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

# Form 10-K

**(Mark One)**

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the fiscal year ended December 31, 2005**

**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 1-2745**

# Southern Natural Gas Company
(Exact Name of Registrant as Specified in Its Charter)

| | |
|---|---|
| **Delaware**<br>(State or Other Jurisdiction of Incorporation or Organization) | **63-0196650**<br>(I.R.S. Employer Identification No.) |
| **El Paso Building**<br>**1001 Louisiana Street**<br>**Houston, Texas**<br>(Address of Principal Executive Offices) | **77002**<br>(Zip Code) |

**Telephone Number: (713) 420-2600**

**Securities registered pursuant to Section 12(b) of the Act: None**

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

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 ☐

Indicate by check mark whether the registrant (1) has 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 registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ 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 registrant's 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. ☑

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

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☑

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☑

**State the aggregate market value of the voting stock held by non-affiliates of the registrant: None**

**Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date.**

Common Stock, par value $1 per share. Shares outstanding on March 15, 2006: 1,000

**SOUTHERN NATURAL GAS COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTION I(1)(a) AND (b) TO FORM 10-K AND IS THEREFORE FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY SUCH INSTRUCTION.**

**Documents Incorporated by Reference: None**

**SOUTHERN NATURAL GAS COMPANY**

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* We have not included a response to this item in this document since no response is required pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Below is a list of terms that are common to our industry and used throughout this document:

| | | | |
|---|---|---|---|
| /d | = per day | LNG | = liquefied natural gas |
| BBtu | = billion British thermal units | MMcf | = million cubic feet |
| Bcf | = billion cubic feet | | |

When we refer to cubic feet measurements, all measurements are at a pressure of 14.73 pounds per square inch.

When we refer to “us”, “we”, “our”, “ours”, or “SNG”, we are describing Southern Natural Gas Company and/or our subsidiaries.

# PART I

## ITEM 1. BUSINESS

*Overview and Strategy*

We are a Delaware corporation incorporated in 1935, and a wholly owned subsidiary of El Paso Corporation (El Paso). Our primary business consists of the interstate transportation and storage of natural gas and LNG terminalling operations. We conduct our business activities through natural gas pipeline systems, which include our Southern Natural Gas (SNG) pipeline system and our 50 percent indirect ownership interest in the Florida Gas Transmission (FGT) pipeline system, a LNG receiving terminal and storage facilities as discussed below.

Each of our pipeline systems and storage facilities operate under tariffs approved by the Federal Energy Regulatory Commission (FERC) that establish rates, cost recovery mechanisms, terms and conditions of service to our customers. The fees or rates established under our tariffs are a function of our costs of providing services to our customers, including a reasonable return on our invested capital. Our revenues from transportation, storage, LNG terminalling and related services consist of two types of revenues:

*Reservation revenues.* Reservation revenues are from customers (referred to as firm customers) that reserve capacity on our pipeline system, storage facilities or LNG terminalling facilities. These firm customers are obligated to pay a monthly reservation or demand charge, regardless of the amount of natural gas they transport or store, for the term of their contracts.

*Usage revenues.* Usage revenues are from both firm customers and interruptible customers (those without reserved capacity) who pay usage charges based on the volume of gas actually transported, stored, injected or withdrawn.

In 2005, approximately 89 percent of our revenues were attributable to reservation charges paid by firm customers. The remaining 11 percent of our revenues were variable. Because of our regulated nature and the high percentage of our revenues attributable to reservation charges, our revenues have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices and market conditions, regulatory actions, competition, the creditworthiness of our customers and weather.

Our strategy is to protect and enhance the value of our transmission business through:

- Seeking to expand our systems by attracting new customers, markets or supply sources while leveraging our existing assets to the extent possible;
- Investing in maintenance and pipeline integrity projects to maintain the value and ensure the safety of our pipeline systems and assets; and
- Recontracting or contracting available or expiring capacity.

Below is a further discussion of our pipeline systems, storage facilities and LNG terminal.

*The SNG System.* The SNG pipeline system consists of approximately 7,700 miles of pipeline with a design capacity of approximately 3,450 MMcf/d. During 2005, 2004 and 2003, average throughput was 1,984 BBtu/d, 2,163 BBtu/d and 2,101 BBtu/d. This system extends from natural gas fields in Texas, Louisiana, Mississippi, Alabama and the Gulf of Mexico to markets in Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee, including the metropolitan areas of Atlanta and Birmingham. We are the principal natural gas transporter to growing southeastern markets in Alabama, Georgia and South Carolina.

Since 2001, the FERC has approved, and we placed in service, our South System I, South System II and North System II expansions, which were completely phased in service in August 2004. These expansions make up approximately 700 MMcf/d of our total design capacity. In addition, in November 2005, the FERC issued a preliminary determination that approved our Cypress expansion project to construct an additional

176 miles to our mainline system, which will increase our capacity by 500 MMcf/d. The expansion is estimated to cost approximately $321 million and will be phased in service over a four year period beginning in May 2007. Construction is expected to begin in May 2006 following the issuance of final certificate authorization by the FERC.

*The FGT System.* We have a 50 percent ownership interest in Citrus Corp. (Citrus), a Delaware corporation. Citrus owns 100 percent of the FGT pipeline system, which consists of approximately 4,867 miles of pipeline with a design capacity of 2,090 MMcf/d. During 2005, 2004 and 2003, average throughput was 1,916 BBtu/d, 2,014 BBtu/d and 1,963 BBtu/d. This system extends from south Texas to south Florida. For more information regarding our investment in Citrus and the FGT system, see Part II, Item 8, Financial Statement and Supplementary Data, Note 11 as well as Citrus' audited financial statements and related notes beginning on page 40 of this Form 10-K.

*LNG Terminal.* Our wholly owned subsidiary, Southern LNG Inc. (SLNG), owns an LNG receiving terminal located on Elba Island, near Savannah, Georgia. We recently completed an expansion of the Elba Island facility, which increased the peak sendout capacity to 1,215 MMcf/d and the base load sendout capacity to 806 MMcf/d. The capacity at the terminal is contracted with subsidiaries of British Gas and Royal Dutch Shell PLC.

*Storage Facilities.* Along our SNG pipeline system, we have a total of approximately 60 Bcf of underground working natural gas storage capacity. Our storage facilities include the Muldon storage facility in Monroe County, Mississippi, which has a storage capacity of 31 Bcf, and our 50 percent interest in Bear Creek Storage Company (Bear Creek), with our proportionate share of storage capacity of 29 Bcf.

Bear Creek is a joint venture that we own equally with our affiliate, Tennessee Storage Company (TSC), a subsidiary of Tennessee Gas Pipeline Company (TGP). Bear Creek owns and operates an underground natural gas storage facility located in Louisiana. The facility has a capacity of 50 Bcf of base gas and 58 Bcf of working storage. Bear Creek's working storage capacity is committed equally to TGP and us under long-term contracts.

*Markets and Competition*

Our customers consist of natural gas distribution and industrial companies, electric generation companies, natural gas producers, other natural gas pipelines, and natural gas marketing and trading companies. We provide transportation and storage services in both our natural gas supply and market areas. Our pipeline system connects with multiple pipelines that provide our customers with access to diverse sources of supply and various natural gas markets.

Imported LNG is one of the fastest growing supply sectors of the natural gas market. Terminals and other regasification facilities can serve as important sources of supply for pipelines, enhancing their delivery capabilities and operational flexibility and complementing traditional supply transported into market areas. However, these LNG delivery systems also may compete with us for transportation of gas into market areas we serve.

Electric power generation is the fastest growing demand sector of the natural gas market. The growth of the electric power industry potentially benefits the natural gas industry by creating more demand for natural gas turbine generated electric power. This effect is offset, in varying degrees, by increased generation efficiency, the more effective use of surplus electric capacity and increased natural gas prices. In addition, in several regions of the country, new additions in electric generating capacity have exceeded load growth and electric transmission capabilities out of those regions. These developments may inhibit owners of new power generation facilities from signing firm contracts with us.

Our existing transportation and storage contracts mature at various times and in varying amounts of throughput capacity. Our ability to extend our existing contracts or remarket expiring capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory requirements, we attempt to recontract or remarket our capacity at the rates allowed under our tariffs, although at times, we discount these rates to remain competitive.

The following table details the markets we serve and the competition on our SNG pipeline system as of December 31, 2005:

| Customer Information | Contract Information | Competition |
|---|---|---|
| Approximately 225 firm and interruptible customers | Approximately 181 firm transportation contracts.(1) Weighted average remaining contract term of approximately six years. | We face strong competition in a number of our key markets. We compete with other interstate and intrastate pipelines for deliveries to multiple-connection customers who can take deliveries at alternative points. Natural gas delivered on our system competes with alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil. Our four largest customers are able to obtain a significant portion of their natural gas requirements through transportation from other pipelines. Also, we compete with several pipelines for the transportation business of their customers. In addition, we compete with pipelines and gathering systems for connection to new supply sources. |
| Major Customers: | | |
| Atlanta Gas Light Company(2) (959 BBtu/d) | Contract terms expire in 2008-2015. | |
| Southern Company Services (418 BBtu/d) | Contract terms expire in 2010-2018. | |
| Alabama Gas Corporation (415 BBtu/d) | Contract terms expire in 2006-2013. | |
| Scana Corporation (346 BBtu/d) | Contract terms expire in 2006-2019. | |

(1) As a result of our 2005 rate case settlement discussed below, some of our firm transportation contracts were consolidated.

(2) Atlanta Gas Light Company is currently releasing a significant portion of its firm capacity to a subsidiary of Scana Corporation and to an affiliate of Southern Company Services under terms allowed by our tariff.

*Regulatory Environment*

Our interstate natural gas transmission system, storage and LNG terminalling operations are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. We operate under tariffs approved by the FERC that establish rates, terms and conditions of service to our customers. Generally, the FERC's authority extends to:

- rates and charges for natural gas transportation, storage and LNG terminalling;
- certification and construction of new facilities;
- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipeline and energy affiliates;
- terms and conditions of services;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

In March 2005, we placed revised rates into effect pursuant to a rate case settlement. Under the terms of the settlement, we increased our base tariff rates, reduced our fuel retention percentages, implemented an incentive sharing mechanism for gas not used in operations, received approval for a capital maintenance tracker, adjusted the rates for our South Georgia facilities, and agreed to file our next general rate case no earlier than March 1, 2009 and no later than March 31, 2010.

Our interstate pipeline systems and LNG terminal are also subject to federal, state and local statutes and regulations regarding pipeline and LNG safety and environmental matters. Our systems have ongoing inspection programs designed to keep all of our facilities in compliance with pipeline safety and environmental requirements and we believe that our systems are in material compliance with the applicable requirements.

We are subject to regulations over the safety requirements in the design, construction, operation and maintenance of our interstate natural gas transmission system and storage facilities by the U.S. Department of Transportation. Our LNG terminalling business is also regulated by the U.S. Coast Guard.

*Environmental*

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 7, and is incorporated herein by reference.

*Employees*

As of March 15, 2006, we had approximately 480 full-time employees, none of whom are subject to a collective bargaining arrangement.

## ITEM 1A. RISK FACTORS

### CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate," and similar expressions will generally identify forward-looking statements. Our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany those statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

With this in mind, you should consider the risks discussed elsewhere in this report and other documents we file with the Securities and Exchange Commission (SEC) from time to time and the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by us or on our behalf.

### Risks Related to Our Business

***Our success depends on factors beyond our control.***

Our business is the transportation and storage of natural gas and LNG terminalling operations for third parties. As a result, the volume of natural gas involved in these activities depends on the actions of those third parties and is beyond our control. Further, the following factors, most of which are beyond our control, may unfavorably impact our ability to maintain or increase current throughput, to renegotiate existing contracts as they expire or to remarket unsubscribed capacity:

- service area competition;
- expiration or turn back of significant contracts;
- changes in regulation and actions of regulatory bodies;
- future weather conditions;
- price competition;

- drilling activity and availability of natural gas;
- decreased availability of conventional gas supply sources and the availability and timing of other gas supply sources, such as LNG;
- decreased natural gas demand due to various factors, including increases in prices and the increased availability or popularity of alternative energy sources such as hydroelectric power, coal and fuel oil;
- increased costs of capital;
- opposition to energy infrastructure development, especially in environmentally sensitive areas;
- adverse general economic conditions; and
- unfavorable movements in natural gas and prices in supply and demand areas.

***The revenues of our pipeline businesses are generated under contracts that must be renegotiated periodically.***

Our revenues are generated under transportation and storage contracts that expire periodically and must be renegotiated and extended or replaced. Although we actively pursue the renegotiation, extension or replacement of these contracts, we cannot assure that we will be able to extend or replace these contracts when they expire or that the terms of any renegotiated contracts will be as favorable as the existing contracts. Currently, most of our firm transportation capacity is subscribed through mid-2010. For a further discussion of these matters, see Item 1, Business — Markets and Competition.

In particular, our ability to extend or replace transportation and storage contracts could be adversely affected by factors we cannot control, including:

- competition by other pipelines, including the proposed construction by other companies of additional pipeline capacity or LNG terminals in markets served by us;
- changes in state regulation of local distribution companies, which may cause them to negotiate short-term contracts or turn back their capacity when their contracts expire;
- reduced demand and market conditions in the areas we serve;
- the availability of alternative energy sources or gas supply points; and
- regulatory actions.

If we are unable to renew, extend or replace these contracts or if we renew them on less favorable terms, we may suffer a material reduction in our revenues and earnings.

***Fluctuations in energy commodity prices could adversely affect our business.***

Revenues generated by our transportation, storage and LNG terminalling contracts depend on volumes and rates, both of which can be affected by the prices of natural gas. Increased natural gas prices could result in a reduction of the volumes transported by our customers, such as power companies who, depending on the price of fuel, may not dispatch gas-fired power plants. Increased prices could also result in industrial plant shutdowns or load losses to competitive fuels as well as local distribution companies' loss of customer base. The success of our transmission, storage and LNG operations is subject to continued development of additional natural gas reserves and our ability to access additional supplies from interconnecting pipelines or LNG supplies, primarily in the Gulf of Mexico, to offset the natural decline from existing wells connected to our system. A decline in energy prices could cause a decrease in these development activities and could cause a decrease in the volume of natural gas available for transmission and storage through our system. Pricing volatility may, in some cases, impact the value of under or over recoveries of retained gas, as well as imbalances and system encroachments. If natural gas prices in the supply basins connected to our pipeline system are higher than prices in other natural gas producing regions, our ability to compete with other transporters may be negatively impacted. Furthermore, fluctuations in pricing between supply sources and market areas could negatively impact our transportation revenues. Fluctuations in energy prices are caused by a number of factors, including:

- regional, domestic and international supply and demand;
- availability and adequacy of transportation facilities;
- energy legislation;
- federal and state taxes, if any, on the transportation and storage of natural gas;
- abundance of supplies of alternative energy sources; and
- political unrest among oil producing countries.

***The agencies that regulate us and our customers affect our profitability.***

Our pipeline business is regulated by the FERC, the U.S. Department of Transportation and various state and local regulatory agencies. Our LNG terminalling business is also regulated by the U.S. Coast Guard. Regulatory actions taken by these agencies have the potential to adversely affect our profitability. In particular, the FERC regulates the rates we are permitted to charge our customers for our services. In setting authorized rates of return in recent FERC decisions, the FERC has utilized a proxy group of companies that includes local distribution companies that are not faced with as much competition or risks as interstate pipelines. The inclusion of these companies may create downward pressure on tariff rates that are submitted for approval. If our tariff rates were reduced or redesigned in a future rate proceeding, if our volume of business under our currently permitted rates were decreased significantly or if we were required to substantially discount the rates for our services because of competition, our profitability and liquidity could be reduced.

In addition, increased regulatory requirements relating to the integrity of our pipeline requires additional spending in order to maintain compliance with these requirements. Any additional requirements that are enacted could significantly increase the amount of these expenditures.

Further, state agencies that regulate our local distribution company customers could impose requirements that could impact demand for our services.

***Environmental compliance and remediation costs and the costs of environmental liabilities could exceed our estimates.***

Our operations are subject to various environmental laws and regulations regarding compliance and remediation obligations. Compliance obligations can result in significant costs to install and maintain pollution controls, fines and penalties resulting from any failure to comply and potential limitations on our operations. Remediation obligations can result in significant costs associated with the investigation and remediation or clean-up of contaminated properties (some of which have been designated as Superfund sites by the Environmental Protection Agency (EPA) under the Comprehensive Environmental Response, Compensation and Liability Act), as well as damage claims arising out of the contamination of properties or impact on natural resources. It is not possible for us to estimate exactly the amount and timing of all future expenditures related to environmental matters because of:

- The uncertainties in estimating pollution control and clean up costs, including sites where preliminary site investigation or assessments have been completed;
- The discovery of new sites or additional information at existing sites;
- The uncertainty in quantifying liability under environmental laws that impose joint and several liability on all potentially responsible parties; and
- The nature of environmental laws and regulations, including the interpretation and enforcement thereof.

Currently, various legislative and regulatory measures to address greenhouse gas (GHG) emissions (including carbon dioxide and methane) are in various phases of discussion or implementation. These include the Kyoto Protocol, proposed federal legislation and state actions to develop statewide or regional programs, each of which have imposed or would impose reductions in GHG emissions. These actions could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. These actions could also impact the consumption of natural gas, thereby affecting our operations.

Although we believe we have established appropriate reserves for our environmental liabilities, we could be required to set aside additional amounts due to these uncertainties which could significantly impact our future consolidated results of operations, cash flows or financial position. For additional information concerning our environmental matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 7.

***Our operations are subject to operational hazards and uninsured risks.***

Our operations are subject to the inherent risks normally associated with pipeline operations, including pipeline ruptures, explosions, pollution, release of toxic substances, fires, adverse weather conditions and other hazards, each of which could result in damage to or destruction of our facilities or damages or injuries to persons. In addition, our operations and assets face possible risks associated with acts of aggression. If any of these events were to occur, we could suffer substantial losses.

While we maintain insurance against many of these risks, to the extent and in amounts we believe are reasonable, this insurance does not cover all risks. Many of our insurance coverages have material deductibles and self-insurance levels, as well as limits on our maximum recovery. As a result, our financial condition and operations could be adversely affected if a significant event occurs that is not fully covered by insurance.

***Four customers contract for a majority of our firm transportation capacity.***

For 2005, our contracts with Atlanta Gas Light Company, Southern Company Services, Alabama Gas Corporation and Scana Corporation represented approximately 27 percent, 12 percent, 12 percent and 10 percent of our firm transportation capacity. For additional information, see Item 1, Business — Markets and Competition and Part II, Item 8, Financial Statements and Supplementary Data, Note 9. The loss of one of these customers or a decline in their creditworthiness could adversely affect our results of operations, financial position and cash flows.

