended and Restated Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2007. See Exhibit 10(a)1 herein.

(c) 6 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. See Exhibit 10(a)2 herein.

(c) 7 - Southern Company Deferred Compensation Plan as amended and restated effective January 1, 2009. See Exhibit 10(a)4 herein.

(c) 8 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(c) 9 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated as of January 1, 2009. See Exhibit 10(a)6 herein.

(c) 10 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009. See Exhibit 10(a)7 herein.

(c) 11 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008. See Exhibit 10(a)24 herein.

(c) 12 - Deferred Compensation Plan For Directors of Georgia Power Company, Amended and Restated Effective January 1, 2008. (Designated in Form 10-K for the year ended December 31, 2007, File No. 1-6468, as Exhibit 10(c)12.)

(c) 13 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)11 herein.

(c) 14 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001, between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear. See Exhibit 10(a)15 herein.

(c) 15 - First Amendment effective January 1, 2009 to the Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear. See Exhibit 10(a)16 herein.

(c) 16 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)17 herein.

(c) 17 - First Amendment effective January 1, 2009 to the Southern Company Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)18 herein.

(c) 18 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)19 herein.

(c) 19 - First Amendment effective January 1, 2009 to the Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)20 herein.

(c) 20 - Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008. See Exhibit 10(a)23 herein.

(c) 21 - Deferred Compensation Agreement between Southern Company, SCS, and Christopher C. Womack dated May 31, 2002. (Designated in Southern Company's Form 10-K for the year ended December 31, 2002, File No. 1-3526, as Exhibit 10(a)118.)

(c) 22 - Amended and Restated Supplemental Pension Agreement among SCS, Southern Nuclear, Alabama Power, and James H. Miller, III. (Designated in Alabama Power's Form 10-Q for the quarter ended June 30, 2003, File No. 1-3164, as Exhibit 10(b)1.)

(c) 23 - Amended and Restated Change in Control Agreement effective December 31, 2008 between Southern Company, Georgia Power, and Michael D. Garrett. See Exhibit 10(a)25 herein.

(c) 24 - Amended Deferred Compensation Agreement among Southern Company, SCS, Georgia Power, Gulf Power, and G. Edison Holland, Jr. effective December 31, 2008. See Exhibit 10(a)22 herein.

* (c) 25 - Base Salaries of Named Executive Officers.

(c) 26 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Georgia Power's Form 10-K for the year ended December 31, 2004, File No. 1-6468, as Exhibit 10(c)24.)

(c) 27 - Form of Restricted Stock Award Agreement. See Exhibit 10(a)27 herein.

(c) 28 - Engineering, Procurement and Construction Agreement, dated as of April 8, 2008, between Georgia Power, for itself and as agent for OPC, MEAG Power, and Dalton Utilities, as owners, and a consortium consisting of Westinghouse Electric Company LLC and Stone & Webster, Inc., as contractor, for Units 3 & 4 at the Vogtle Electric Generating Plant Site. (Georgia Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Georgia Power omitted such portions from the filing and filed them separately with the SEC.) (Designated in Form 10-Q/A for the quarter ended June 30, 2008, File No. 1-6468, as Exhibit 10(c)1.)

Gulf Power

(d) 1 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(d) 2 - Unit Power Sales Agreement dated July 19, 1988, between FPC and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(d).)

(d) 3 - Amended Unit Power Sales Agreement dated July 20, 1988, between FP&L and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(e).)

(d) 4 - Amended Unit Power Sales Agreement dated August 17, 1988, between Jacksonville Electric Authority and Alabama Power, Georgia Power, Gulf Power, Mississippi Power, and SCS. (Designated in Savannah Electric's Form 10-K for the year ended December 31, 1988, File No. 1-5072, as Exhibit 10(f).)

(d) 5 - Amended and Restated Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2007. See Exhibit 10(a)1 herein.

(d) 6 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. See Exhibit 10(a)2 herein.

(d) 7 - Southern Company Deferred Compensation Plan as amended and restated effective January 1, 2009. See Exhibit 10(a)4 herein.