***The expansion of our business by constructing new facilities subjects us to construction and other risks that may adversely affect our financial results.***

We may expand the capacity of our existing pipeline, storage and LNG terminalling facilities by constructing additional facilities. Construction of these facilities is subject to various regulatory, development and operational risks, including:

- our ability to obtain all necessary approvals and permits by regulatory agencies on a timely basis on terms that are acceptable to us;
- potential changes of federal, state and local statutes and regulations, including environmental requirements that prevent a project from proceeding or increase the anticipated cost of the expansion project;
- our ability to construct projects within anticipated costs, including the risk that we may incur cost overruns resulting from inflation or increased costs of equipment, materials or labor, or other factors beyond our control, that may be material;
- anticipated future growth in natural gas supply does not materialize; and
- lack of transportation, storage or throughput commitments that result in write-offs of development costs.

Any of these risks could prevent a project from proceeding, delay its completion or increase its anticipated costs. As a result, new facilities may not achieve our expected investment return, which could adversely affect our financial position or results of operations.

### Risks Related to Our Affiliation with El Paso

El Paso files reports, proxy statements and other information with the SEC under the Securities Exchange Act of 1934, as amended. Each prospective investor should consider this information and the matters disclosed therein in addition to the matters described in this report. Such information is not incorporated by reference into this report.

***Our relationship with El Paso and its financial condition subjects us to potential risks that are beyond our control.***

Due to our relationship with El Paso, adverse developments or announcements concerning El Paso could adversely affect our financial condition, even if we have not suffered any similar development. The ratings assigned to El Paso's senior unsecured indebtedness are below investment grade, currently rated Caa1 by Moody's Investor Service and B− by Standard & Poor's. The ratings assigned to our senior unsecured indebtedness are currently rated B1 by Moody's Investor Service and B by Standard & Poor's. Downgrades of our credit ratings could increase our cost of capital and collateral requirements, and could impede our access to capital markets.

El Paso provides cash management and other corporate services for us. Pursuant to El Paso's cash management program, surplus cash is made available to El Paso in exchange for an affiliated receivable. In addition, we conduct commercial transactions with some of our affiliates. If El Paso is unable to meet its liquidity needs, there can be no assurance that we will be able to access cash under the cash management program, or that our affiliates would pay their obligations to us. However, we might still be required to satisfy affiliated company payables. Our inability to recover any affiliated receivables owed to us could adversely affect our ability to repay our outstanding indebtedness. For a further discussion of these matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 11.

***Our system of internal controls is designed to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes. A loss of public confidence in the quality of our internal controls or disclosures could have a negative impact on us.***

Our system of internal controls is designed to provide reasonable assurance that the objectives of the control system are met. However, any system of internal controls is subject to inherent limitations and the design of our controls may not provide absolute assurances that all of our objectives will be entirely met. This includes the possibility that controls may be inappropriately circumvented or overridden, that judgments in decision-making can be faulty and that misstatements due to errors or fraud may not be prevented or detected.

***Our subsidiary may be subject to a change of control under certain circumstances.***

Southern Gas Storage Company, our subsidiary, as well as its ownership in Bear Creek is pledged as collateral under El Paso's $3 billion credit agreement. As a result, their ownership is subject to change if there is an event of default under the credit agreement and El Paso's lenders exercise rights over their collateral.

Furthermore, we have indentures governing our long-term debt that have cross-acceleration provisions with $10 million thresholds. If we have any debt in excess of $10 million accelerated for any reason, our long-term debt could be accelerated. The acceleration of our long-term debt could also adversely affect our liquidity position and, in turn, our financial condition.

***We are a wholly owned subsidiary of El Paso.***

El Paso has substantial control over:

- our payment of dividends;
- decisions on our financings and our capital raising activities;

- mergers or other business combinations;
- our acquisitions or dispositions of assets; and
- our participation in El Paso's cash management program.

El Paso may exercise such control in its interests and not necessarily in the interests of us or the holders of our long-term debt.

**Risks Related to Citrus Corp.**

***Florida Gas Transmission Company (FGT) depends substantially upon a small number of customers.***

The five most significant customers on FGT's pipeline system will account for approximately 64 percent of contracted capacity, with the two most significant customers, Florida Power & Light Company and TECO Energy, Inc., including its subsidiaries Tampa Electric Company and Peoples Gas System, Inc., being obligated for approximately 36 percent and 17 percent of such capacity. Accordingly, failure of one or more of FGT's most significant customers to pay reservation charges could reduce its revenues materially and have a material adverse effect on its business, financial condition and results of operations.

***Important actions by Citrus and FGT require approval by both CrossCountry Energy, LLC (CrossCountry) and us.***

El Paso contributed its 50 percent interest in Citrus to us in March 2003. CrossCountry owns the other 50 percent interest in Citrus. Citrus' organizational documents and FGT's organizational documents require that important matters such as the declaration of dividends and similar payments, the approval of operating budgets, the incurrence of indebtedness and the consummation of significant transactions be approved by both CrossCountry and us. Consequently, we are dependent on CrossCountry's agreement to effect any such actions. CrossCountry's interests with respect to these important matters could be different from ours and, accordingly, we may be unable to cause Citrus and FGT to take important actions, such as the payment of dividends and the sale or acquisition of assets.

## ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

## ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for taxes not yet payable, liens incident to minor encumbrances, liens for credit arrangements and easements and restrictions that do not materially detract from the value of these properties, our interest in these properties, or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

## ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 7, and is incorporated herein by reference.

## ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Item 4, Submission of Matters to a Vote of Security Holders, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

## PART II

### ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

All of our common stock, par value $1 per share, is owned by El Paso and, accordingly, our stock is not publicly traded.

We pay dividends on our common stock from time to time from legally available funds that have been approved for payment by our Board of Directors. In March 2003, in connection with El Paso's contribution of its interest in Citrus to us, we declared and paid a $600 million dividend, $310 million of which was a distribution of affiliated receivables and $290 million of which was cash. No common stock dividends were declared or paid in 2005 or 2004.

### ITEM 6. SELECTED FINANCIAL DATA

Item 6, Selected Financial Data, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

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

The information required by this Item is presented in a reduced disclosure format pursuant to General Instruction I to Form 10-K. Our Management's Discussion and Analysis includes forward-looking statements that are subject to risks and uncertainties. Actual results may differ substantially from the statements we make in this section due to a number of factors that are discussed in Part I, Item 1A, Risk Factors.

### Overview

Our business primarily consists of interstate natural gas transmission, storage and LNG terminalling operations. Each of these businesses face varying degrees of competition from other pipelines and proposed LNG facilities, as well as from alternative energy sources used to generate electricity, such as hydroelectric power, coal and fuel oil.

The FERC regulates the rates we can charge our customers. These rates are a function of the costs of providing services to our customers, including a reasonable return on our invested capital. As a result, our revenues and financial results have historically been relatively stable. However, our financial results can be subject to volatility due to factors such as changes in natural gas prices and market conditions, regulatory actions, competition, the creditworthiness of our customers and weather. In 2005, 89 percent of our revenues were attributable to reservation charges paid by firm customers. Reservation charges are paid regardless of volumes transported or stored. The remaining 11 percent were variable. We also experience volatility in our financial results when the amounts of natural gas utilized in operations differ from the amounts we recover from our customers for those purposes.

Our ability to extend existing customer contracts or remarket expiring contracted capacity is dependent on competitive alternatives, the regulatory environment at the federal, state and local levels and market supply and demand factors at the relevant dates these contracts are extended or expire. The duration of new or renegotiated contracts will be affected by current prices, competitive conditions and judgments concerning future market trends and volatility. Subject to regulatory requirements, we attempt to recontract or remarket our capacity at the rates allowed under our tariffs, although at times, we discount these rates to remain competitive. Our existing contracts mature at various times and in varying amounts of throughput capacity. We continue to manage our recontracting process to mitigate the risk of significant impacts on our revenues. The weighted average remaining contract term for active contracts is approximately six years as of December 31, 2005.

Below is the contract expiration portfolio for our firm transportation contracts as of December 31, 2005:

| | BBtu/d | Percent of Total Contracted Capacity |
|---|---|---|
| 2006 | 187 | 5 |
| 2007 | 162 | 5 |
| 2008 | 69 | 2 |
| 2009 and beyond | 3,199 | 88 |

### Results of Operations

Our management, as well as El Paso's management, uses earnings before interest expense and income taxes (EBIT) to assess the operating results and effectiveness of our business. We define EBIT as net income adjusted for (i) items that do not impact our income from continuing operations, (ii) income taxes and (iii) interest, which includes interest and debt expense and affiliated interest income. Our business consists of consolidated operations as well as investments in unconsolidated affiliates. We exclude interest from this measure so that our investors may evaluate our operating results without regard to our financing methods. We believe EBIT is useful to our investors because it allows them to more effectively evaluate the operating performance of both our consolidated business and our unconsolidated investments using the same performance measure analyzed internally by our management. EBIT may not be comparable to measurements used by other companies. Additionally, EBIT should be considered in conjunction with net income and other performance measures such as operating income or operating cash flows. The following is a reconciliation of EBIT to net income for the years ended December 31:

| | 2005 | 2004 |
|---|---|---|
| | (In millions, except volume amounts) | |
| Operating revenues | $ 477 | $ 527 |
| Operating expenses | (249) | (281) |
| Operating income | 228 | 246 |
| Earnings from unconsolidated affiliates | 80 | 78 |
| Other income, net | 22 | 9 |
| EBIT | 330 | 333 |
| Interest and debt expense | (93) | (94) |
| Affiliated interest income | 11 | 4 |
| Income taxes | (74) | (74) |
| Net income | $ 174 | $ 169 |
| Throughput volumes (BBtu/d)[1] | 2,942 | 3,170 |

[1] Throughput volumes include volumes associated with our proportionate share of our 50 percent equity interest in Citrus and billable transportation throughput volumes for storage injection.

The following items contributed to our overall EBIT decrease of $3 million for the year ended December 31, 2005 as compared to 2004:

| | Revenue | Expense | Other | EBIT Impact |
|---|---|---|---|---|
| | Favorable/(Unfavorable) (In millions) | | | |
| Gas not used in operations and other natural gas sales | $(64) | $49 | $ — | $(15) |
| Higher general and administrative expenses | — | (8) | — | (8) |
| Hurricanes Katrina and Rita | — | (8) | — | (8) |
| Gain on sale of assets in 2005 | — | 9 | — | 9 |
| Mainline expansions | 11 | (1) | (3) | 7 |
| Elba Island expansion | — | — | 8 | 8 |
| Other[1] | 3 | (9) | 10 | 4 |
| Total impact on EBIT | $(50) | $32 | $ 15 | $ (3) |

[1] Consists of individually insignificant items.

The following provides further discussions on some of the significant items listed above as well as events that may affect our operations in the future.

*Gas Not Used in Operations and Other Natural Gas Sales.* The financial impact of operational gas, net of gas used in operations, is based on the amount of natural gas we are allowed to retain and dispose of according to our tariff, relative to the amounts of natural gas we use for operating purposes and the price of natural gas. Gas not used in operations results in revenues to us, which are impacted by volumes and prices during a given period. Prior to March 2005, the effective date of our rate case settlement, we recognized revenues on gas not used in operations at the time gas was sold. In March 2005, we began recognizing revenues on gas not used in operations when the volumes are retained according to our tariff. During 2004 and 2005, the volumes of natural gas not utilized for operations were based on factors such as system throughput, facility enhancements and the ability to operate the system in the most efficient and safe manner. As a result of our rate case settlement, the volumes of natural gas that we retain were reduced, which resulted in a reduction in revenues in 2005 versus 2004. We anticipate that revenue from this area of our business will continue to vary in the future and will be reduced by our recently approved rate case settlement, which includes a sharing mechanism with our customers for volumes retained in excess of what we use. Our revenues will also continue to be affected by the efficiency of our pipeline operations, the price of natural gas and other factors.

*Higher General and Administrative Expenses.* During the year ended December 31, 2005, our general and administrative expenses were higher than in 2004, primarily due to an increase in benefits accrued under retirement plans, higher insurance and professional fees and higher corporate overhead allocations from El Paso. El Paso's allocation to us increased in 2005 based on the estimated level of effort devoted to our operations and the relative size of our EBIT, gross property and payroll. We are also allocated costs from TGP associated with our shared pipeline services.

*Hurricanes Katrina and Rita.* In 2005, we incurred significant damage to sections of our pipeline facilities due to Hurricanes Katrina and Rita. These hurricanes had substantial impacts on offshore producers in the Gulf of Mexico Region resulting in the shut-in of a significant portion of offshore production in the affected areas. Hurricane Katrina resulted in the initial shut-in of all gas supplies upstream of our Toca Compressor Station (East Leg), which were flowing at a rate of approximately 0.5 Bcf/d prior to the hurricane. Hurricane Rita caused damage at three additional receipt meter stations on our West Leg, which were flowing at a rate of approximately 0.1 Bcf/d prior to the hurricane. In addition, there was damage to other pipelines that were also flowing approximately 0.3 Bcf/d into our system. West Leg repairs have been completed and gas supply has returned to pre-Katrina levels. East Leg repairs are on-going and gas supply is near the levels that were flowing pre-Katrina. Hurricane Katrina adversely impacted our results by approximately $8 million during the fourth quarter of 2005. We continue to evaluate the impact these hurricanes will have on our 2006 financial statements as a result of delayed repairs, higher maintenance costs, potential demand charge credits and lost revenues associated with reductions in interruptible services.

*Gain on the Sale of Assets.* In 2005, we recorded a gain of $7 million on the sale of pipeline and measurement facilities to Atlanta Gas Light Company and a gain of $2 million on the sale of a gathering system.

*Mainline Expansions.* Our mainline expansions consist of three major projects that were phased into service from June 2002 through August 2004. The increase in expansion revenue from these projects was partially offset by depreciation on the new facilities and the elimination of earnings associated with an allowance for funds used during construction (AFUDC).

In addition, in November 2005, the FERC issued a preliminary determination that approved our Cypress expansion project to construct an additional 176 miles to our mainline system, which will increase our capacity by 500 MMcf/d. The expansion is estimated to cost approximately $321 million and will be phased in service over a four year period beginning in May 2007. Construction is expected to begin in May 2006, following the issuance of final certificate authorization by the FERC. This expansion is currently estimated to increase our revenues by approximately $62 million annually. Estimated revenues represent executed precedent agreements with third parties for capacity on the expansion project.

*Elba Island Expansion.* The Elba Island LNG expansion, which we completed in February 2006, increased the peak sendout capacity to 1,215 MMcf/d and the base load sendout capacity of the facility to 806 MMcf/d. This expansion is estimated to increase our revenues by $29 million annually. The capitalized AFUDC on amounts expended on this project had a favorable impact to our EBIT.

*Accounting for Pipeline Integrity Costs.* Beginning January 1, 2006, we will be required under a FERC accounting release to expense certain costs incurred in connection with our pipeline integrity program, instead of our current practice of capitalizing them as part of our property, plant and equipment. We currently estimate that we will be required to expense an additional amount of pipeline integrity costs under the release in the range of approximately $4 million to $6 million annually.

*Affiliated Interest Income*

Affiliated interest income for the year ended December 31, 2005, was $7 million higher than in 2004 due primarily to higher average advances to El Paso under its cash management program and higher average short-term interest rates. The average advances due from El Paso of $140 million in 2004 increased to

$256 million in 2005. In addition, the average short-term interest rates increased from 2.4% in 2004 to 4.2% in 2005.

*Income Taxes*

| | Year Ended December 31, | |
|---|---|---|
| | 2005 | 2004 |
| | (In millions, except for rates) | |
| Income taxes | $74 | $74 |
| Effective tax rate | 30% | 30% |

Our effective tax rates were lower than the statutory rate of 35 percent in both periods primarily due to the tax effect of earnings from unconsolidated affiliates where we anticipate receiving dividends that qualify for the dividends received deduction, partially offset by the effect of state income taxes. For a reconciliation of the statutory rate to the effective rates, see Item 8, Financial Statements and Supplementary Data, Note 2.

## Liquidity and Capital Expenditures

*Liquidity Overview*

Our liquidity needs are provided by cash flows from operating activities. In addition, we participate in El Paso's cash management program. Under El Paso's cash management program, depending on whether we have short-term cash surpluses or requirements, we either provide cash to El Paso or El Paso provides cash to us in exchange for an affiliated note receivable or payable. We have historically provided cash advances to El Paso, and we reflect these advances as investing activities in our statement of cash flows. At December 31, 2005, we had a note receivable from El Paso of $272 million that is due upon demand. However, we do not anticipate settlement within the next twelve months and therefore, classified this receivable as non-current on our balance sheet. See Item 8, Financial Statements and Supplementary Data, Note 11, for a further discussion of El Paso's cash management program.

In addition to the cash management program, we have notes receivable from El Paso of $67 million. We believe that cash flows from operating activities and amounts available under El Paso's cash management program, if necessary, will be adequate to meet our short-term capital requirements for our existing operations and planned expansion opportunities.

*Capital Expenditures*

Our capital expenditures for the years ended December 31 are as follows:

| | 2005 | 2004 |
|---|---|---|
| | (In millions) | |
| Maintenance | $ 67 | $ 69 |
| Expansion/Other | 76 | 122 |
| Hurricanes | 34[1] | 8 |
| Total | $177 | $199 |

[1] Amount shown is net of insurance proceeds of $43 million.

Under our current plan, we expect to spend between approximately $61 million and $79 million in each of the next three years for capital expenditures, primarily to maintain the integrity of our pipeline, to comply with clean air regulations and to ensure the safe and reliable delivery of natural gas to our customers. In addition, we have budgeted to spend between $80 million and $145 million in each of the next three years to expand the capacity and services of our system for long-term contracts. We expect to fund our capital expenditures through a combination of internally generated funds or by recovering some of the amounts advanced to El Paso under its cash management program, if necessary.

We continue to assess the damage caused by Hurricanes Katrina and Rita. We are part of a mutual insurance company, and are subject to certain individual and aggregate loss limits by event. The mutual insurance company indicated that aggregate losses for both Hurricanes Katrina and Rita will exceed the per claim limits allowed under the program. As a result, we will not receive insurance recoveries on some of the costs we incur, which will impact our liquidity or financial results. In addition, the timing of our replacements of the damaged property and equipment may differ from the related insurance reimbursement, which could impact our liquidity from period to period. Total costs incurred as of 2005, our estimate of future costs and insurance reimbursements of these costs are shown below:

| | | Projected Costs | | | |
|---|---|---|---|---|---|
| Hurricane | Total Costs Incurred as of the Year Ended December 31, 2005 | Operations and Maintenance | Capital | Anticipated Reimbursement | Insurance Reimbursement Received |
| | (In millions, except for percent) | | | | |
| Ivan | $ 69 | $— | $— | 100% | $53 |
| Katrina | 34 | 12 | 97[1] | 41% | — |
| Total | $103 | $12 | $97 | | $53 |

[1] Include $11 million of non-insurable costs.

## Commitments and Contingencies

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 7, which is incorporated herein by reference.