(d) 8 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(d) 9 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009. See Exhibit 10(a)7 herein.

(d) 10 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008. See Exhibit 10(a)24 herein.

(d) 11 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective as of January 1, 2009. See Exhibit 10(a)6 herein.

(d) 12 - Deferred Compensation Plan For Outside Directors of Gulf Power Company, Amended and Restated effective January 1, 2008. (Designated in Gulf Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-2429, as Exhibit 10(d)1.)

(d) 13 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)11 herein.

(d) 14 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear. See Exhibit 10(a)15 herein.

(d) 15 - First Amendment effective January 1, 2009 to the Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear. See Exhibit 10(a)16 herein.

(d) 16 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)17 herein.

(d) 17 - First Amendment effective January 1, 2009 to the Southern Company Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)18 herein.

(d) 18 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)19 herein.

(d) 19 - First Amendment effective January 1, 2009 to the Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)20 herein.

(d) 20 - Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008. See Exhibit 10(a)23 herein.

* (d) 21 - Base Salaries of Named Executive Officers.

(d) 22 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Gulf Power's Form 10-K for the year ended December 31, 2004, File No. 0-2429, as Exhibit 10(d)20.)

(d) 23 - Form of Restricted Stock Award Agreement. See Exhibit 10(a)27 herein.

Mississippi Power

(e) 1 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(e) 2 - Transmission Facilities Agreement dated February 25, 1982, Amendment No. 1 dated May 12, 1982 and Amendment No. 2 dated December 6, 1983, between Entergy Corporation (formerly Gulf States) and Mississippi Power. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 1981, File No. 0-6849, as Exhibit 10(f), in Mississippi Power's Form 10-K for the year ended December 31, 1982, File No. 0-6849, as Exhibit 10(f)(2), and in Mississippi Power's Form 10-K for the year ended December 31, 1983, File No. 0-6849, as Exhibit 10(f)(3).)

(e) 3 - Amended and Restated Southern Company 2006 Omnibus Incentive Compensation Plan, effective January 1, 2007. See Exhibit 10(a)1 herein.

(e) 4 - Forms of Award Agreement under the Southern Company 2006 Omnibus Incentive Compensation Plan effective January 1, 2006. See Exhibit 10(a)2 herein.

(e) 5 - Southern Company Deferred Compensation Plan as amended and restated effective January 1, 2009. See Exhibit 10(a)4 herein.

(e) 6 - Outside Directors Stock Plan for The Southern Company and its Subsidiaries, effective May 26, 2004. See Exhibit 10(a)5 herein.

(e) 7 - The Southern Company Supplemental Benefit Plan, Amended and Restated effective as of January 1, 2009. See Exhibit 10(a)7 herein.

(e) 8 - Southern Company Executive Change in Control Severance Plan, Amended and Restated effective December 31, 2008. See Exhibit 10(a)24 herein.

(e) 9 - The Southern Company Supplemental Executive Retirement Plan, Amended and Restated effective as of January 1, 2009. See Exhibit 10(a)6 herein.

(e) 10 - Deferred Compensation Plan for Outside Directors of Mississippi Power Company, Amended and Restated effective January 1, 2008. (Designated in Mississippi Power's Form 10-Q for the quarter ended March 31, 2008, File No. 0-6849 as Exhibit 10(e)1.)

(e) 11 - The Southern Company Change in Control Benefits Protection Plan, effective December 31, 2008. See Exhibit 10(a)11 herein.

(e) 12 - Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear. See Exhibit 10(a)15 herein.

(e) 13 - First Amendment effective January 1, 2009 to the Southern Company Deferred Compensation Trust Agreement as amended and restated effective January 1, 2001 between Wachovia Bank, N.A., Southern Company, SCS, Alabama Power, Georgia Power, Gulf Power, Mississippi Power, SouthernLINC Wireless, Southern Company Energy Solutions, LLC, and Southern Nuclear. See Exhibit 10(a)16 herein.

(e) 14 - Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)17 herein.

(e) 15 - First Amendment effective January 1, 2009 to the Southern Company Deferred Stock Trust Agreement for Directors of Southern Company and its subsidiaries, dated as of January 1, 2000, between Reliance Trust Company, Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)18 herein.

(e) 16 - Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)19 herein.

(e) 17 - First Amendment effective January 1, 2009 to the Amended and Restated Deferred Cash Compensation Trust Agreement for Directors of Southern Company and its subsidiaries, effective September 1, 2001, between Wachovia Bank, N.A., Southern Company, Alabama Power, Georgia Power, Gulf Power, and Mississippi Power. See Exhibit 10(a)20 herein.

(e) 18 - Amended and Restated Southern Company Senior Executive Change in Control Severance Plan effective December 31, 2008. See Exhibit 10(a)23 herein.

* (e) 19 - Base Salaries of Named Executive Officers.

(e) 20 - Summary of Non-Employee Director Compensation Arrangements. (Designated in Mississippi Power's Form 10-K for the year ended December 31, 2004, File No. 001-11229, as Exhibit 10(e)20.)

(e) 21 - Form of Restricted Stock Award Agreement. See Exhibit 10(a)27 herein.

* (e) 22 - Cooperative Agreement between the DOE and SCS dated as of December 12, 2008. (Mississippi Power has requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Mississippi Power has omitted such portions from this filing and filed them separately with the SEC.)

Southern Power

(f) 1 - Service contract dated as of January 1, 2001, between SCS and Southern Power. (Designated in Southern Company's Form 10-K for the year ended December 31, 2001, File No. 1-3526, as Exhibit 10(a)(2).)

(f) 2 - Intercompany Interchange Contract as revised effective May 1, 2007, among Alabama Power, Georgia Power, Gulf Power, Mississippi Power, Southern Power, and SCS. See Exhibit 10(b)1 herein.

(f) 3 - Power Purchase Agreement between Southern Power and Alabama Power dated as of June 1, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.18.)

(f) 4 - Amended and Restated Power Purchase Agreement between Southern Power and Georgia Power at Plant Autaugaville dated as of August 6, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.19.)

(f) 5 - Contract for the Purchase of Firm Capacity and Energy between Southern Power and Georgia Power dated as of July 26, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.21.)

(f) 6 - Power Purchase Agreement between Southern Power and Georgia Power at Plant Goat Rock dated as of March 30, 2001. (Designated in Registration No. 333-98553 as Exhibit 10.22.)

(f) 7 - Purchase and Sale Agreement, by and between CP Oleander, LP and CP Oleander I, Inc., as Sellers, Constellation Power, Inc. and SP Newco I LLC and SP Newco II LLC, as Purchasers, and Southern Power, as Purchaser's Parent, for the Sale of Partnership Interests of Oleander Power Project, LP, dated as of April 8, 2005. (Designated in Form 8-K dated June 7, 2005, File No. 333-98553, as Exhibit 2.1)

(f) 8 - Multi-Year Credit Agreement dated as of July 7, 2006 by and among Southern Power, the Lenders (as defined therein), Citibank, N.A., as Administrative Agent, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as Initial Issuing Bank and Amendment Number One thereto. (Designated in Southern Power's Form 10-Q for the quarter ended June 30, 2006, File No. 333-98553, as Exhibit 10(f)1 and in Form 10-Q for the quarter ended June 30, 2007, File No. 333-98553, as Exhibit 10(f)2.) (Omits schedules and exhibits. Southern Power agreed to provide supplementally the omitted schedules and exhibits to the SEC upon request.)

(f) 9 - Purchase and Sale Agreement by and between Progress Genco Ventures, LLC and Southern Power Company – DeSoto LLC dated May 8, 2006. (Designated in Form 8-K dated May 31, 2006, File No. 333-98553, as Exhibit 2.1.) (Omits schedules and exhibits. Southern Power agreed to provide supplementally the omitted schedules and exhibits to the SEC upon request.) (Southern Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Southern Power omitted such portions from the filing and filed them separately with the SEC.)