## New Accounting Pronouncements Issued But Not Yet Adopted

See Item 8, Financial Statements and Supplementary Data, Note 1, under *New Accounting Pronouncements Issued But Not Yet Adopted*, which is incorporated herein by reference.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our primary market risk is exposure to changing interest rates. The table below shows the carrying value and related weighted average effective interest rates of our interest bearing securities by expected maturity dates and the fair value of those securities. At December 31, 2005, the fair values of our fixed rate long-term debt securities have been estimated based on quoted market prices for the same or similar issues.

| | December 31, 2005 | | | | | | December 31, 2004 | |
|---|---|---|---|---|---|---|---|---|
| | Expected Fiscal Year of Maturity of Carrying Amounts | | | | | | | |
| | 2007 | 2008 | 2010 | Thereafter | Total | Fair Value | Carrying Amount | Fair Value |
| | (In millions, except for rates) | | | | | | | |
| **Liabilities:** | | | | | | | | |
| Long-term debt — fixed rate | $100 | $100 | $397 | $598 | $1,195 | $1,277 | $1,195 | $1,302 |
| Average interest rate . . . | 6.8% | 6.3% | 9.1% | 7.7% | | | | |

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

### SOUTHERN NATURAL GAS COMPANY

### CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME
**(In millions)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Operating revenues | $477 | $527 | $482 |
| Operating expenses | | | |
| Operation and maintenance | 177 | 206 | 185 |
| Depreciation, depletion and amortization | 51 | 50 | 47 |
| Gain on sale of long-lived assets | (9) | — | — |
| Taxes, other than income taxes | 30 | 25 | 21 |
| | 249 | 281 | 253 |
| Operating income | 228 | 246 | 229 |
| Earnings from unconsolidated affiliates | 80 | 78 | 55 |
| Other income, net | 22 | 9 | 11 |
| Interest and debt expense | (93) | (94) | (87) |
| Affiliated interest income | 11 | 4 | 4 |
| Income before income taxes | 248 | 243 | 212 |
| Income taxes | 74 | 74 | 68 |
| Net income | $174 | $169 | $144 |
| Other comprehensive income | 2 | — | — |
| Comprehensive income | $176 | $169 | $144 |

See accompanying notes.

## SOUTHERN NATURAL GAS COMPANY

## CONSOLIDATED BALANCE SHEETS
**(In millions, except share amounts)**

| | December 31, 2005 | December 31, 2004 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Cash and cash equivalents | $ — | $ — |
| Accounts receivable | | |
| Customer, net of allowance of $1 in 2005 and $3 in 2004 | 58 | 80 |
| Other | 5 | — |
| Materials and supplies | 12 | 11 |
| Deferred income taxes | 9 | 4 |
| Other | 17 | 5 |
| Total current assets | 101 | 100 |
| Property, plant and equipment, at cost | 3,369 | 3,234 |
| Less accumulated depreciation, depletion and amortization | 1,368 | 1,344 |
| Total property, plant and equipment, net | 2,001 | 1,890 |
| Other assets | | |
| Investments in unconsolidated affiliates | 697 | 740 |
| Notes receivable from affiliate | 339 | 171 |
| Other | 52 | 62 |
| | 1,088 | 973 |
| Total assets | $3,190 | $2,963 |
| **LIABILITIES AND STOCKHOLDER'S EQUITY** | | |
| Current liabilities | | |
| Accounts payable | | |
| Trade | $ 40 | $ 36 |
| Affiliates | 17 | 8 |
| Other | 12 | 2 |
| Taxes payable | 67 | 58 |
| Accrued interest | 30 | 30 |
| Other | 11 | 6 |
| Total current liabilities | 177 | 140 |
| Long-term debt | 1,195 | 1,195 |
| Other liabilities | | |
| Deferred income taxes | 320 | 296 |
| Other | 44 | 54 |
| | 364 | 350 |
| Commitments and contingencies | | |
| Stockholder's equity | | |
| Common stock, par value $1 per share; 1,000 shares authorized, issued and outstanding | — | — |
| Additional paid-in capital | 340 | 340 |
| Retained earnings | 1,120 | 946 |
| Accumulated other comprehensive loss | (6) | (8) |
| Total stockholder's equity | 1,454 | 1,278 |
| Total liabilities and stockholder's equity | $3,190 | $2,963 |

See accompanying notes.

## SOUTHERN NATURAL GAS COMPANY

## CONSOLIDATED STATEMENTS OF CASH FLOWS
**(In millions)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2005 | 2004 | 2003 |
| Cash flows from operating activities | | | |
| Net income | $174 | $ 169 | $ 144 |
| Adjustments to reconcile net income to net cash from operating activities | | | |
| Depreciation, depletion and amortization | 51 | 50 | 47 |
| Deferred income tax expense | 19 | 26 | 31 |
| Gain on sale of long-lived assets | (9) | — | — |
| Earnings from unconsolidated affiliates, adjusted for cash distributions | 45 | (8) | (54) |
| Other non-cash income items | (8) | (3) | — |
| Asset and liability changes | | | |
| Accounts receivable | 18 | 3 | (10) |
| Accounts payable | 18 | 3 | (4) |
| Taxes payable | 6 | — | 11 |
| Other asset and liability changes | | | |
| Assets | (8) | (12) | (8) |
| Liabilities | 2 | (11) | 10 |
| Net cash provided by operating activities | 308 | 217 | 167 |
| Cash flows from investing activities | | | |
| Additions to property, plant and equipment | (177) | (199) | (237) |
| Net change in affiliate advances | (168) | (18) | (33) |
| Proceeds from the sale of assets | 32 | — | — |
| Net change in restricted cash | 5 | (1) | (9) |
| Other | — | 1 | 18 |
| Net cash used in investing activities | (308) | (217) | (261) |
| Cash flows from financing activities | | | |
| Net proceeds from the issuance of long-term debt | — | — | 384 |
| Dividends paid | — | — | (290) |
| Net cash provided by financing activities | — | — | 94 |
| Net change in cash and cash equivalents | — | — | — |
| Cash and cash equivalents | | | |
| Beginning of period | — | — | — |
| End of period | $ — | $ — | $ — |

See accompanying notes.

## SOUTHERN NATURAL GAS COMPANY

## CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY
**(In millions, except share amounts)**

| | Common stock | | Additional paid-in capital | Retained earnings | Accumulated other comprehensive loss | Total stockholder's equity |
|---|---|---|---|---|---|---|
| | Shares | Amount | | | | |
| January 1, 2003 | 1,000 | $ — | $341 | $1,233 | $ (8) | $1,566 |
| Net income | | | | 144 | | 144 |
| Allocated tax expense of El Paso equity plans | | | (1) | | | (1) |
| Dividends | | | | (600) | | (600) |
| December 31, 2003 | 1,000 | — | 340 | 777 | (8) | 1,109 |
| Net income | | | | 169 | | 169 |
| December 31, 2004 | 1,000 | — | 340 | 946 | (8) | 1,278 |
| Net income | | | | 174 | | 174 |
| Other comprehensive income | | | | | 2 | 2 |
| December 31, 2005 | 1,000 | $ — | $340 | $1,120 | $ (6) | $1,454 |

See accompanying notes.

## SOUTHERN NATURAL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### 1. Basis of Presentation and Summary of Significant Accounting Policies

*Basis of Presentation and Principles of Consolidation*

Our consolidated financial statements include the accounts of all majority owned and controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. We consolidate entities when we either (i) have the ability to control the operating and financial decisions and policies of that entity or (ii) are allocated a majority of the entity's losses and/or returns through our variable interests in that entity. The determination of our ability to control or exert significant influence over an entity and whether we are allocated a majority of the entity's losses and/or returns involves the use of judgment. We apply the equity method of accounting where we can exert significant influence over, but do not control, the policies and decisions of an entity and where we are not allocated a majority of the entity's losses and/or returns. We use the cost method of accounting where we are unable to exert significant influence over the entity. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications had no impact on reported net income or stockholder's equity.

*Use of Estimates*

The preparation of financial statements in conformity with accounting principles generally accepted in the U.S. requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

*Regulated Operations*

Our natural gas transmission system, storage and LNG terminalling operations are subject to the jurisdiction of the FERC in accordance with the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005, and we currently apply the provisions of Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* We perform an annual study to assess the ongoing applicability of SFAS No. 71. The accounting required by SFAS No. 71 differs from the accounting required for businesses that do not apply its provisions. Transactions that are generally recorded differently as a result of applying regulatory accounting requirements include postretirement employee benefit plan costs, capitalizing an equity return component on regulated capital projects and certain costs included in, or expected to be included in, future rates.

*Cash and Cash Equivalents*

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

We maintain cash on deposit with banks that is pledged for a particular use or restricted to support a potential liability. We classify these balances as restricted cash in other current or non-current assets in our balance sheet based on when we expect this cash to be used. We had $5 million of restricted cash in current assets as of December 31, 2005, and we had $10 million of restricted cash in non-current assets as of December 31, 2004.

*Allowance for Doubtful Accounts*

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of an outstanding receivable balance. We regularly review collectibility and establish or adjust our allowance as necessary using the specific identification method.

*Materials and Supplies*

We value materials and supplies at the lower of cost or market value with cost determined using the average cost method.

*Natural Gas Imbalances*

Natural gas imbalances generally occur when the actual amount of natural gas received on a customer's contract at the supply point differs from the actual amount of natural gas delivered under the customer's transportation contract at the delivery point. We value imbalances due to or from shippers at specified index prices set forth in our tariff based on the production month in which the imbalances occur. Customer imbalances are aggregated and netted (by customer) on a monthly basis, and settled in cash, subject to the terms of our tariff. For differences in value between the amounts we pay or receive for the purchase or sale of gas used to resolve shipper imbalances over the course of a year, we have the right under our tariff to recover applicable losses through a storage cost reconciliation charge. This charge is applied to volumes as they are transported on our system. Annually, we true-up any losses or gains obtained during the year by adjusting the following years' storage cost reconciliation charge.

Imbalances due from others are reported in our balance sheet as either accounts receivable from customers or accounts receivable from affiliates. Imbalances owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to affiliates. In addition, we classify all imbalances as current as we expect to settle them within a year.

*Property, Plant and Equipment*

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at either the fair value of the assets acquired or the cost to the entity that first placed the asset in service. For assets we construct, we capitalize direct costs, such as labor and materials, and indirect costs, such as overhead, interest and an equity return component, as allowed by the FERC. We capitalize the major units of property replacements or improvements and expense minor items.

We use the composite (group) method to depreciate property, plant and equipment. Under this method, assets with similar lives and characteristics are grouped and depreciated as one asset. We apply the FERC-accepted depreciation rate to the total cost of the group until its net book value equals its salvage value. Currently, our depreciation rates vary from less than one percent to 20 percent per year. Using these rates, the remaining depreciable lives of these assets range from two to 57 years. We re-evaluate depreciation rates each time we file with the FERC for a change in our transportation and storage service rates.

When we retire property, plant and equipment, we charge accumulated depreciation and amortization for the original cost, plus the cost to remove, sell or dispose, less its salvage value. We do not recognize a gain or loss unless we sell an entire operating unit. We include gains or losses on dispositions of operating units in operating income.

At December 31, 2005 and 2004, we had approximately $182 million and $129 million of construction work in progress included in our property, plant and equipment.

We capitalize a carrying cost or AFUDC on funds invested in our construction of long-lived assets. This carrying cost consists of a return on the investment financed by debt and a return on the investment financed by equity. The debt portion is calculated based on our average cost of debt. Debt amounts capitalized during the years ended December 31, 2005, 2004 and 2003, were $5 million, $3 million and $3 million. These debt amounts are included as a reduction to interest expense in our income statement. The equity portion of capitalized costs is calculated using the most recent FERC-approved equity rate of return. The equity amounts capitalized during the years ended December 31, 2005, 2004 and 2003, were $10 million, $6 million and $7 million (exclusive of any tax related impacts). These equity amounts are included as other non-operating income on our income statement. Capitalized carrying costs for debt and equity financed construction are reflected as an increase in the cost of the asset on our balance sheet.

*Asset and Investment Impairments*

We evaluate our assets and investments for impairment when events or circumstances indicate that their carrying values may not be recovered. These events include market declines that are believed to be other than temporary, changes in the manner in which we intend to use a long-lived asset, decisions to sell an asset or investment and adverse changes in the legal or business environment such as adverse actions by regulators. When an event occurs, we evaluate the recoverability of our carrying values based on either (i) our long-lived assets' ability to generate future cash flows on an undiscounted basis or (ii) the fair value of our investments in unconsolidated affiliates. If an impairment is indicated or if we decide to sell a long-lived asset or group of assets, we adjust the carrying value of these assets downward, if necessary, to their estimated fair value, less costs to sell. Our fair value estimates are generally based on market data obtained through the sales process or an analysis of expected discounted cash flows. The magnitude of any impairments are impacted by a number of factors, including the nature of the assets being sold and our established time frame for completing the sales, among other factors.

*Revenue Recognition*

Our revenues are generated from transportation, storage and LNG terminalling services as well as sales of natural gas. For our transportation and storage services, we recognize reservation revenues on firm contracted capacity ratably over the contract period regardless of the amount of natural gas that is transported or stored. For interruptible or volumetric-based services, we record revenues when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage facility. Gas not used in operations is based on the volumes of natural gas we are allowed to retain and dispose of relative to the amounts we use for operating purposes. Prior to March 2005, the effective date of our rate case settlement, we recognized revenues on gas not used in operations at the time gas was sold. In March 2005, we began recognizing revenues on gas not used in operations when the volumes are retained according to our tariff. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a price specified in the contract. We are subject to FERC regulations and, as a result, revenues we collect may be subject to refund in a rate proceeding. We establish reserves for these potential refunds.

*Price Risk Management Activities*

Our equity investee, Citrus, uses derivatives to mitigate, or hedge, cash flow risk associated with its variable interest rates on long-term debt. Citrus accounts for these derivatives under the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, and records changes in the fair value of these derivatives in other comprehensive income. We reflect our proportionate share of the impact these derivative instruments have on Citrus' financial statements as adjustments to our other comprehensive income and our investment in unconsolidated affiliates.

*Environmental Costs and Other Contingencies*

We record liabilities at their undiscounted amounts on our balance sheet in other current and long-term liabilities when our environmental assessments indicate that remediation efforts are probable and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the EPA or other organizations. Our estimates are subject to revision in future periods based on actual costs or new circumstances. We capitalize costs that benefit future periods and we recognize a current period expense when clean-up efforts do not benefit future periods.

We evaluate separately from our liability any amounts paid directly or reimbursed by government sponsored programs and potential recoveries or reimbursements of remediation costs from third parties including insurance coverage. When recovery is assured after an evaluation of their creditworthiness or solvency, we record and report an asset separately from the associated liability on our balance sheet.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against the associated reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

*Income Taxes*

El Paso maintains a tax accrual policy to record both regular and alternative minimum taxes for companies included in its consolidated federal and state income tax returns. The policy provides, among other things, that (i) each company in a taxable income position will accrue a current expense equivalent to its federal and state income taxes, and (ii) each company in a tax loss position will accrue a benefit to the extent its deductions, including general business credits, can be utilized in the consolidated returns. El Paso pays all consolidated U.S. federal and state income taxes directly to the appropriate taxing jurisdictions and, under a separate tax billing agreement, El Paso may bill or refund its subsidiaries for their portion of these income tax payments.

Pursuant to El Paso's policy, we record current income taxes based on our taxable income and we provide for deferred income taxes to reflect estimated future tax payments or receipts. Deferred taxes represent the tax impacts of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in the recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

*Accounting for Asset Retirement Obligations*

On January 1, 2003, we adopted SFAS No. 143, *Accounting for Asset Retirement Obligations,* which requires that we record a liability for retirement and removal costs of long-lived assets used in our business when the timing and/or amount of the settlement of those costs are relatively certain. On December 31, 2005, we adopted the provisions of FASB Interpretation (FIN) No. 47, *Accounting for Conditional Asset Retirement Obligations,* which requires that we record a liability for those retirement and removal costs in which the timing and/or amount of the settlement of the costs are uncertain.

We have legal obligations associated with our natural gas pipeline and related transmission facilities and storage wells. We have obligations to plug storage wells when we no longer plan to use them and when we abandon them. Our legal obligations associated with our natural gas transmission facilities relate primarily to purging and sealing the pipeline if it is abandoned. We also have obligations to remove hazardous materials associated with our natural gas transmission facilities if they are replaced. We accrue a liability on those legal obligations when we can estimate the timing and amount of their settlement. These obligations include those where we have plans to or otherwise will be legally required to replace, remove or retire the associated assets. Our natural gas pipeline can be maintained indefinitely and, as a result, we have not accrued a liability associated with purging and sealing it. Our net asset retirement liability as of December 31, 2005 and 2004, is not material to our financial statements.

*New Accounting Pronouncement Issued But Not Yet Adopted*

As of December 31, 2005, there were several accounting standards and interpretations that had not yet been adopted by us. Below is a discussion of a significant standard that may impact us.

*Accounting for Pipeline Integrity Costs.* Beginning January 1, 2006, we will be required under a FERC accounting release to expense certain costs incurred in connection with our pipeline integrity program instead of our current practice of capitalizing them as part of our property, plant and equipment. We currently estimate that we will be required to expense an additional amount of pipeline integrity costs under the release in the range of approximately $4 million and $6 million annually.

## 2. Income Taxes

*Components of Income Taxes.* The following table reflects the components of income taxes included in net income for each of the three years ended December 31:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| | | (In millions) | |
| Current | | | |
| Federal | $48 | $42 | $31 |
| State | 7 | 6 | 6 |
| | 55 | 48 | 37 |
| Deferred | | | |
| Federal | 18 | 22 | 28 |
| State | 1 | 4 | 3 |
| | 19 | 26 | 31 |
| Total income taxes | $74 | $74 | $68 |

*Effective Tax Rate Reconciliation.* Our income taxes differ from the amount computed by applying the statutory federal income tax rate of 35 percent for the following reasons for each of the three years ended December 31:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| | | (In millions, except for rates) | |
| Income taxes at the statutory federal rate of 35% | $87 | $ 85 | $ 74 |
| Increase (decrease) | | | |
| State income taxes, net of federal income tax benefit | 5 | 6 | 6 |
| Earnings from unconsolidated affiliates where we anticipate receiving dividends | (18) | (17) | (12) |
| Income taxes | $74 | $ 74 | $ 68 |
| Effective tax rate | 30% | 30% | 32% |

*Deferred Tax Assets and Liabilities.* The following are the components of our net deferred tax liability at December 31:

| | 2005 | 2004 |
|---|---|---|
| | (In millions) | |
| Deferred tax liabilities | | |
| Property, plant and equipment | $294 | $265 |
| Investment in unconsolidated affiliates | 25 | 28 |
| Other | 35 | 45 |
| Total deferred tax liability | 354 | 338 |
| Deferred tax assets | | |
| U.S. net operating loss and tax credit carryovers | 2 | 7 |
| Other | 42 | 40 |
| Valuation allowance | (1) | (1) |
| Total deferred tax asset | 43 | 46 |
| Net deferred tax liability | $311 | $292 |

*Tax Carryovers.* The following are the components of our tax carryovers as of December 31, 2005:

| | Amount | Expiration Year |
|---|---|---|
| | (In millions) | |
| General business credit | $1 | 2016-2022 |
| Net operating loss | 2 | 2019-2021 |

Usage of these carryovers is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation year rules of IRS regulations. We have recorded a valuation allowance to reserve for the deferred taxes related to our general business credits.

*Valuation Allowances.* Deferred tax assets are recorded on net operating losses and temporary differences in the book and tax basis of assets and liabilities expected to produce tax deductions in future periods. The realization of these assets depends on recognition of sufficient future taxable income in specific tax jurisdictions during periods in which those temporary differences or net operating losses are deductible. In assessing the need for a valuation allowance on our deferred tax assets, we consider whether it is more likely than not that some portion or all of them will not be realized. We believe it is more likely than not that we will realize the benefit of our deferred tax assets, net of any existing valuation allowances, due to the effect of future reversals of existing taxable temporary differences primarily related to depreciation.

*Other Tax Matters.* Under El Paso's tax accrual policy, we are allocated the tax effects associated with our employees' nonqualified dispositions of El Paso stock under its employee stock purchase plan, the exercise of stock options and the vesting of restricted stock as well as restricted stock dividends. This allocation was not significant in 2005 and 2004; however, it increased taxes payable by $1 million in 2003. These tax effects are included in additional paid-in capital in our balance sheets.

## 3. Financial Instruments

The carrying amounts and estimated fair values of our financial instruments are as follows at December 31:

| | 2005 | | 2004 | |
|---|---|---|---|---|
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| | (In millions) | | | |
| Balance sheet financial instruments: | | | | |
| Long-term debt[1] | $1,195 | $1,277 | $1,195 | $1,302 |

(1) We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues.

At December 31, 2005 and 2004, the carrying amounts of cash and cash equivalents, and trade receivables and payables are representative of fair value because of the short-term maturity of these instruments.

## 4. Regulatory Assets and Liabilities

Below are the details of our regulatory assets and liabilities at December 31:

| Description | 2005 | 2004 |
|---|---|---|
| | (In millions) | |
| Non-current regulatory assets | | |
| Deferred taxes on capitalized funds used during construction | $44 | $38 |
| Other | 2 | 3 |
| Total non-current regulatory assets[1] | $46 | $41 |
| Non-current regulatory liabilities | | |
| Cost of removal of offshore assets | $15 | $18 |
| Excess deferred federal income taxes | 2 | 2 |
| Other | 3 | — |
| Total non-current regulatory liabilities[1] | $20 | $20 |

(1) Amounts are included as other non-current assets and liabilities in our balance sheet.

## 5. Accounting for Hedging Activities

As of December 31, 2005 and 2004, our accumulated other comprehensive loss consisted of an unrealized loss of $6 million and $8 million, net of income taxes related to our proportionate interest in the value of Citrus' cash flow hedges. This amount will be reclassified to earnings over the terms of Citrus' outstanding debt. We estimate that $2 million of this unrealized loss will be reclassified from accumulated other comprehensive loss over the next twelve months. For the years ended December 31, 2005, 2004 and 2003, no ineffectiveness was recorded in earnings related to these cash flow hedges.

## 6. Debt and Credit Facilities

*Debt*

Our long-term debt outstanding consisted of the following at December 31:

| | 2005 | 2004 |
|---|---|---|
| | (In millions) | |
| 6.70% Notes due 2007 | $ 100 | $ 100 |
| 6.125% Notes due 2008 | 100 | 100 |
| 8.875% Notes due 2010 | 400 | 400 |
| 7.35% Notes due 2031 | 300 | 300 |
| 8.0% Notes due 2032 | 300 | 300 |
| | 1,200 | 1,200 |
| Less: Unamortized discount | 5 | 5 |
| Long-term debt | $1,195 | $1,195 |

Aggregate maturities of the principal amounts of long-term debt for the next 5 years and in total thereafter are as follows:

| Year | (In millions) |
|---|---|
| 2007 | $ 100 |
| 2008 | 100 |
| 2010 | 400 |
| Thereafter | 600 |
| Total maturities of long-term debt | $1,200 |

We have the ability to call $1.0 billion of our notes at any time prior to their stated maturity date. If we were to exercise our option to call these notes, we would be obligated to pay principal, accrued interest and a make-whole premium to redeem the debt. At this time, we have no intent to call this debt.

*Credit Facilities*

El Paso maintains a $3 billion credit agreement. We are not a borrower under the credit agreement; however, one of our subsidiaries, Southern Gas Storage Company, and our ownership interest in Bear Creek, are pledged as collateral under the agreement. At December 31, 2005, El Paso had $1.2 billion outstanding as a term loan and $1.7 billion of letters of credit issued under the credit agreement.

Under our indentures, we are subject to a number of restrictions and covenants. The most restrictive of these include (i) limitations on the incurrence of additional debt, based on a ratio of debt to EBITDA (as defined in the agreements), the most restrictive of which shall not exceed 6 to 1; (ii) limitations on the use of proceeds from borrowings; (iii) limitations, in some cases, on transactions with our affiliates; (iv) limitations on the incurrence of liens; (v) potential limitations on our ability to declare and pay dividends; and (vi) potential limitations on our ability to participate in El Paso's cash management program discussed in Note 11. For the year ended December 31, 2005, we were in compliance with all of our debt-related covenants.

## 7. Commitments and Contingencies

*Legal Proceedings*

*Grynberg.* In 1997, we and a number of our affiliates were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to underreport the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties due to the alleged mismeasurement. The plaintiff seeks royalties, along with interest, expenses, and punitive damages. The plaintiff also seeks injunctive relief with regard to future gas measurement practices. No monetary relief has been specified in this case. These matters have been consolidated for pretrial purposes *(In re: Natural Gas Royalties Qui Tam Litigation*, U.S. District Court for the District of Wyoming, filed June 1997). Motions to dismiss were argued before a representative appointed by the court. In May 2005, the representative issued a recommendation, which if adopted by the district court judge, will result in the dismissal on jurisdictional grounds of the suit against us. If the district court judge adopts the representative's recommendation, an appeal by the plaintiff of the district court's order is likely. Our costs and legal exposure related to these lawsuits and claims are not currently determinable.

*Royalty Claim.* In five contract settlements reached in the late 1980s with Elf Aquitaine (Elf) pertaining to the pricing of gas produced from certain federal offshore blocks, we indemnified Elf against royalty claims that potentially could have been asserted by the Minerals Management Service (MMS). Following its settlements with us, Elf received demands from MMS for royalty payments related to the settlements. With our approval, Elf protested the demands for over a decade while trying to reach a settlement with the MMS. Elf, which is now TOTAL E&P USA (TOTAL), advised us that it had renewed efforts to settle claims by the MMS for excess royalties attributable to price reductions that we achieved in the gas contract settlements in the late 1980s. TOTAL informed us that the MMS is claiming royalties in excess of $13 million, a large portion of which is interest, for the five settlements with us. We have advised TOTAL that not all of the amounts sought by the MMS are covered by our indemnity. If TOTAL cannot resolve these claims administratively with MMS, then an appeal can be taken to the federal courts. We have the right under a pre-existing settlement with our customers to recover a portion of the amount ultimately paid under the royalty indemnity with TOTAL through a surcharge payable by our customers.

In addition to the above matters, we and our subsidiaries and affiliates are also named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business.

For each of our outstanding legal matters, we evaluate the merits of the case, our exposure to the matter, possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we establish the necessary accruals. As further information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our current reserves are adequate. At December 31, 2005, we had accrued approximately $2 million for our outstanding legal matters.

*Environmental Matters*

We are subject to federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. At December 31, 2005, we had accrued less than $1 million for expected remediation costs and associated onsite, offsite and groundwater technical studies. Our accrual was based on the most likely outcome that can be reasonably estimated.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties related to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe our reserves are adequate.

*Rate Investigation*

In December 2004, SLNG filed a cost and revenue study with the FERC to justify its existing rates for terminaling service at its LNG marine receiving terminal at Elba Island. In September 2005, the FERC approved our settlement offer that resolved all issues in this proceeding. The settlement provides for continuation of current rates for at least five years. During the five year rate moratorium, SLNG's ability to file a general rate increase and the ability of consenting parties to advocate a rate decrease is limited.

*Other Matter*

*Duke Litigation.* CTC, a direct subsidiary of Citrus, has filed suit against Duke Energy LNG Sales, Inc (Duke) and PanEnergy Corp., the holding company of Duke, seeking damages of $185 million for breach of a gas supply contract and wrongful termination of that contract. Duke sent CTC notice of termination of the gas supply contract alleging failure of CTC to increase the amount of an outstanding letter of credit as collateral for its purchase obligations. CTC filed a motion for partial summary judgement, requesting that the court find that Duke failed to give proper notice of default to CTC regarding its alleged failure to maintain the letter of credit. Duke has filed an amended counter claim in federal court joining Citrus and a cross motion for partial summary judgment, requesting that the court find that Duke had a right to terminate its gas sales contract with CTC due to the failure of CTC to adjust the amount of the letter of credit supporting its purchase obligations. CTC filed an answer to Duke's motion. In August 2005, the federal district court issued an order denying both motions for summary judgment, asserting that the ambiguity in the contract and the performance of the parties created issues of fact that precluded summary judgment for either side. CTC has filed additional motions for partial summary judgment, requesting that the court find that Duke improperly asserted force majeure due to its alleged loss of gas supply and that Duke is in error in asserting that CTC breached contractual provisions that imposed resale restrictions and credit maintenance obligations. An unfavorable outcome on this matter could impact the value of our investment in Citrus, which in turn, could have an effect on us.

*Capital Commitments and Purchase Obligations*

At December 31, 2005, we had capital and investment commitments of $27 million related to the expansions of our Elba Island facility and our Cypress project. Our other planned capital and investment projects are discretionary in nature, with no substantial contractual capital commitments made in advance of the actual expenditures. In addition, we have entered into unconditional purchase obligations for products and services totaling $15 million at December 31, 2005. Our annual obligations under these agreements are $11 million for 2006 and $1 million for each of the years from 2007 through 2010.

*Operating Leases*

We lease property, facilities and equipment under various operating leases. The majority of our total commitments on operating leases is the lease of the AmSouth Center located in Birmingham, Alabama. El Paso guarantees our obligations under this lease agreement. Minimum future annual rental commitments on our operating leases as of December 31, 2005, were as follows:

| Year Ending December 31, | Operating Leases |
|---|---|
| | (In millions) |
| 2006 | $ 3 |
| 2007 | 3 |
| 2008 | 3 |
| 2009 | 1 |
| 2010 | 1 |
| Total | $11 |

Rental expense on our operating leases for each of the years ended December 31, 2005, 2004 and 2003 was $3 million. These amounts include our share of rent allocated to us from El Paso.

## 8. Retirement Benefits

*Pension and Retirement Benefits*

El Paso maintains a pension plan to provide benefits determined under a cash balance formula covering substantially all of its U.S. employees, including our employees. Prior to January 1, 2000, Sonat Inc. (Sonat), our former parent company, maintained a pension plan for our employees. On January 1, 2000, the Sonat pension plan was merged into El Paso's cash balance plan. El Paso also maintains a defined contribution plan covering its U.S. employees, including our employees. El Paso matches 75 percent of participant basic contributions up to 6 percent of eligible compensation and can make additional discretionary matching contributions. El Paso is responsible for benefits accrued under its plans and allocates the related costs to its affiliates.

*Postretirement Benefits*

We provide medical benefits for a closed group of retirees. These benefits may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs. El Paso reserves the right to change these benefits. Employees who retire after June 30, 2000, continue to receive limited postretirement life insurance benefits. Our postretirement benefit plan costs are prefunded to the extent these costs are recoverable through our rates. We expect to contribute $3 million to our postretirement benefit plan in 2006.

In 2004, we adopted FASB Staff Position (FSP) No. 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.* This pronouncement required us to record the impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 on our postretirement benefit plans that provide drug benefits covered by that legislation. The adoption of FSP No. 106-2 decreased our accumulated postretirement benefit obligation by $17 million, which is deferred as an actuarial gain in our postretirement benefit liabilities. We also reduced our postretirement benefit expense by approximately $2 million in 2005.

The following table presents the change in projected benefit obligation, change in plan assets and reconciliation of funded status for our postretirement benefit plan. Our benefits are presented and computed as of and for the twelve months ended September 30 (the plan reporting date):

| | 2005 | 2004 |
|---|---|---|
| | (In millions) | |
| Change in benefit obligation: | | |
| Projected benefit obligation at beginning of period | $ 89 | $108 |
| Interest cost | 5 | 6 |
| Participant contributions | 1 | 1 |
| Actuarial gain | (4) | (21) |
| Benefits paid | (6) | (5) |
| Projected benefit obligation at end of period | $ 85 | $ 89 |
| Change in plan assets: | | |
| Fair value of plan assets at beginning of period | $ 53 | $ 51 |
| Actual return on plan assets | 4 | 2 |
| Employer contributions | 4 | 4 |
| Participant contributions | 1 | 1 |
| Benefits paid | (6) | (5) |
| Fair value of plan assets at end of period | $ 56 | $ 53 |
| Reconciliation of funded status: | | |
| Under funded status as of September 30 | $(29) | $(36) |
| Unrecognized actuarial loss | 6 | 12 |
| Net accrued benefit cost at December 31[1] | $(23) | $(24) |

[1] Based on our current funded status, we have reflected approximately $3 million of our accrued benefit obligation as a current liability at December 31, 2005.

Future benefits expected to be paid on our postretirement plan as of December 31, 2005, are as follows (in millions):

| Year Ending December 31, | |
|---|---|
| 2006 | $ 6 |
| 2007 | 6 |
| 2008 | 6 |
| 2009 | 6 |
| 2010 | 7 |
| 2011 – 2015 | 29 |
| Total | $60 |

Our postretirement benefit costs recorded in operating expenses include the following components for the years ended December 31:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| | | (In millions) | |
| Interest cost | $ 5 | $ 6 | $ 5 |
| Expected return on plan assets | (3) | (3) | (2) |
| Amortization of actuarial loss | — | 2 | — |
| Net postretirement benefit cost | $ 2 | $ 5 | $ 3 |

Projected benefit obligations and net benefit costs are based on actuarial estimates and assumptions. The following table details the weighted average actuarial assumptions used for our postretirement plan for 2005, 2004 and 2003:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| | | (Percent) | |
| Assumptions related to benefit obligations at September 30: | | | |
| Discount rate | 5.25 | 5.75 | |
| Assumptions related to benefit costs at December 31: | | | |
| Discount rate | 5.75 | 6.00 | 6.75 |
| Expected return on plan assets[1] | 7.50 | 7.50 | 7.50 |

[1] The expected return on plan assets is a pre-tax rate (before a tax rate ranging from 29 percent to 31 percent on postretirement benefits) that is primarily based on an expected risk-free investment return, adjusted for historical risk premiums and specific risk adjustments associated with our debt and equity securities. These expected returns were then weighted based on the target asset allocations of our investment portfolio.

Actuarial estimates for our postretirement benefits plan assumed a weighted average annual rate of increase in the per capita costs of covered health care benefits of 10.9 percent, gradually decreasing to 5.0 percent by the year 2015. Assumed health care cost trends can have a significant effect on the amounts reported for our postretirement benefit plan. A one-percentage point change in our assumed health care cost trends would have the following effects as of September 30:

| | 2005 | 2004 |
|---|---|---|
| | (In millions) | |
| One percentage point increase: | | |
| Aggregate of service cost and interest cost | $— | $— |
| Accumulated postretirement benefit obligation | $ 8 | $ 7 |
| One percentage point decrease: | | |
| Aggregate of service cost and interest cost | $— | $— |
| Accumulated postretirement benefit obligation | $(6) | $(6) |

*Postretirement Plan Assets*

The following table provides the actual asset allocations in our postretirement plan as of September 30:

| Asset Category | Actual 2005 | Actual 2004 |
|---|---|---|
| | (Percent) | |
| Equity securities | 60 | 62 |
| Debt securities | 31 | 34 |
| Other | 9 | 4 |
| Total | 100 | 100 |

The primary investment objective of our plan is to ensure that, over the long-term life of the plan, an adequate pool of sufficiently liquid assets exists to support the benefit obligation to participants, retirees and beneficiaries. In meeting this objective, the plan seeks to achieve a high level of investment return consistent with a prudent level of portfolio risk. Investment objectives are long-term in nature covering typical market cycles of three to five years. Any shortfall in investment performance compared to investment objectives is the result of general economic and capital market conditions.

The target allocation for the invested assets is 65 percent equity and 35 percent fixed income. Other assets are held in cash for payment of benefits upon presentment. Any El Paso stock held by the plan is held indirectly through investments in mutual funds.

### 9. Transactions with Major Customers

The following table shows revenues from our major customers for each of the three years ended December 31:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| | | (In millions) | |
| Scana Corporation[1] | $62 | $64 | $62 |
| Southern Company Services[2] | 55 | 48 | 34 |

(1) A significant portion of revenues received from a subsidiary of Scana Corporation resulted from firm capacity released by Atlanta Gas Light Company under terms allowed by our tariff.

(2) In 2004 and 2003, Southern Company Services did not represent more than 10 percent of our revenues.

### 10. Supplemental Cash Flow Information

The following table contains supplemental cash flow information for each of the three years ended December 31:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| | | (In millions) | |
| Interest paid, net of capitalized interest | $93 | $94 | $75 |
| Income tax payments | 49 | 48 | 25 |

### 11. Investments in Unconsolidated Affiliates and Transactions with Affiliates

*Investments in Unconsolidated Affiliates*

Our investments in unconsolidated affiliates are accounted for using the equity method of accounting and consist of our ownership interests in Citrus and Bear Creek.

*Citrus.* We have a 50 percent ownership interest in Citrus. Citrus owns and operates the FGT pipeline system, a 4,867 mile regulated pipeline system that extends from producing regions in Texas to markets in Florida. CrossCountry owns the other 50 percent of Citrus. The ownership agreements of Citrus provide each partner with a right of first refusal to purchase the ownership interest of the other partner. Our investment in Citrus is limited to our ownership of the voting stock of Citrus, and we have no financial obligations, commitments or guarantees, either written or oral, to support Citrus.

During 2005 and 2004, we received $61 million and $70 million in dividends from Citrus. At December 31, 2005 and 2004, our investment in Citrus was $596 million and $589 million.

*Bear Creek.* We have a 50 percent ownership interest in Bear Creek, a joint venture with TSC, our affiliate. Bear Creek owns and operates an underground natural gas storage facility located in Louisiana. The facility has a capacity of 50 Bcf of base gas and 58 Bcf of working storage. Bear Creek's working storage capacity is committed equally to the TGP and our pipeline system under long-term contracts. Our investment in Bear Creek at December 31, 2005 and 2004, was $101 million and $151 million. During 2005, we received $64 million in dividends from Bear Creek.

Summarized financial information of our proportionate share of our unconsolidated affiliates as of and for the years ended December 31 are as follows:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| | | (In millions) | |
| Operating results data: | | | |
| Operating revenues | $256 | $249 | $241 |
| Operating expenses | 109 | 100 | 112 |
| Income from continuing operations and net income[1] | 76 | 74 | 50 |

| | 2005 | 2004 |
|---|---|---|
| | (In millions) | |
| Financial position data: | | |
| Current assets | $ 74 | $ 121 |
| Non-current assets | 1,573 | 1,603 |
| Short-term debt | 7 | 7 |
| Other current liabilities | 32 | 36 |
| Long-term debt | 461 | 506 |
| Other non-current liabilities | 402 | 384 |
| Equity in net assets[(1)] | 745 | 791 |

(1) The differences between our proportionate share of our equity investments' net income and our earnings from unconsolidated affiliates and our share of their net equity and our overall investment are due primarily to the excess purchase price amortization related to Citrus and differences between the estimated and actual equity earnings on our investments.