(f) 10 - Assignment and Assumption Agreement between Southern Power Company – Desoto LLC and Southern Power effective May 24, 2006. (Designated in Form 8-K dated May 31, 2006, File No. 333-98553, as Exhibit 2.2.)

(f) 11 - Purchase and Sale Agreement by and between Progress Genco Ventures, LLC and Southern Power Company – Rowan LLC dated May 8, 2006. (Designated in Southern Power's Form 10-Q for the quarter ended June 30, 2006, File No. 333-98553, as Exhibit 10(f)4.) (Omits schedules and exhibits. Southern Power agrees to provide supplementally the omitted schedules and exhibits to the SEC upon request.) (Southern Power requested confidential treatment for certain portions of this document pursuant to an application for confidential treatment sent to the SEC. Southern Power omitted such portions from the filing and filed them separately with the SEC.)

(f) 12 - Assignment and Assumption Agreement between Southern Power Company – Rowan LLC and Southern Power effective May 24, 2006. (Designated in Southern Power's Form 10-Q for the quarter ended June 30, 2006, File No. 333-98553, as Exhibit 10(f)5.)

(14) Code of Ethics

Southern Company

* (a) - The Southern Company Code of Ethics.

Alabama Power

(b) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Georgia Power

(c) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Gulf Power

(d) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Mississippi Power

(e) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

Southern Power

(f) - The Southern Company Code of Ethics. See Exhibit 14(a) herein.

(21) Subsidiaries of Registrants

Southern Company

* (a) - Subsidiaries of Registrant.

Alabama Power

(b) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Georgia Power

(c) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Gulf Power

(d) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Mississippi Power

(e) - Subsidiaries of Registrant. See Exhibit 21(a) herein.

Southern Power

Omitted pursuant to General Instruction I(2)(b) of Form 10-K.

(23) Consents of Experts and Counsel

Southern Company

* (a) 1 - Consent of Deloitte & Touche LLP.

Alabama Power

* (b) 1 - Consent of Deloitte & Touche LLP.

Georgia Power

* (c) 1 - Consent of Deloitte & Touche LLP.

Gulf Power

* (d) 1 - Consent of Deloitte & Touche LLP.

Mississippi Power

* (e) 1 - Consent of Deloitte & Touche LLP.

Southern Power

* (f) 1 - Consent of Deloitte & Touche LLP.

(24) Powers of Attorney and Resolutions

Southern Company

* (a) - Power of Attorney and resolution.

Alabama Power

* (b) - Power of Attorney and resolution.

Georgia Power

* (c) - Power of Attorney and resolution.

Gulf Power

* (d) - Power of Attorney and resolution.

Mississippi Power

* (e) - Power of Attorney and resolution.

Southern Power

* (f) - Power of Attorney and resolution.

(31) Section 302 Certifications

Southern Company

* (a) 1 - Certificate of Southern Company's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (a) 2 - Certificate of Southern Company's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b) 1 - Certificate of Alabama Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (b) 2 - Certificate of Alabama Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Georgia Power

* (c) 1 - Certificate of Georgia Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (c) 2 - Certificate of Georgia Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Gulf Power

* (d) 1 - Certificate of Gulf Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (d) 2 - Certificate of Gulf Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

* (e) 1 - Certificate of Mississippi Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (e) 2 - Certificate of Mississippi Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

Southern Power

* (f) 1 - Certificate of Southern Power's Chief Executive Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

* (f) 2 - Certificate of Southern Power's Chief Financial Officer required by Section 302 of the Sarbanes-Oxley Act of 2002.

(32) Section 906 Certifications

Southern Company

* (a) - Certificate of Southern Company's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Alabama Power

* (b) - Certificate of Alabama Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Georgia Power

* (c) - Certificate of Georgia Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Gulf Power

* (d) - Certificate of Gulf Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Mississippi Power

* (e) - Certificate of Mississippi Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

Southern Power

* (f) - Certificate of Southern Power's Chief Executive Officer and Chief Financial Officer required by Section 906 of the Sarbanes-Oxley Act of 2002.

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