*Transactions with Affiliates*

*Cash Management Program.* We participate in El Paso's cash management program which matches short-term cash surpluses and needs of participating affiliates, thus minimizing total borrowings from outside sources. We have historically provided cash to El Paso in exchange for an affiliated note receivable that is due upon demand. However, at December 31, 2005 and 2004, we do not anticipate settlement within the next twelve months and therefore, classified this receivable as non-current on our balance sheet. At December 31, 2005 and 2004, we had a note receivable from El Paso of $272 million and $169 million. The interest rate at December 31, 2005 and 2004, was 5.0% and 2.0%.

*Taxes.* We are a party to a tax accrual policy with El Paso whereby El Paso files U.S. and certain state tax returns on our behalf. In certain states, we file and pay directly to the state taxing authorities. We had income taxes payable of $52 million and $46 million at December 31, 2005 and 2004, included in taxes payable on our balance sheets. The majority of these balances will become payable to El Paso. See Note 1 for a discussion of our tax accrual policy.

*Other Affiliate Balances.* At December 31, 2005 and 2004, we had contractual deposits with our affiliates arising in the ordinary course of business of $1 million. In addition, at December 31, 2005 and 2004, we had notes receivable from El Paso of $67 million and $2 million.

In 2004, we acquired assets from our affiliate with a net book value of $4 million.

In 2003, we declared and paid a $600 million dividend, $310 million of which was a non-cash distribution of affiliated receivables and $290 million of which was cash.

*Affiliate Revenues and Expenses.* We enter into transactions with other El Paso subsidiaries in the normal course of our business to transport, sell and purchase natural gas. Services provided to or by these affiliates are based on the same terms as non-affiliates.

El Paso bills us directly for certain general and administrative costs and allocates a portion of its general and administrative costs to us. This allocation is based on the estimated level of effort devoted to our operations and the relative size of our EBIT, gross property and payroll. In addition to allocations from El Paso, we are also allocated costs from TGP associated with our pipeline services. El Paso currently bills us directly for compensation expense related to certain stock-based compensation awards granted directly to our employees as well as allocates to us our proportionate share of El Paso's corporate compensation expense. On January 1, 2006, El Paso adopted SFAS No. 123(R), *Share-Based Payment,* which requires that companies measure all employee stock-based compensation awards at fair value on the date they are granted to employees and recognize compensation costs in its financial statements over the requisite service period. As a result, beginning in 2006, we will record additional expense for all stock-based compensation awards (including stock options) granted directly to our employees as well as our allocable share of El Paso's corporate stock-based compensation expense.

The following table shows revenues and charges from our affiliates for each of the three years ended December 31:

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| | | (In millions) | |
| Revenues from affiliates | $ 7 | $10 | $37 |
| Operation and maintenance expenses from affiliates | 56 | 48 | 48 |

**12. Supplemental Selected Quarterly Financial Information (Unaudited)**

Financial information by quarter is summarized below:

| | Quarters Ended | | | | |
|---|---|---|---|---|---|
| | March 31 | June 30 | September 30 | December 31 | Total |
| | | | (In millions) | | |
| 2005 | | | | | |
| Operating revenues | $125 | $112 | $116 | $124 | $477 |
| Operating income | 72 | 58 | 49 | 49 | 228 |
| Net income | 52 | 43 | 39 | 40 | 174 |
| 2004 | | | | | |
| Operating revenues | $128 | $118 | $121 | $160 | $527 |
| Operating income | 63 | 52 | 48 | 83 | 246 |
| Net income | 36 | 39 | 33 | 61 | 169 |

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholder of
Southern Natural Gas Company:

In our opinion, the accompanying consolidated financial statements listed in the Index appearing under Item 15(a)(1), present fairly, in all material respects, the consolidated financial position of Southern Natural Gas Company and its subsidiaries (the "Company") at December 31, 2005 and December 31, 2004, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the Index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements 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. An audit 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Birmingham, Alabama
March 15, 2006

## SCHEDULE II

## SOUTHERN NATURAL GAS COMPANY
## VALUATION AND QUALIFYING ACCOUNTS

### Years Ended December 31, 2005, 2004 and 2003
### (In millions)

| Description | Balance at Beginning of Period | Charged to Costs and Expenses | Deductions | Charged to Other Accounts | Balance at End of Period |
|---|---|---|---|---|---|
| 2005 | | | | | |
| Allowance for doubtful accounts | $ 3 | $— | $— | $(2) | $ 1 |
| Valuation allowance on deferred tax assets | 1 | — | — | — | 1 |
| Legal reserves | 2 | — | — | — | 2 |
| 2004 | | | | | |
| Allowance for doubtful accounts | $ 3 | $— | $— | $— | $ 3 |
| Valuation allowance on deferred tax assets | 1 | — | — | — | 1 |
| Legal reserves | 1 | — | — | 1 | 2 |
| Environmental reserves | 3 | 1 | (4)[1] | — | — |
| 2003 | | | | | |
| Allowance for doubtful accounts | $ 3 | $— | $— | $— | $ 3 |
| Valuation allowance on deferred tax assets | 1 | — | — | — | 1 |
| Legal reserves | — | — | — | 1 | 1 |
| Environmental reserves | 4 | 3 | (4)[1] | — | 3 |

(1) Primarily payments made for environmental remediation activities.

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

None.

## ITEM 9A. CONTROLS AND PROCEDURES

### Evaluation of Disclosure Controls and Procedures

As of December 31, 2005, we carried out an evaluation under the supervision and with the participation of our management, including our President and Chief Financial Officer, as to the effectiveness, design and operation of our disclosure controls and procedures, as defined by the Securities Exchange Act of 1934, as amended. This evaluation considered the various processes carried out under the direction of our disclosure committee in an effort to ensure that information required to be disclosed in the SEC reports we file or submit under the Exchange Act is accurate, complete and timely.

Based on the results of this evaluation, our President and Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2005.

### Changes in Internal Control Over Financial Reporting

There were no changes in our internal control over financial reporting that have materially affected or are reasonably likely to materially affect our internal control over financial reporting during the fourth quarter 2005.

## ITEM 9B. OTHER INFORMATION

None.

# PART III

Item 10, "Directors and Executive Officers of the Registrant;" Item 11, "Executive Compensation;" Item 12, "Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters;" and Item 13, "Certain Relationships and Related Transactions," have been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

## ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

### Audit Fees

The audit fees for the years ended December 31, 2005 and 2004 of $740,000 and $925,000 were for professional services rendered by PricewaterhouseCoopers LLP for the audits of the consolidated financial statements of Southern Natural Gas Company.

### All Other Fees

No other audit-related, tax or other services were provided by our independent registered public accounting firm for the years ended December 31, 2005 and 2004.

### Policy for Approval of Audit and Non-Audit Fees

We are a wholly owned subsidiary of El Paso and do not have a separate audit committee. El Paso's Audit Committee has adopted a pre-approval policy for audit and non-audit services. For a description of El Paso's pre-approval policies for audit and non-audit related services, see El Paso Corporation's proxy statement for its 2006 Annual Meeting of Stockholders.

## PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

**(a) The following documents are filed as a part of this report:**

1. Financial statements.

The following consolidated financial statements are included in Part II, Item 8 of this report:



The following financial statements of our equity investment are included on the following pages of this report:



2. Financial statement schedules.



All other schedules are omitted because they are not applicable, or the required information is disclosed in the financial statements or accompanying notes.

**Citrus Corp. and Subsidiaries**
**Consolidated Financial Statements**
***Years ended December 31, 2005, 2004 and 2003***
***with Report of Independent Registered Public Accounting Firm***

## TABLE OF CONTENTS

## Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Citrus Corp. and Subsidiaries:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, of stockholders' equity, of comprehensive income and of cash flows present fairly, in all material respects, the financial position of Citrus Corp. and subsidiaries (the "Company") at December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 in conformity with the accounting principles generally accepted in the United States of America. These consolidated 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 of these statements 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. An audit 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, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

PricewaterhouseCoopers LLP

Houston, Texas
March 3, 2006

## CITRUS CORP. AND SUBSIDIARIES

## CONSOLIDATED BALANCE SHEETS

**(In Thousands)**

| | December 31, 2005 | December 31, 2004 |
|---|---|---|
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 21,406 | $ 11,645 |
| Accounts receivable — customers, net of allowance for doubtful accounts of $23 and $33 | 41,072 | 41,475 |
| Income tax receivable | 872 | — |
| Materials and supplies | 3,077 | 3,113 |
| Exchange gas receivable | 508 | 1,273 |
| Other | 1,184 | 1,609 |
| Total Current Assets | 68,119 | 59,115 |
| **Property, Plant and Equipment, at Cost** | | |
| Plant in service | 4,118,518 | 4,085,138 |
| Construction work in progress | 9,693 | 12,202 |
| Less — accumulated depreciation and amortization | (1,211,663) | (1,130,593) |
| Property, Plant and Equipment, Net | 2,916,548 | 2,966,747 |
| **Other Assets** | | |
| Unamortized debt expense | 5,735 | 6,788 |
| Regulatory assets | 24,092 | 22,840 |
| Other | 74,893 | 86,446 |
| Total Other Assets | 104,720 | 116,074 |
| **Total Assets** | $ 3,089,387 | $ 3,141,936 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Long-term debt due within one year | $ 14,000 | $ 14,000 |
| Accounts payable — trade and other | 21,325 | 19,753 |
| Accounts payable — affiliated companies | 5,501 | 13,471 |
| Accrued interest | 15,091 | 15,415 |
| Accrued income taxes | — | 6,332 |
| Accrued taxes, other than income | 9,090 | 8,792 |
| Exchange gas payable | 5,182 | 6,539 |
| Other | 6,161 | 3,094 |
| Total Current Liabilities | 76,350 | 87,396 |
| **Deferred Credits** | | |
| Deferred income taxes | 758,775 | 746,035 |
| Regulatory liabilities | 9,049 | 5,303 |
| Other | 33,070 | 7,971 |
| Total Deferred Credits | 800,894 | 759,309 |
| **Long-Term Debt** | 922,355 | 1,010,825 |
| **Stockholders' Equity** | | |
| Common stock, $1 par value; 1,000 shares authorized, issued and outstanding | 1 | 1 |
| Additional paid-in capital | 634,271 | 634,271 |
| Accumulated other comprehensive loss | (13,162) | (15,800) |
| Retained earnings | 668,678 | 665,934 |
| Total Stockholders' Equity | 1,289,788 | 1,284,406 |
| **Total Liabilities and Stockholders' Equity** | $ 3,089,387 | $ 3,141,936 |

See accompanying notes

## CITRUS CORP. AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF INCOME

**(In Thousands)**

| | Year Ended December 31, 2005 | Year Ended December 31, 2004 | Year Ended December 31, 2003 |
|---|---|---|---|
| **Revenues** | | | |
| Transportation of natural gas | $ 476,049 | $ 467,422 | $ 442,010 |
| Gas sales | — | 44,996 | 104,370 |
| Total Revenues | 476,049 | 512,418 | 546,380 |
| **Costs and Expenses** | | | |
| Natural gas purchased | — | 48,921 | 99,130 |
| Operations and maintenance | 78,829 | 81,306 | 117,086 |
| Depreciation and amortization | 91,125 | 68,053 | 64,522 |
| Taxes, other than income taxes | 34,306 | 29,565 | 27,436 |
| Total Costs and Expenses | 204,260 | 227,845 | 308,174 |
| **Operating Income** | 271,789 | 284,573 | 238,206 |
| **Other Income (Expense)** | | | |
| Interest expense and related charges, net | (79,290) | (93,771) | (103,109) |
| Other, net | 6,531 | 15,262 | (10,327) |
| Total Other Income (Expense) | (72,759) | (78,509) | (113,436) |
| **Income Before Income Taxes** | 199,030 | 206,064 | 124,770 |
| **Income Tax Expense** | 75,086 | 79,220 | 48,554 |
| **Net Income** | $ 123,944 | $ 126,844 | $ 76,216 |

See accompanying notes

## CITRUS CORP. AND SUBSIDIARIES

## CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

**(In Thousands)**

| | Year Ended December 31, 2005 | Year Ended December 31, 2004 | Year Ended December 31, 2003 |
|---|---|---|---|
| **Common Stock** | | | |
| Balance, beginning and end of period | $ 1 | $ 1 | $ 1 |
| **Additional Paid-in Capital** | | | |
| Balance, beginning and end of period | 634,271 | 634,271 | 634,271 |
| **Accumulated Other Comprehensive Income (Loss):** | | | |
| Balance, beginning of period | (15,800) | (17,247) | (18,453) |
| Recognition in earnings of previously deferred net losses related to derivative instruments used as cash flow hedges | 2,638 | 1,447 | 1,206 |
| Balance, end of period | (13,162) | (15,800) | (17,247) |
| **Retained Earnings** | | | |
| Balance, beginning of period | 665,934 | 679,090 | 602,874 |
| Net income | 123,944 | 126,844 | 76,216 |
| Dividends | (121,200) | (140,000) | — |
| Balance, end of period | 668,678 | 665,934 | 679,090 |
| **Total Stockholders' Equity** | $ 1,289,788 | $ 1,284,406 | $ 1,296,115 |

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

**(In Thousands)**

| | Year Ended December 31, 2005 | Year Ended December 31, 2004 | Year Ended December 31, 2003 |
|---|---|---|---|
| Net income | $ 123,944 | $ 126,844 | $ 76,216 |
| Recognition in earnings of previously deferred net losses related to derivative instruments used as cash flow hedges | 2,638 | 1,447 | 1,206 |
| **Total Comprehensive Income** | $ 126,582 | $ 128,291 | $ 77,422 |

See accompanying notes

## CITRUS CORP. AND SUBSIDIARIES
## CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Year Ended December 31, 2005 | Year Ended December 31, 2004 | Year Ended December 31, 2003 |
|---|---|---|---|
| **Cash Flows From Operating Activities** | | | |
| Net income | $ 123,944 | $ 126,844 | $ 76,216 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation and amortization | 91,125 | 68,053 | 64,522 |
| Amortization of hedge loss in other comprehensive income | 2,638 | 1,447 | 1,206 |
| Amortization of discount and swap hedge loss in long term debt | 530 | 535 | 392 |
| Amortization of regulatory assets and other deferred charges | 3,380 | 5,205 | 12,000 |
| Amortization of debt costs | 1,053 | 922 | 1,840 |
| Deferred income taxes | 12,740 | 69,694 | 24,271 |
| Price risk management fair market valuation revaluation | — | 10,980 | 20,599 |
| Price risk management gain on buy out of gas sales contract | — | (19,884) | — |
| Allowance for funds used during construction | (1,441) | (1,136) | (5,804) |
| Gain on sale of assets | (1,236) | — | — |
| Changes in operating assets and liabilities: | | | |
| Accounts receivable | 403 | (1,762) | 9,443 |
| Materials and supplies | 36 | (198) | 422 |
| Accounts payable | (10,567) | (17,258) | (7,029) |
| Accrued interest | (324) | (3,639) | (2,291) |
| Accrued income tax | (7,204) | 5,183 | 4,796 |
| Accrued other tax | 298 | (1,556) | 1,241 |
| Other current assets and liabilities | 2,900 | (7,926) | 9,863 |
| Price risk management assets and liabilities | — | (23,162) | 7,150 |
| Other assets and liabilities | 36,140 | 2,169 | 14,561 |
| **Net Cash Provided by Operating Activities** | 254,415 | 214,511 | 233,398 |
| **Cash Flows From Investing Activities** | | | |
| Additions to property, plant and equipment | (37,306) | (47,694) | (142,334) |
| Allowance for funds used during construction | 1,441 | 1,136 | 5,804 |
| Retirements and disposition of property, plant and equipment, net | (304) | (1,288) | (1,074) |
| Proceeds from sale of assets | 1,715 | — | — |
| **Net Cash Used in Investing Activities** | (34,454) | (47,846) | (137,604) |
| **Cash Flows From Financing Activities** | | | |
| Dividends | (121,200) | (140,000) | — |
| Borrowings under the revolving credit facility | 223,000 | 155,000 | — |
| Payments on the revolving credit facility | (298,000) | (38,000) | — |
| Long-term debt finance costs | — | (746) | — |
| Payments on long-term debt | (14,000) | (256,500) | (85,250) |
| **Net Cash Used in Financing Activities** | (210,200) | (280,246) | (85,250) |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | 9,761 | (113,581) | 10,544 |
| **Cash and Cash Equivalents, Beginning of Period** | 11,645 | 125,226 | 114,682 |
| **Cash and Cash Equivalents, End of Period** | $ 21,406 | $ 11,645 | $ 125,226 |
| **Supplemental Disclosure of Cash Flow Information** | | | |
| Interest paid (net of amounts capitalized) | $ 74,714 | $ 95,770 | $ 105,641 |
| Income tax paid | $ 67,018 | $ 4,432 | $ 19,488 |

See accompanying notes

## CITRUS CORP. AND SUBSIDIARIES
## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### (1) Reporting Entity

Citrus Corp. (Citrus), a holding company formed in 1986, owns 100 percent of the stock of Florida Gas Transmission Company (FGT), Citrus Trading Corp. (Trading) and Citrus Energy Services, Inc. (CESI), collectively the Company. At December 31, 2005 the stock of Citrus was owned 50 percent by El Paso Citrus Holdings, Inc. (EPCH), a wholly owned subsidiary of Southern Natural Gas Company (Southern), as transferred by Southern in December 2003, and 50 percent by CrossCountry Citrus, LLC (CCC), a wholly owned subsidiary of CrossCountry Energy, LLC (CrossCountry). Southern's 50 percent ownership had previously been contributed by its parent, El Paso Corporation (El Paso) in March 2003. CrossCountry was a wholly owned subsidiary of Enron Corp. (Enron) and certain of its subsidiary companies. Effective November 17, 2004 CrossCountry became a wholly owned subsidiary of CCE Holdings, LLC (CCE Holdings), which is a joint venture owned by subsidiaries of Southern Union Company (Southern Union) (50 percent), GE Commercial Finance Energy Financial Services (GE) (approximately 30 percent) and four minority interest owners (approximately 20 percent in the aggregate).

FGT, an interstate gas pipeline extending from South Texas to South Florida, is engaged in the interstate transmission of natural gas and is subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Trading ceased all trading activities effective the fourth quarter of 1997, but continued to fulfill its obligations under the remaining gas purchase and gas sale contracts through the last quarter of 2004. During 2004, it sold its remaining contracts and no longer has any gas purchase or gas sale contracts.

CESI primarily provides transportation management and financial services to customers of FGT. CESI terminated its Operations and Maintenance (O&M) business in 2003, due to increased insurance costs and pipeline integrity legislation that affects operators.

### (2) Significant Accounting Policies

**Principles of Consolidation** – The consolidated financial statements include the accounts of Citrus and its wholly owned subsidiaries. All significant inter company transactions and accounts have been eliminated in consolidation.

**Reclassifications** – Certain reclassifications have been made to the consolidated financial statements for prior years to conform to the current year presentation with no impact on reported net income, stockholders' equity or net cash provided by, or used in, operating, investing or financing activities.

**Regulatory Accounting** – FGT's accounting policies generally conform to Statement of Financial Accounting Standards (SFAS) No. 71, *Accounting for the Effects of Certain Types of Regulation.* Accordingly, certain assets and liabilities that result from the regulated ratemaking process are recorded that would not be recorded under accounting principles generally accepted in the United States for non-regulated entities. FGT is subject to regulation by the FERC.

**Revenue Recognition** – Revenues consist primarily of fees earned from gas transportation services. Reservation revenues on firm contracted capacity are recognized ratably over the contract period. For interruptible or volumetric based services, commodity revenues are recorded upon the delivery of natural gas to the agreed upon delivery point. Revenues for all services are generally based on the thermal quantity of gas delivered or subscribed at a rate specified in the contract.

Because FGT is subject to FERC regulations, revenues collected during the pendency of a rate proceeding may be required by the FERC to be refunded in the final order. FGT establishes reserves for such potential refunds, as appropriate, which were $0.0 and $0.3 million at December 31, 2005 and 2004, respectively.

**Accounting for Derivative Instruments** – The Company was previously engaged in price risk management activities for both trading and non-trading activities and accounted for those contracts under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* (see Note 4). Instruments utilized in connection with trading activities were accounted for on a mark-to-market basis and were reflected at fair value as Assets and Liabilities from Price Risk Management Activities in the Consolidated Balance Sheets. The Company classified price risk management activities as either current or non-current assets or liabilities based on their anticipated settlement date. Earnings from revaluation of price risk management assets and liabilities were included in Other Income (Expense). Cash flow hedge accounting is utilized for non-trading purposes to hedge the impact of interest rate fluctuations associated with the Company's debt. Unrealized gains and losses from cash flow hedges, to the extent such amounts are effective, are recognized as a component of other comprehensive income, and subsequently recognized in earnings in the same periods as the hedged forecasted transaction affects earnings. The ineffective component from cash flow hedges is recognized in Other Income (Expense) each period. In instances where the hedge no longer qualifies as being effective, hedge accounting is terminated prospectively and the accumulated gain or loss is recognized in earnings in the same periods during which the hedged forecasted transaction affects earnings. Where fair value hedge accounting is appropriate, the offset that is attributed to the risk being hedged is recorded as an adjustment to the hedged item in the statement of operations (see Note 4). In the Company's cash flow statement, cash inflows and outflows associated with the settlement of the price risk management activities are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported as trade receivables or payables on the balance sheet.

**Property, Plant and Equipment** (see Note 10) – Property, Plant and Equipment consists primarily of natural gas pipeline and related facilities. The Company amortized that portion of its investment in FGT and other subsidiaries which is in excess of historical cost (acquisition adjustment) on a straight-line basis at an annual composite rate of 1.6 percent. FGT has provided for depreciation of assets net of estimated salvage value, on a straight-line basis, at an annual composite rate of 2.56 percent, 1.74 percent and 1.66 percent for 2005, 2004 and 2003, respectively. The increase was due to higher depreciation reflecting the settlement of FGT's rate case effective April 1, 2005. The overall remaining useful life for FGT's assets at December 31, 2005 is 39 years.

Property, Plant and Equipment is recorded at its original cost. FGT capitalizes direct costs, such as labor and materials, and indirect costs, such as overhead, interest and an equity return component (see following paragraph). Costs of replacements and renewals of units of property are capitalized. The original costs of units of property retired are charged to the accumulated depreciation, net of salvage and removal costs. FGT charges to maintenance expense the costs of repairs and renewal of items determined to be less than units of property.

The recognition of an allowance for funds used during construction (AFUDC) is a utility accounting practice calculated under guidelines prescribed by the FERC and capitalized as part of the cost of utility plant. It represents the cost of servicing the capital invested in construction work-in-progress. AFUDC has been segregated into two component parts – borrowed funds and equity funds. The allowance for borrowed and equity funds used during construction totaled $1.4, $1.1 and $5.8 million in 2005, 2004 and 2003, respectively. AFUDC borrowed is included in Interest Expense and AFUDC equity is included in Other Income in the accompanying income statement.

The Company applies the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligation (ARO)* to record a liability for the estimated removal costs of assets where there is a legal obligation associated with removal. Under this standard, the liability is recorded at its fair value, with a corresponding asset that is depreciated over the remaining useful life of the long-lived asset to which the liability relates. An ongoing expense will also be recognized for changes in the value of the liability as a result of the passage of time. The Company adopted SFAS No. 143, beginning January 1, 2003.

FIN No. 47, "Accounting for Conditional Asset Retirement Obligations" issued by the FASB in March 2005 clarifies that the term "conditional asset retirement obligation" as used in FASB Statement No. 143, "Accounting for Asset Retirement Obligations", refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Accordingly, an entity is required to recognize a liability for the fair value of a conditional asset retirement obligation when incurred, if the fair value of the liability can be reasonably estimated. FIN No. 47 provides guidance for assessing whether sufficient information is available to record an estimate. This interpretation was effective for the Company beginning on December 31, 2005. Upon adoption of FIN No. 47, FGT recorded an increase in plant in service and a liability for an ARO of $0.5 million. This new asset and liability related to obligations associated with the removal and disposal of asbestos and asbestos containing materials on FGT's pipeline system.

The Company applies the provisions of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* to account for asset impairments. Under this standard, an asset is evaluated for impairment when events or circumstances indicate that a long-lived asset's carrying value may not be recovered. These events include market declines, changes in the manner in which an asset was intended to be used, decisions to sell an asset, and adverse changes in the legal or business environment such as adverse actions by regulators.

**Gas Imbalances** – Gas imbalances occur as a result of differences in volumes of gas received and delivered by a pipeline system. These imbalances due to or from shippers and operators are valued at an appropriate index price. Imbalances are settled in cash or made up in-kind subject to terms of FGT's tariff, and generally do not impact earnings.

**Environmental Expenditures** – Expenditures that relate to an existing condition caused by past operations, and do not contribute to current or future generation, are expensed. Environmental expenditures relating to current or future revenues are expensed or capitalized as appropriate based on the nature of the cost incurred. Liabilities are recorded when environmental assessments and/or clean ups are probable and the cost can be reasonably estimated (see Note 13).

**Cash and Cash Equivalents** – Cash equivalents consist of highly liquid investments with original maturities of three months or less. The carrying amount of cash and cash equivalents approximates fair value because of the short maturity of these investments.

**Materials and Supplies** – Materials and supplies are valued at the lower of cost or market value. Materials transferred out of warehouses are priced at average cost.

**Fuel Tracker** – A liability is recorded for net volumes of gas owed to customers collectively. Whenever fuel is due from customers from prior under recovery based on contractual and specific tariff provisions an asset is recorded. Gas owed to or from customers is valued at market. Changes in the balances have no effect on the consolidated income of the Company.

**Compressor Overhaul Expenditures** – In 2003 FGT changed its method of accounting for compressor overhaul costs by adopting a method for current expense recognition of compressor overhaul costs as part of operation and maintenance expenses. This change was the result of the Company's determination that such costs previously deferred would not be recovered through future tariff rates. In prior years, such costs were deferred and amortized ratably over the expected service life of the applicable overhaul item. An unamortized balance of $7.0 million applicable to the previous method was expensed in 2003. An additional amount of $6.5 million related to 2003 overhaul costs, which would have been deferred under the previous methodology, was also expensed. In 2004 the remaining unamortized overhaul costs of $0.5 million were expensed and an additional $4.8 million of overhaul costs related to 2004 overhauls were also expensed under the new methodology. In 2005 compressor overhaul expenses amounted to $4.7 million.

**Income Taxes** (see Note 5) – The Company accounts for income taxes under the provisions of SFAS No. 109, *Accounting for Income Taxes.* SFAS No. 109 provides for an asset and liability approach to accounting for income taxes. Under this approach, deferred tax assets and liabilities are recognized based on anticipated future tax consequences attributable to differences between financial statement carrying amounts of assets and liabilities and their respective tax bases.

**Trade Receivables** – The Company establishes an allowance for doubtful accounts on trade receivables based on the expected ultimate recovery of these receivables. The Company considers many factors including historical customer collection experience, general and specific economic trends and known specific issues related to individual customers, sectors and transactions that might impact collectibility. Unrecovered trade accounts receivable charged against the allowance for doubtful accounts were $0.0, $0.0 and $0.3 million in 2005, 2004 and 2003, respectively.

**Use of Estimates** – The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

**Recent Accounting Pronouncements**

FIN No. 46R-5, "Implicit Variable Interests under FASB Interpretation No. 46 (revised December 2003), Consolidation of Variable Interest Entities" issued by FASB in March 2005 addresses whether a reporting enterprise should consider whether it holds an implicit variable interest in a variable interest entity (VIE) or a potential VIE when specific conditions exist. An implicit variable interest is an implied pecuniary interest in an entity that indirectly changes with changes in the fair value of the entity's net assets exclusive of variable interests. Implicit variable interests may arise from transactions with related parties, as well as from transactions with unrelated parties. It will be effective, for entities to which the interpretations of FIN 46(R) have been applied, beginning December 31, 2005. As of March 31, 2005 the Company adopted this FSP, which had no impact on its consolidated financial statements.

FSP No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvements and Modernization Act of 2003" (the Medicare Prescription Drug Act) issued by the FASB in May 2004 requires entities to record the impact of the Medicare Prescription drug Act as an actuarial gain in the post-retirement benefit obligation for post-retirement benefit plans that provide drug benefits covered by the legislation. The Company adopted this FSP as of March 31, 2005 and recognized an actuarial gain of $0.2 million during the year ended December 31, 2005. The effect of this FSP may vary as a result of any future changes to the Company's benefit plans (see Note 6).

**(3) Long-Term Debt and Other Financing Arrangements**

Long-term debt outstanding at December 31, 2005 and 2004 was as follows (in thousands):

| | 2005 | 2004 |
|---|---|---|
| Citrus | | |
| 8.490% Notes due 2007-2009 | $ 90,000 | $ 90,000 |
| | 90,000 | 90,000 |
| FGT | | |
| 9.750% Notes due 1999-2008 | 19,500 | 26,000 |
| 10.110% Notes due 2009-2013 | 70,000 | 70,000 |
| 9.190% Notes due 2005-2024 | 142,500 | 150,000 |
| 7.625% Notes due 2010 | 325,000 | 325,000 |
| 7.000% Notes due 2012 | 250,000 | 250,000 |
| Revolving Credit Agreement due 2007 | 42,000 | 117,000 |
| Unamortized Debt Discount and Swap Loss | (2,645) | (3,175) |
| | 846,355 | 934,825 |
| Total Outstanding | 936,355 | 1,024,825 |
| Long-Term Debt Due Within One Year | (14,000) | (14,000) |
| | $ 922,355 | $ 1,010,825 |

Annual maturities of long-term debt outstanding as of December 31, 2005 were as follows (in thousands):

| Year | |
|---|---|
| 2006 | $ 14,000 |
| 2007 | 86,000 |
| 2008 | 44,000 |
| 2009 | 51,500 |
| 2010 | 346,500 |
| Thereafter | 397,000 |
| | $ 939,000 |

On August 13, 2004 FGT entered into a Revolving Credit Agreement ("2004 Revolver") with an initial commitment level of $50.0 million and terminating in August 2007. Effective November 15, 2004 the commitment level was increased by $125.0 million to $175.0 million. Since that time, FGT has routinely utilized the 2004 Revolver to fund working capital needs. On December 31, 2005 and 2004 the amounts drawn under the 2004 Revolver were $42.0 million and $117.0 million, respectively, with a weighted average interest rate of 5.11 percent (based on LIBOR plus 0.70 percent) and 3.24 percent (based on LIBOR plus 0.80 percent), respectively. Additionally, a commitment fee of 0.15 percent is payable quarterly on the unused commitment balance. The debt issuance costs accumulated for the 2004 Revolver at December 31, 2005 and 2004 were $0.4 million and $0.7 million, respectively.

FGT may incur additional debt to refinance maturing obligations if the refinancing does not increase aggregate indebtedness, and thereafter, if FGT and the Company's consolidated debt does not exceed specific debt to total capitalization ratios, as defined. Incurrence of additional indebtedness to refinance the current maturities would not result in a debt to capitalization ratio exceeding these limits.

Citrus has note agreements that contain certain restrictions that, among other things, limit the incurrence of additional debt, the sale of assets, and the payment of dividends, and require maintaining certain restrictive financial covenants, including required ratios of consolidated funded debt to consolidated capitalization, consolidated funded debt to consolidated net tangible assets, and consolidated cash flow to consolidated fixed charges. The agreements relating to FGT's promissory notes include, among other things, restrictions as to the payment of dividends and maintaining certain restrictive financial covenants, including a required ratio of consolidated funded debt to total capitalization. As of December 31, 2005 and 2004 the Company believes it was in compliance with both affirmative and restrictive covenants of the note agreements.

All of the debt obligations of Citrus and FGT have events of default that contain commonly used cross-default provisions. An event of default by either Citrus or FGT on any of their borrowed money obligations, in excess of certain thresholds which is not cured within defined grace periods, would cause the other debt obligations of FGT and Citrus to be accelerated.

## (4) Derivative Instruments

The Company determined that its gas purchase contracts for resale and related gas sales contracts were derivative instruments and recorded these at fair value as price risk management assets and liabilities under SFAS No. 133, as amended. The valuation was calculated using a discount rate adjusted for the Company's borrowing premium of 250 basis points, which created an implied reserve for credit and other related risks. The Company estimated the fair value of all derivative instruments based on quoted market prices, current market conditions, estimates obtained from third-party brokers or dealers, or amounts derived using internal valuation models. The Company performed a quarterly revaluation on the carrying balances that were reflected in current earnings. The impact to earnings from revaluation, mostly due to price fluctuations, was a loss of $11.0 and $20.6 million for 2004 and 2003, respectively. During the fourth quarter of 2004 the Company sold its remaining derivative contract without a material impact on the consolidated statements of income.

Prior to the Enron bankruptcy, Enron North America Corp. (ENA) was the principal counterparty to Trading's gas purchase and sale agreements (including swaps). ENA has rejected these contracts in bankruptcy. A pre-petition gas purchase payable to ENA of $12.4 million was reversed in 2003 when it was determined that the Company had a right of offset against claims for pre-petition receivables. Pursuant to an existing operating agreement which was rejected by ENA in 2003 but under which an El Paso affiliate performed, an affiliate of El Paso was required to buy gas, purchased from a significant third party that exceeded the requirements of Trading's existing sales contracts. Under this third party contract, gas was purchased primarily at rates based upon an indexed oil price formula. This gas was then sold primarily at market rates. On April 16, 2003 the significant third party supplier terminated the supply contract. Trading then only purchased the requirements to fulfill existing sales contracts from third parties at market rates. As a result of these developments, the cash flow stream was dependent on variable pricing, whereas before Enron's bankruptcy, the cash flow stream was fixed (under certain swaps). In June 2004 the Company paid $16.2 million and recorded an accrual for a contingent payment of up to $6.5 million to terminate a gas sales contract with a third-party, resulting in a net gain totaling $19.9 million. The contingent payment will be paid to the third-party from any future proceeds resulting from the settlement of either the ENA bankruptcy claims or the Duke Energy LNG Sales, Inc. (Duke) litigation (see below).

Due to a dispute (see Note 14) during 2003 Duke purported to terminate and discontinued performance under a natural gas purchase and supply contract between it and Trading, which Trading subsequently terminated. As a result of this contract termination, during 2003 Trading discontinued the application of fair market value accounting for this contract, and wrote off the value of the related price risk management assets as a charge to Other Income (Expense) in the accompanying statement of income. Pursuant to the terms of the contract and also during 2003 Trading issued to Duke, the counterparty, a termination invoice for approximately $187.0 million. As a result of the ongoing litigation regarding this matter, the termination invoice amount was recognized, net of reserves (which includes certain other matters), as an offsetting gain to Other Income (Expense) and is recorded as a long term receivable (see Note 11) of $68.5 and $68.5 million at December 31, 2005 and 2004, respectively.

## (5) Income Taxes

The principal components of the Company's net deferred income tax liabilities at December 31, 2005 and 2004 are as follows (in thousands):

| | 2005 | 2004 |
|---|---|---|
| Deferred income tax assets | | |
| Alternative minimum tax credit | $ — | $ 9,577 |
| Regulatory and other reserves | 8,841 | 6,295 |
| Other | 176 | 120 |
| | 9,017 | 15,992 |
| Deferred income tax liabilities | | |
| Depreciation and amortization | 728,444 | 717,223 |
| Deferred charges and other assets | 27,972 | 27,295 |
| Regulatory costs | 4,901 | 13,264 |
| Other | 6,475 | 4,245 |
| | 767,792 | 762,027 |
| Net deferred income tax liabilities | $ 758,775 | $ 746,035 |

Total income tax expense for the years ended December 31, 2005, 2004 and 2003 is summarized as follows (in thousands):

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Current Tax Provision | | | |
| Federal | $ 53,526 | $ 7,561 | $ 19,215 |
| State | 8,820 | 1,965 | 5,068 |
| | 62,346 | 9,526 | 24,283 |
| Deferred Tax Provision | | | |
| Federal | 11,079 | 60,808 | 21,930 |
| State | 1,661 | 8,886 | 2,341 |
| | 12,740 | 69,694 | 24,271 |
| Total income tax expense | $ 75,086 | $ 79,220 | $ 48,554 |

The differences between taxes computed at the U.S. federal statutory rate of 35 percent and the Company's effective tax rate for the years ended December 31, 2005, 2004 and 2003 are as follows (in thousands):

| | 2005 | 2004 | 2003 |
|---|---|---|---|
| Statutory federal income tax provision | $ 69,661 | $ 72,122 | $ 43,670 |
| State income taxes, net of federal benefit | 6,813 | 7,053 | 4,816 |
| Other | (1,388) | 45 | 68 |
| Income tax expense | $ 75,086 | $ 79,220 | $ 48,554 |
| Effective Tax Rate | 37.7% | 38.4% | 38.9% |

The Company has an alternative minimum tax (AMT) credit which can be used to offset regular income taxes payable in future years. The AMT credit has an indefinite carry-forward period. For financial statement purposes, the Company has recognized the benefit of the AMT credit carry-forward as a reduction of deferred tax liabilities. The ATM credit was fully utilized in 2005.

The Company files a consolidated federal income tax return separate from its parents.

## (6) Employee Benefit Plans

During 2003 the employees of the Company were covered under Enron's employee benefit plans. The Company's participation in the Enron benefit plans terminated during November 2004.

Certain retirees of FGT were covered under a deferred compensation plan managed and funded by Enron subsidiaries, one previously sold and the other now in bankruptcy. This matter has been included as part of the claim filed by FGT against Enron and another affiliated bankrupt company. FGT and Enron agreed in principle to a settlement, resulting in an allowed claim by FGT of approximately $3.4 million against Enron for the deferred compensation plan. Documents were approved by the bankruptcy court in May 2005. As a result of this settlement FGT assumed a deferred compensation plan liability of $1.8 million, which was recorded in 2004. The balance at December 31, 2005 is $1.8 million and is reported in Other Current Liabilities ($0.4 million) and in Other Deferred Credits ($1.4 million) (see Note 12). The anticipated proceeds from Enron for the bankruptcy claim described above was $0.5 million. Such amount was recorded as a long term receivable at December 31, 2004. In 2005 FGT assigned its claim to a third party and in June 2005 a payment of $0.8 million was received and recorded against the receivable. The excess $0.3 million was recorded as Other Income (see Note 8).

Enron maintained a pension plan that was a noncontributory defined benefit plan, the Enron Corp. Cash Balance Plan (the Cash Balance Plan), covering certain Enron employees in the United States and certain employees in foreign countries. The basic benefit accrual was 5 percent of eligible annual base pay. Pension expense charged to the Company by Enron was $0.3 and $1.9 million for 2004 and 2003, respectively. This excludes the Cash Balance termination amount discussed below.

In 2003 the Company recognized its portion of the expected Cash Balance Plan settlement by recording a $9.6 million current liability, which was cash settled in 2005 (see Note 8), and a charge to operating expense. In 2004, with the settlement of the rate case (see Note 9), FGT recognized a regulatory asset for its portion, $9.3 million, with a reduction to operating expense. Per the rate case settlement FGT will amortize, over five years retroactive to April 1, 2004, its allocated share of costs to fully fund and terminate the Cash Balance Plan. Amortization recorded was $1.9 million and $1.4 million for 2005 and 2004, respectively. At December 31, 2005 and 2004 FGT has a remaining regulatory asset balance for this matter of $6.0 million and $7.9 million, respectively. Based on the current status of the Cash Balance Plan termination cost and the amount expected to be allocated to the Company as its proportionate share of the plan's termination liability, the Company continues to believe its accruals related to this matter are adequate. Although there can be no assurance that amounts ultimately allocated to and paid by the Company will not be materially different, we do not believe that the ultimate resolution of these matters will have a materially adverse effect on the Company's consolidated financial position or cash flows, but it could have significant impact on the results of operations in future periods.

Effective November 1, 2004 the employees of the Company were transferred to an affiliated entity, CrossCountry Energy Services, LLC (CCES) and during November 2004, employee insurance coverage migrated (without lapse) from Enron plans to new CCES welfare and benefit plans. Effective March 1, 2005 essentially all such employees were transferred to FGT and became eligible at that time to participate in employee welfare and benefit plans adopted by FGT.

Effective March 1, 2005 FGT adopted the Florida Gas Transmission Company 401(k) Savings Plan (the Plan). All employees of FGT are eligible to participate and, under one Plan, may contribute up to 50 percent of pre-tax compensation, subject to IRS limitations. This Plan allows additional "catch-up" contributions by participants over age 50, and allows FGT to make discretionary profit sharing contributions for the benefit of all participants. FGT matches 50 percent of participant contributions under this Plan up to a maximum of 4% of eligible compensation. Participants vest in such matching and any profit sharing contributions at the rate of 20 percent per year, except that participants with five years of service at the date of adoption of the Plan were immediately vested. Administrative costs of the Plan and certain asset management fees are paid from Plan assets. FGT's expensed its contribution of $0.3 million for the year ended December 31, 2005.

**Other Post – Employment Benefits**

Enron provided certain post-retirement medical, life insurance and dental benefits (OPEB) to eligible employees and their eligible dependents through November 30, 2004. The net periodic post-retirement benefit costs charged to the Company by Enron were $0.6 and $1.2 million for 2004 and 2003, respectively. Substantially all of these amounts relate to FGT and are being recovered through rates. During the period December 1, 2004 through February 28, 2005 coverage to eligible employees and their eligible dependents was provided by CrossCountry Energy Retiree Health Plan, which provides only medical benefits. Effective March 1, 2005 such benefits are provided under an identical plan sponsored by FGT as a single employer post-retirement benefit plan.

FGT was previously a participating employer in the Enron Gas Pipelines Employee Benefit Trust (the Trust), a voluntary employees' beneficiary association (VEBA) under Section 501(c)(9) of the Internal Revenue Code of 1986, as amended (Tax Code),which provides benefits to employees of FGT and certain other Enron affiliates pursuant to the Enron Corp. Medical Plan and the Enron Corp. Medical Plan for Inactive Participants. Enron has made the determination that it will partition the Trust and distribute the assets and liabilities of the Trust among the participating employers of the Trust on a pro rata basis according to the contributions and liabilities associated with each participating employer. The Trust Committee has final approval on allocation methodology for the Trust assets. Enron filed a motion in the Enron bankruptcy proceedings on July 22, 2003 which was stayed and then refiled and amended on June 17, 2005 which provides that each participating employer expressly assumes liability for its allocable portion of retiree benefits and releases Enron from any liability with respect to the Trust in order to receive the assets of the Trust. On June 7, 2005 a class action suit captioned *Lou Geiler et al v. Robert W. Jones, et al.,* was filed in United States District Court for the District of Nebraska by, among others, former employees of Northern Natural Gas Company (Northern) on behalf of the participants in the Northern Medical and Dental Plan for Retirees and Surviving Spouses against former and present members of the Trust

Committee, the Trustee and the participating employers of the Trust, including FGT, claiming the Trust Committee and the Trustee have violated their fiduciary duties under ERISA and seeking a declaration from the Court binding on all participating employers of an accounting and distribution of the assets held in the Trust and a complete and accurate listing of the individuals properly allocated to Northern from the Enron Plan. On the same date essentially the same group filed a motion in the Enron bankruptcy proceedings to strike the Enron motion from further consideration. Both motions remain pending in the Enron bankruptcy court. On February 6, 2006 the Nebraska action was dismissed.

With regard to its sponsored plan, FGT has entered into a VEBA trust (the "VEBA Trust") agreement with Bank One Trust Company as a trustee. The VEBA Trust has established or adopted plans to provide certain post-retirement life, sick, accident and other benefits. The VEBA Trust is a voluntary employees' beneficiary association under Section 501(c)(9) of the Tax Code, which provides benefits to employees of the Company. FGT contributed $1.5 million to the VEBA Trust for the year ended December 31, 2005. Upon settlement of the Trust, any distribution of assets FGT receives from the Trust, estimated to be approximately $6.2 million per the Enron filing described above, will be contributed to the VEBA Trust.

Following its November 17, 2004 acquisition by CCEH, FGT continues to provide certain retiree benefits through employer contributions to a qualified contribution plan, with the amounts generally varying based on age and years of service.

Prior to 2005, FGT's general policy was to fund accrued post-retirement health care costs as allocated by Enron. As a result of FGT's change in 2005 from a participant in a multi employer plan to a single employer plan, FGT now accounts for its OPEB liability and expense on an actuarial basis, recording its health and life benefit costs over the active service period of employees to the date of full eligibility for the benefits.

The following table represents a reconciliation of FGT's OPEB plan at December 31, 2005:

| **OPEB** (in thousands) | **Year ended December 31, 2005** |
|---|---|
| Change in Benefit Obligation | |
| Benefit obligation at plan adoption(1) | $ 9,872 |
| Service cost | 71 |
| Interest cost | 490 |
| Actuarial gain | (3,522) |
| Retiree premiums | 757 |
| Benefits paid | (1,003) |
| Benefit obligation at end of year | $ 6,665 |
| Change in Plan Assets | |
| Fair value of plan assets at plan adoption(1) (2) | $ 6,240 |
| Return on plan assets | 352 |
| Employer contributions | 1,494 |
| Retiree premiums | 757 |
| Benefits paid | (1,003) |
| Fair value of plan assets at end of year | $ 7,840 |
| Funded Status | |
| Funded status at end of year | $ 1,175 |
| Unrecognized net actuarial gain | (3,348) |
| Net liability recognized at December 31, 2005 | $ (2,173) |

(1) For purposes of this reconciliation, the plan adoption date is considered to be January 1, 2005.

(2) Plan assets include the amount of assets expected to be received from the Enron Trust.

The weighted-average assumptions used to determine FGT's benefit obligations for the year ended December 31, 2005 were as follows:

| **As of December 31, 2005** | |
|---|---|
| Discount rate | 5.50% |
| Rate of compensation increase | N/A |
| Health care cost trend rates (graded to 4.65% by year 2012) | 12.00% |

FGT's OPEB benefit costs for the period presented consisted of the following:

| **OPEB** (in thousands) | **Year Ended December 31, 2005** |
|---|---|
| Service cost | $ 71 |
| Interest cost | 490 |
| Expected return on plan assets | (352) |
| Amortization of prior service cost | — |
| Recognized actuarial gain | (174) |
| Net periodic benefit cost | $ 35 |

The weighted-average assumptions used to determine FGT's OPEB benefit costs for the period presented were:

**Year Ended December 31, 2005**

| | |
|---|---|
| Discount rate | 5.75% |
| Rate of compensation increase | N/A |
| Expected long-term return on plan assets | 5.00% |
| Health care cost trend rates (graded to 4.75% by year 2012) | 12.00% |

FGT employs a building block approach in determining the expected long-term rate on return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term market assumptions are determined. The long-term portfolio return is established via a building block approach with proper consideration of diversification and rebalancing. Peer data and historical returns are reviewed to check for reasonability and appropriateness.

The sensitivity to changes in assumed health care cost trend rates for FGT's OPEB is as follows:

| (in thousands) | One Percentage Point Increase | One Percentage Point Decrease |
|---|---|---|
| Effect on total service and interest cost components | $ 19 | $ (17) |
| Effect on postretirement benefit obligation | $ 341 | $ (303) |

**Discount Rate Selection** – The discount rate for each measurement date is selected via a benchmark approach that reflects comparative changes in the Moody's Long Term Corporate Bond Yield for AA Bond ratings with maturities 20 years and above and the Citigroup Pension Liability Index Discount Rate.

The result is compared for consistency with the single rate determined by projecting the aggregate employer provided benefit cash flows from each plan for each future year, discounting such projected cash flows using annual spot yield rates published as the Citigroup Pension Discount Curve on the Society of Actuaries website for each measurement date and determining the single discount rate that produces the same discounted value. The result is rounded to the nearest multiple of 25 basis points.

**Plan Asset Information** – The plan assets shall be invested in accordance with sound investment practices that emphasize long-term investment fundamentals. An investment objective of income and growth for the plan has been adopted. This investment objective: (i) is a risk-averse balanced approach that emphasizes a stable and substantial source of current income and some capital appreciation over the long-term; (ii) implies a willingness to risk some declines in value over the short-term, so long as the plan is positioned to generate current income and exhibits some capital appreciation; (iii) is expected to earn long-term returns sufficient to keep pace with the rate of inflation over most market cycles (net of spending and investment and administrative expenses), but may lag inflation in some environments; (iv) diversifies the plan in order to provide opportunities for long-term growth and to reduce the potential for large losses that could occur from holding concentrated positions; and (iv) recognizes that investment results over the long-term may lag those of a typical balanced portfolio since a typical balanced portfolio tends to be more aggressively invested. Nevertheless, this plan is expected to earn a long-term return that compares favorably to appropriate market indices.

It is expected that these objectives can be obtained through a well-diversified portfolio structure in a manner consistent with the investment policy.

FGT's OPEB weighted-average asset allocation by asset category for the $1.2 million of assets actually in the VEBA Trust at December 31, 2005 is as follows:

| | Year Ended December 31, 2005 |
|---|---|
| Equity securities | 0% |
| Debt securities | 0% |
| Cash and cash equivalents | 100% |
| Total | 100% |

## (7) Major Customers

Revenues from individual third party and affiliate customers exceeding 10 percent of total revenues for the years ended December 31, 2005, 2004 and 2003 were approximately as listed below (in millions), and in total represented 54%, 50% and 46% of total revenue, respectively.

| Customers | 2005 | 2004 | 2003 |
|---|---|---|---|
| Florida Power & Light Company | $ 181.5 | $ 189.5 | $ 186.6 |
| Teco Energy, Inc. | $ 76.1 | $ 69.0 | $ 66.1 |

At December 31, 2005 and 2004 the Company had receivables of approximately $14.8 million and $15.0 million from Florida Power & Light Company and approximately $5.4 million and $5.0 million from Teco Energy, Inc., and subsidiaries, respectively.

## (8) Related Party Transactions

In December 2001 Enron and certain of its subsidiaries filed voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy court. At December 31, 2004 FGT and Trading had aggregate outstanding claims with the Bankruptcy Court against Enron and affiliated bankrupt companies of $220.6 million. Of these claims, FGT and Trading filed claims totaling $68.1 and $152.5 million, respectively. FGT and Trading claims pertaining to contracts rejected by ENA were $21.4 and $152.3 million, respectively. In March 2005, ENA filed objections to Trading's claim. The

Bankruptcy Court heard arguments on Trading's claim against ENA and the matter is awaiting decision.

FGT's claims against ENA on transportation contracts were reduced by approximately $21.2 million when a third party took assignment of ENA's transportation contracts. In 2004 FGT settled the amount of all of its claims (including the deferred compensation retiree claim (see Note 6)) against Enron and a subsidiary debtor. Total allowed claims (including debtor set-offs) were $13.3 million. After approval of the settlement by the Bankruptcy Court, in June 2005 FGT sold its claims, received $3.4 million and recorded Other Income of $0.9 million.

FGT had a construction reimbursement agreement with ENA under which amounts owed to FGT were delinquent. These obligations totaled approximately $7.4 million and were included in FGT's filed bankruptcy claims. These receivables were fully reserved by FGT prior to 2003. Under the Settlement filed by FGT on August 13, 2004 and approved by the FERC on December 21, 2004 FGT will recover the under-recovery on this obligation by rolling in the costs of the facilities constructed, less the recovery from ENA, in its tariff rates (see Note 9). As part of the June 2005 sale of its claims, FGT received $2.1 million for this part of the claim.

The Company provided natural gas sales and transportation services to El Paso affiliates at rates equal to rates charged to non-affiliated customers in the same class of service. Revenues related to these transportation services were approximately $4.5, $3.7 and $5.3 million for the years ended December 31, 2005, 2004 and 2003, respectively. The Company's gas sales were approximately $0.0, $0.1 and $9.2 million for the years ended December 31, 2005, 2004 and 2003, respectively. The Company also purchased gas from affiliates of Enron of approximately $0.0, $5.8 and $3.7 million and from affiliates of El Paso of approximately $0.0, $19.5 and $26.9 million for the years ended December 31, 2005, 2004 and 2003, respectively. FGT also purchased transportation services from Southern in connection with its Phase III Expansion completed in early 1995. FGT contracted for firm capacity of 100,000 Mcf/day on Southern's system for a primary term of 10 years, to be continued for successive terms of one year each thereafter unless cancelled by either party, by giving 180 days notice to the other party prior to the end of the primary term or any yearly extension thereof. The amount expensed for these services totaled $6.3, $6.5 and $6.6 million for the years ended December 31, 2005, 2004 and 2003, respectively.

FGT entered into a 20-year compression service agreement with Enron Compression Services Company (ECS) in March 2000, as amended, service under which commenced on April 1, 2002. This agreement required FGT to pay ECS to provide electric horsepower capacity and related horsepower hours to be used to operate an electric compressor unit within Compressor Station No. 13A. Amounts paid to ECS in 2004 and 2003 totaled $2.4 and $2.3 million, respectively. Under related agreements, ECS is required to pay FGT an annual lease fee and a monthly operating and maintenance fee to operate and maintain the facilities. Amounts received from ECS in 2004 and 2003 for these services were $0.4 and $0.4 million, respectively. A Netting Agreement, dated effective November 1, 2002, was executed with ECS, providing for the netting of payments due under each of the O&M, lease, and compression service agreements with ECS. Effective December 1, 2004, ECS assigned all of its interest in the compression services and related agreements to Paragon ECS Holdings, LLC, a non-affiliated entity.

Related to Enron's bankruptcy, the Bankruptcy Court authorized an overhead expense allocation methodology on November 25, 2002. In compliance with the authorization, recipient companies subject to regulation and rate base constraints may limit amounts remitted to Enron to an amount equivalent to 2001, plus quantifiable adjustments. The Company has invoked this regulation and rate base constraint limitation in the calculation of expenses accrued for January 1 through March 31, 2004. Effective April 1, 2004 services previously provided by bankrupt Enron affiliates to the

Company pursuant to the allocation methodology ordered by the Bankruptcy Court were covered and charged under the terms of the Transition Services Agreement/Transition Supplemental Services Agreement (TSA/TSSA). This agreement between Enron and CrossCountry is administered by CrossCountry Energy Services, LLC (CCES), an affiliate of CCEH, which has allocated to the Company its share of total costs. Effective November 17, 2004 an Amended TSA/TSSA agreement was put into effect. This agreement expired on July 31, 2005. The total costs are not materially different from those previously charged. The Company expensed administrative expenses from Enron and affiliated service companies of approximately \$8.4 and \$12.1 million, including insurance cost of approximately \$6.7 and \$6.9 million, for the year ended December 31, 2004 and 2003, respectively. The amount expensed for the seven months period ended July 31, 2005 was approximately \$1.5 million.

Effective November 5, 2004 CCEH entered into an Administrative Services Agreement (ASA) with SU Pipeline Management LP (Manager), a wholly owned subsidiary of Southern Union. Pursuant to the ASA, Manager is responsible for the operations and administrative functions of the enterprise, CCEH and Manager will share certain operations of Manager and its affiliates, and CCEH will be obligated to bear its share of costs of the Manager and its affiliates, as well as certain transition costs. Costs are allocated by Manager and its affiliates to the operating subsidiaries and investees, based on relevant criteria, including time spent, miles of pipe, total assets, labor allocations, or other appropriate methods. Transition costs are non-recurring costs of establishing the shared services, including but not limited to severance costs, professional fees, certain transaction costs, and the costs of relocating offices and personnel.

The Company recognizes costs of shared services allocated under the ASA by Southern Union. Amounts expensed by the Company were \$1.6 and \$0.0 million in the years ended December 31, 2005 and 2004, respectively. Shared services are also exchanged between other affiliate companies.

In 2005, the Company paid a subsidiary of CCEH \$9.6 million to settle the Cash Balance Plan obligation, which CCEH effectively paid in conjunction with the 2004 acquisition of the Company.

Citrus paid cash dividends to its shareholders of \$121.2, \$140.0 and \$0.0 million in 2005, 2004 and 2003, respectively.

## (9) Regulatory Matters

On October 1, 2003 FGT filed a general rate case, proposing rate increases for all services, based upon a cost of service of approximately \$167.0 million for the pre-expansion system and approximately \$342.0 million for the incremental system. By order issued October 31, 2003 FERC accepted and suspended the effectiveness of FGT's proposed rates for the statutory period of five months, effective April 1, 2004. On August 13, 2004 FGT filed a Stipulation and Agreement of Settlement ("Settlement"), which established settlement rates and resolved all issues. The settlement rates became effective on April 1, 2005.

On December 15, 2003 the U.S. Department of Transportation issued a Final Rule requiring pipeline operators to develop integrity management programs to comprehensively evaluate their pipelines, and take measures to protect pipeline segments located in what the regulation defines as "high consequence areas" ("HCA"). This rule resulted from the enactment of the Pipeline Safety Improvement Act of 2002, a bill signed into law on December 17, 2002. The rule requires operators to identify HCAs along their pipelines by December 2004 and to have begun baseline integrity assessments, comprised of in-line inspection (smart pigging), hydrostatic testing, or direct assessment, by June 2004. Operators must risk rank their pipeline segments containing HCAs, and must complete assessments on at least 50 percent of the segments using one or more of these methods by December 2007. Assessments will generally be conducted on the higher risk segments first with the balance being completed by December 2012. The costs of utilizing these methods typically range from a few thousand dollars per mile to in excess of $15,000 per mile. In addition, some system modifications will be necessary to accommodate the in-line inspections. While identification and location of all the HCAs has been completed, it is impossible to determine the scope of required remediation activities prior to completion of the assessments and inspections. Therefore, the cost of implementing the requirements of this regulation is impossible to determine at this time. The required modifications and inspections are estimated to be in the range of approximately $12-$22 million per year, inclusive of remediation costs. In the August 13, 2004 Settlement of the rate case, FGT has the right to make limited sections 4 filings to recover such costs beginning in April 2006 (if the threshold is met), via a surcharge, depreciation and return on up to approximately $40 million in security, integrity assessment and repair costs, and Florida Turnpike relocation and modification costs. Costs incurred in 2005 are expected to create a surcharge of $0.01 per MMBtu effective on April 1, 2006.

In June 2005 FERC issued an order Docket No. AI05-1-000 that expands on the accounting guidance in the proposed accounting release issued in November 2004 on mandated pipeline integrity programs. The order interprets the FERC's existing accounting rules and standardizes classifications of expenditures made by pipelines in connection with an integrity management program. The order is effective for integrity management expenditures incurred on or after January 1, 2006. FGT capitalizes all pipeline assessment costs based on its FERC Settlement dated December 21, 2004. The Settlement contains no reference to the FERC Docket No. AI05-1-000 regarding pipeline assessment costs. The Settlement provides that the final FERC order approving the Settlement shall constitute final approval of all necessary authorizations to effectuate the provisions of the Settlement. The Settlement became effective on March 1, 2005 and new tariff sheets to implement the Settlement were filed on March 15, 2005. FERC issued an order accepting the tariff sheets on May 20, 2005. FGT expects the cost of pipeline assessment programs, as a part of the integrity programs, to be approximately $8.8 million in 2006, and pursuant to its approved tariff and Settlement language, intends to capitalize such costs pending FERC review of its surcharge filing to be effective April 1, 2006.

On October 5, 2005 FGT filed an application with FERC for the Company's proposed Phase VII expansion project. The proposed project will expand FGT's existing pipeline infrastructure in Florida and provide the growing Florida energy market access to additional natural gas supply from the Southern LNG Elba Island liquefied natural gas import terminal near Savannah, Georgia. The Phase VII project calls for FGT to build approximately 33 miles of 36-inch diameter pipeline looping in several segments along an existing right of way and install 9,800 horsepower of compression to be constructed in two phases. The expansion will provide about 160 million cubic feet per day of additional capacity to transport natural gas from a connection with Southern Natural Gas Company's proposed Cypress Pipeline project in Clay County, Florida. The project is expected to be in service in May 2007 and May 2009. The estimated cost of expansion is up to approximately $104 million.

**(10) Property, Plant and Equipment**

The principal components of the Company's Property, Plant and Equipment at December 31, 2005 and 2004 are as follows (in thousands):

| | 2005 | 2004 |
|---|---|---|
| Transmission Plant | $ 2,812,586 | $ 2,783,798 |
| General Plant | 26,383 | 25,136 |
| Intangible Plant | 27,083 | 23,738 |
| Construction Work-in-progress | 9,693 | 12,202 |
| Acquisition Adjustment | 1,252,466 | 1,252,466 |
| | 4,128,211 | 4,097,340 |
| Less: Accumulated depreciation and amortization | (1,211,663) | (1,130,593) |
| Property, Plant and Equipment, net | $ 2,916,548 | $ 2,966,747 |

**(11) Other Assets**

The principal components of the Company's regulatory assets at December 31, 2005 and 2004 are as follows (in thousands):

| | 2005 | 2004 |
|---|---|---|
| Ramp-up assets, net(1) | $ 12,240 | $ 12,552 |
| Cash balance plan settlement (see Note 6) | 6,047 | 7,907 |
| OPEB | 2,173 | — |
| Environmental non-PCB clean-up cost (see Note 13) | 1,000 | — |
| Other miscellaneous | 2,632 | 2,381 |
| Total Regulatory Assets | $ 24,092 | $ 22,840 |

*(1) Ramp-up assets is a regulatory asset FGT was specifically allowed to establish in the FERC certificates authorizing the Phase IV and V Expansion projects.*

The principal components of the Company's other assets at December 31, 2005 and 2004 are as follows (in thousands):

| | 2005 | 2004 |
|---|---|---|
| Long-term receivables | $ 72,570 | $ 73,077 |
| Fuel tracker | — | 11,165 |
| Other miscellaneous | 2,323 | 2,204 |
| Total Other Assets — Other | $ 74,893 | $ 86,446 |

**(12) Deferred Credits**

Regulatory liabilities were $9.0 million and $5.3 million at December 31, 2005 and 2004, respectively. These consisted of balancing tools, which are a regulatory method by which FGT recovers the costs of operational balancing of the pipeline's system. The balance can be a deferred charge or credit, depending on timing, rate changes and operational activities.

The principal components of the Company's other deferred credits at December 31, 2005 and 2004 are as follows (in thousands):

| | 2005 | 2004 |
|---|---|---|
| Post construction mitigation costs | $ 2,600 | $ 3,296 |
| Construction prepayments | 4,536 | — |
| Customer deposits (see Note 15) | 1,249 | 1,306 |
| Phase IV retainage & Phase V surety bond | — | 1,459 |
| Fuel Tracker | 14,477 | — |
| Deferred compensation (see Note 6) | 1,425 | 1,768 |
| Environmental non-PCB clean-up cost reserve (see Note 13) | 1,631 | — |
| Tax contingency | 2,594 | — |
| Asset retirement obligation (see Note 2) | 493 | — |
| OPEB (see Note 6) | 2,173 | — |
| Miscellaneous | 1,892 | 142 |
| Total Deferred Credits — Other | $ 33,070 | $ 7,971 |

**(13) Environmental Reserve**

The Company is subject to extensive federal, state and local environmental laws and regulations. These laws and regulations require expenditures in connection with the construction of new facilities, the operation of existing facilities and for remediation at various operating sites. The implementation of the Clean Air Act Amendments is expected to result in increased operating expenses. These increased operating expenses are not expected to have a material impact on the Company's consolidated financial statements.

FGT conducts assessment, remediation, and ongoing monitoring of soil and groundwater impact which resulted from its past waste management practices at its Rio Paisano and Station 11 facilities. The anticipated costs over the next five years are: 2006 — $0.1 million, 2007 — $0.2 million, 2008 — $0.3 million, 2009 — $0.1 million and 2010 — $0.2 million. The expenditures thereafter are estimated to be $0.9 million for soil and groundwater remediation. The liability is recognized in other current liabilities and other deferred credits (Note 12) and totals $1.7 million. The anticipated costs to April 1, 2010 of $0.8 million have been expensed during the year ended December 31, 2005. FGT recorded the estimated costs of remediation to be spent after April 1, 2010 of $1.0 million as a regulatory asset based on the probability of recovery in rates in its next rate case (Note 11).

As of December 31, 2004, no such liability was recognized since the liability was previously estimated to be less than $1 million, and therefore, considered not to be material. Amounts incurred for environmental assessment and remediation were expensed as incurred.

**(14) Commitments and Contingencies**

In the normal course of business, the Company is involved in litigation, claims or assessments that may result in future economic detriment. The Company evaluates each of these matters and determines if loss accruals are necessary as required by SFAS No. 5, *Accounting for Contingencies.* The Company does not expect to experience losses that would be materially in excess of the amount accrued at December 31, 2005, 2004 and 2003.

FGT and Trading have filed bankruptcy related claims against Enron and other affiliated bankrupt companies totaling $220.6 million. Of these claims, FGT and Trading filed claims totaling $68.1 and

$152.5 million, respectively. FGT's claim includes rejection damages and delinquent amounts owed under certain transportation agreements, an unpaid promissory note, and other fees for services and imbalances. Subsequent to FGT's filing its claims, ENA's firm transportation agreements were permanently relinquished to a creditworthy party, which significantly reduced FGT's rejection damages. Trading's claim is for rejection damages on two physical/financial swaps and a gas sales contract, as well as certain delinquent amounts owed pre-petition. FGT and Enron agreed on the amount of the claim at $13.3 million, with payout subject to the bankruptcy proceedings. FGT assigned its claims to a third party and received $3.4 million in June 2005. In March 2005, ENA filed objections to Trading's claim. The Bankruptcy court heard arguments on Trading's claim and the matter is awaiting the court's decision.

On March 7, 2003 Trading filed a declaratory order action, involving a contract between it and Duke. Trading requested that the court declare that Duke breached the parties' natural gas purchase contract by failing to provide sufficient volumes of gas to Trading. The suit seeks damages and a judicial determination that Duke has not suffered a "loss of supply" under the parties' contract, which could, if it continued, have given rise to the right of Duke to terminate the contract at a point in the future. On April 14, 2003, Duke sent Trading a notice that the contract was terminated as of April 16, 2003 (due to Trading's alleged failure to timely increase the amount of a letter of credit); although it disagreed with Duke's position, Trading increased the letter of credit on April 15, 2003. Duke has answered and filed a counterclaim, arguing that Trading failed to timely increase the amount of a letter of credit, and that it has breached a "resale restriction" on the gas. Trading disputes that it has breached the agreement, or that any event has given rise to a right to terminate by Duke. On June 2, 2003, Trading notified Duke that, because Duke had defaulted and failed to cure, Trading was terminating the agreement effective as of June 5, 2003. On August 8, 2003 Trading sent its final "termination payment" invoice to Duke in the amount of $187 million. Trading moved for summary judgment and Duke cross-moved on the central issue of whether Duke's failure to perform was justified under the letter of credit requirements of the agreements. The Judge denied the motions from both parties in his ruling dated August 23, 2005. Trading has filed additional motions for summary judgment on the loss of supply issue and other remaining issues. Duke has cross-moved and the matters are fully briefed and awaiting decision. This is a disputed matter, and there can be no assurance as to what amounts, if any, Trading will ultimately recover. Management believes that the amount ultimately recovered will not be materially different than the amount recorded as a receivable at December 31, 2005 and that the ultimate resolution of this matter will not have a materially adverse effect on the Company's consolidated financial position, results of operations or cash flows. Management further believes that claims made by Duke against the Company with regard to this matter do not constitute a liability which would require adjustment to the Company's consolidated financial statements in accordance with SFAS No. 5, *Accounting for Contingencies.*

The Florida Department of Transportation, Florida's Turnpike Enterprise (FDOT/FTE) has various turnpike widening projects in the planning stages, which may, over the next ten years, impact one or more of FGT's mainline pipelines that are co-located in FDOT/FTE rights-of-way. Under certain conditions, the existing agreements between FGT and the FDOT/FTE require the FDOT/FTE to provide any new right-of-way needed for relocation of the pipelines and for FGT to pay for rearrangement or relocation costs. Under certain other conditions, FGT may be entitled to reimbursement for the costs associated with relocation, including construction and right of way costs. On April 8, 2005 FGT filed a complaint in the Ninth Judicial Circuit, Orange County, Florida seeking a declaratory judgment order finding among other things, that FGT has a compensable property interest in certain easements and agreements with the FDOT/FTE, and that: (a) FGT is entitled to recover: (i) compensation for all or any part of FGT's right-of-way to be taken, (ii) costs incurred and to be incurred by FGT for relocation of its pipeline in connection with FDOT/FTE's changes to State Road 91; and (iii) $5.5 million in expenditures in a prior relocation project (for which an invoice was presented to FDOT/FTE but FDOT/FTE refused to pay). FGT also seeks an order declaring that FDOT/FTE has a duty to avoid conflict at FGT facilities when reasonably possible and to provide sufficient rights-of-way to allow FGT to fully operate, relocate and maintain its facilities in a manner contemplated by the agreements or pay compensation for the loss of FGT's property rights. Trial date is set for June 13, 2006.

FGT is planning to replace approximately 11.3 miles of its existing 18 and 24 inch pipelines located in FDOT/FTE right of way between Griffin Road and Atlantic Avenue in Broward County, Florida with a single 36" pipeline starting fourth quarter 2006. Estimated cost of this project is $110 million. FGT is also in discussions with the FDOT/FTE related to two other projects, Heft to Griffin (7.5 miles) and Atlantic to Sawgrass (6.8 miles that may require relocation and replacements of FGT's 18 and 24 inch pipelines within FDOT/FTE right of way. The total actual amount of miles of pipe to be impacted ultimately for all of the FDOT/FTE widening projects, and the associated relocation and/or right-of-way costs, cannot be determined at this time.

## (15) Concentrations of Credit Risk and Other Financial Instruments

The Company has a concentration of customers in the electric and gas utility industries. These concentrations of customers may impact the Company's overall exposure to credit risk, either positively or negatively, in that the customers may be similarly affected by changes in economic or other conditions. Credit losses incurred on receivables in these industries compare favorably to losses experienced in the Company's receivable portfolio as a whole. The Company also has a concentration of customers located in the southeastern United States, primarily within the state of Florida. Receivables are generally not collateralized. From time to time, specifically identified customers having perceived credit risk are required to provide prepayments, deposits, or other forms of security to the Company. FGT sought additional assurances from customers due to credit concerns, and had customer deposits totaling $1.2 and $1.3 million and prepayments of $0.5 and $1.2 million for 2005 and 2004, respectively. The Company's Management believes that the portfolio of FGT's receivables, which includes regulated electric utilities, regulated local distribution companies, and municipalities, is of minimal credit risk.

The carrying amounts and fair value of the Company's financial instruments at December 31, 2005 and 2004 are as follows (in thousands):

| | 2005 | | 2004 | |
|---|---|---|---|---|
| | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| Long-term debt | $939,000 | $1,054,965 | $1,028,000 | $1,193,793 |

The carrying amount of cash and cash equivalents, accounts receivable and accounts payable reasonably approximate their fair value. The book value of the 2004 Revolver approximates its market value given the variable rate of interest. The fair value of long-term debt is based upon market quotations of similar debt at interest rates currently available (see Note 3).

## (16) Accumulated Other Comprehensive Income

Accumulated other comprehensive income is comprised of deferred gains and (losses) in connection with the termination of the following derivative instruments which were previously accounted for as cash flow hedges. Such amounts are being amortized over the terms of the hedged debt.

| (in thousands) | Termination Date | Original Gain/(Loss) | Amortization Period | Annual Amortization | Balance at December 31, 2005 | Balance at December 31, 2004 |
|---|---|---|---|---|---|---|
| Interest rate lock on 7.625% $325 million note due 2010 | December 2000 | $(18,724) | 10 years | $1,872 | $ 9,206 | $11,078 |
| Interest rate swap loss on 7.0% $250 million note due 2012 | July 2002 | (12,280) | 10 years | 1,228 | 8,035 | 9,263 |
| Interest rate swap gain on 9.19% $150 million note due 2005-2024 | November 1994 | 9,236 | 20 years | (462) | (4,079) | (4,541) |
| | | | | $2,638 | $13,162 | $15,800 |

**SOUTHERN NATURAL GAS COMPANY**

**EXHIBIT LIST**
**December 31, 2005**

Each exhibit identified below is a part of this Report. Exhibits filed with this Report are designated by "*". All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

| Exhibit Number | Description |
|---|---|
| 3.A | Restated Certificate of Incorporation dated as of March 7, 2002 (Exhibit 3.A to our 2001 Form 10-K). |
| 3.B | By-laws dated as of June 24, 2002. (Exhibit 3.B to our 2002 Form 10-K). |
| 4.A | Indenture dated June 1, 1987 between Southern Natural Gas Company and Wilmington Trust Company (as successor to JPMorgan Chase Bank, formerly known as The Chase Manhattan Bank), as Trustee (Exhibit 4.1 to our Registration Statement on Form S-3 filed January 15, 2002, File No. 333-76782); First Supplemental Indenture, dated as of September 30, 1997, between Southern Natural Gas Company and the Trustee (Exhibit 4.1 to our Registration Statement on Form S-3 filed January 15, 2002, File No. 333-76782); Second Supplemental Indenture dated as of February 13, 2001, between Southern Natural Gas Company and the Trustee. (Exhibit 4.1 to our Registration Statement on Form S-3 filed January 15, 2002, File No. 333-76782). |
| 4.B | Indenture dated as of March 5, 2003 between Southern Natural Gas Company and The Bank of New York Trust Company, N.A., successor to The Bank of New York, as Trustee (Exhibit 4.1 to our Form 8-K filed March 5, 2003). |
| 10.A | Amended and Restated Credit Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the several banks and other financial institutions from time to time parties thereto and JPMorgan Chase Bank, N.A., as administrative agent and as collateral agent (Exhibit 99.B to our Form 8-K filed November 29, 2004); Amended and Restated Subsidiary Guarantee Agreement dated as of November 23, 2004, made by each of the Subsidiary Guarantors in favor of JPMorgan Chase Bank, N.A., as Collateral Agent (Exhibit 99.D to our Form 8-K filed November 29, 2004). |
| 10.B | Amended and Restated Security Agreement dated as of November 23, 2004, among El Paso Corporation, ANR Pipeline Company, Colorado Interstate Gas Company, El Paso Natural Gas Company, Tennessee Gas Pipeline Company, the Subsidiary Grantors and certain other credit parties thereto and JPMorgan Chase Bank, N.A., not in its individual capacity, but solely as collateral agent for the Secured Parties and as the depository bank (Exhibit 99.C to our Form 8-K filed November 29, 2004). |
| 21 | Omitted pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K. |
| *31.A | Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| *31.B | Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002. |
| *32.A | Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |
| *32.B | Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

## Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the U.S. Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and our consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, Southern Natural Gas Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 15th day of March 2006.

**SOUTHERN NATURAL GAS COMPANY**

By: /s/ JAMES C. YARDLEY

James C. Yardley
*Chairman of the Board and President*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Southern Natural Gas Company and in the capacities and on the dates indicated:

| Signature | Title | Date |
|---|---|---|
| /s/ JAMES C. YARDLEY<br>James C. Yardley | Chairman of the Board and President<br>(Principal Executive Officer) | March 15, 2006 |
| /s/ JOHN R. SULT<br>John R. Sult | Senior Vice President,<br>Chief Financial Officer and Controller<br>(Principal Accounting and Financial Officer) | March 15, 2006 |
| /s/ DANIEL B. MARTIN<br>Daniel B. Martin | Senior Vice President and Director | March 15, 2006 |
| /s/ NORMAN G. HOLMES<br>Norman G. Holmes | Vice President and Director | March 15, 2006 |