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**TECO ENERGY** INC

# 2004 Annual Report
# & Proxy Statement

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## Dear Shareholders:

During the past year we continued to focus on our core businesses: the regulated utilities, Tampa Electric and Peoples Gas System, and our three established unregulated businesses, TECO Coal, TECO Transport and our Guatemalan operations. This focus guides all of our actions, and all of our business decisions. Some decisions and actions have been difficult, but all have been made with the goal of increasing shareholder value.

### Our core businesses

In 2004, Tampa Electric and Peoples Gas continued to have strong customer and energy sales growth. Tampa Electric celebrated the dedication and full commercial operation of the repowered H.L. Culbreath Bayside Power Station, providing more than 1,700 megawatts of natural gas-fueled generation to serve the company's 625,000 customers. For their heroic response to the unprecedented hurricane season of 2004, the men and women of Tampa Electric were awarded the Edison Electric Institute's Emergency Response Award, an award shared with other utilities in the region.

TECO Coal has benefited from rising coal prices, and we expect that trend to continue to benefit that business. And, despite a challenging year, TECO Transport saw improvements in rates for river barge services and higher volumes at our terminal on the Mississippi River late in the year. We believe these events signal an improvement in the transportation markets. Our Guatemalan operations had an outstanding year, with continued customer and energy sales growth.

### Our discontinued businesses

We took a series of actions during the past year to reduce our exposure to the depressed merchant power sector. These actions included the sale of significant assets – like our interest in the Texas Independent Energy projects, and Frontera Power Station – and the announced sale of our Commonwealth Chesapeake Power Station. We also recorded large valuation adjustments on some of our power projects. I am confident these actions, though difficult, are the right things for our shareholders, our company and our people. We continue to make progress on the transfer of the two largest merchant holdings, Union and Gila River, and are expecting to complete the transfer of them to the lending group by mid-year.

While the actions we took to reduce our exposure to merchant power resulted in some very significant one-time charges to earnings, the tough decisions that we have made give us confidence in our future. Our core businesses have remained strong performers, and our results in 2004, excluding the valuation adjustments and write-offs, reflect the strength of these businesses.

### Our 2005 outlook

Looking ahead to 2005, we're expecting continued strong customer and energy sales growth at Tampa Electric and Peoples Gas. Tampa Electric is embarking on a $300-million environmental improvement project to further reduce nitrogen oxide emissions at its Big Bend Power Station, which will make the facility among the cleanest pulverized coal-fired plants in the nation.

At TECO Transport, we're already seeing improvements in waterborne transportation markets. At TECO Coal, 97% of our production is under contract for 2005, at prices 40% higher than prices in 2004. Our fully contracted power generation operations in Guatemala and our ownership interest in Guatemala's largest distribution utility are also expected to continue their strong operating performance and contributions to our bottom line.

### Our future

Not only have we reduced our exposure to the volatile merchant power sector, we have significantly improved TECO Energy's financial outlook as we begin 2005. Our cash and liquidity outlook has greatly improved. And though forecasts can be influenced by many factors, current longer-term expectations indicate that our cash position will allow us to retire most or all of the $680 million of TECO Energy corporate debt maturing in 2007, while at the same time meeting the capital spending needs of our core businesses and continuing our dividend.

With difficult decisions relating to our unregulated power investments behind us, our path forward is more clearly defined, and we expect that the actions we have taken will result in enhanced operational performance and shareholder value in 2005 and beyond.

As always, our efforts are driven by our desire to produce strong returns for our shareholders. On behalf of the Board of Directors, and all the men and women of TECO Energy, I want to express appreciation for the loyalty and continued support of our shareholders, customers and suppliers. We thank you for your continued interest and confidence in us.

Sincerely,

Sherrill W. Hudson

Sherrill W. Hudson
Chairman and CEO

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### Annual Report

*This Management's Discussion and Analysis contains forward-looking statements, which are subject to the inherent uncertainties in predicting future results and conditions. Actual results may differ materially from those forecasted. These forward-looking statements include references to TECO Energy's anticipated capital investments, liquidity and financing requirements, projected operating results, future transactions and other plans. Certain factors that could cause actual results to differ materially from those projected in these forward-looking statements include: general economic conditions in Tampa Electric's and Peoples Gas' service areas affecting energy and gas sales; economic conditions, both national and international, affecting the demand for TECO Transport's waterborne transportation services; state or federal regulatory actions that could reduce revenues or increase costs at all of TECO Energy's operating companies; weather variations affecting energy and gas sales and operating costs at Tampa Electric and Peoples Gas and the effect of extreme weather conditions; commodity price changes affecting the margins at TECO Coal; and the ability of TECO Energy's subsidiaries to operate equipment without undue accidents, breakdowns or failures. Additional factors that could impact actual results include: the ability to complete the planned transfer of the Union and Gila River power stations to the lending group in the time frame anticipated; the ability to complete the sale of the Commonwealth Chesapeake Power Station; any debt extinguishment costs or premiums associated with the early retirement of TECO Energy debt; unexpected capital needs or unanticipated reductions in cash flow that affect liquidity; declines in the anticipated waterborne fuel volumes transported by TECO Transport for Tampa Electric; TECO Coal's ability to successfully operate its synthetic fuel production facilities in a manner qualifying for Section 29 federal income tax credits, which could be impacted by changes in law, regulation or administration; and materially adverse outcomes in the disclosed litigation. Some of these factors and others are discussed more fully under* ***"Investment Considerations."***

*TECO Energy, Inc. is a holding company, and all of its business is conducted through its subsidiaries. In this Management's Discussion and Analysis, "we," "our," "ours" and "us" refer to TECO Energy, Inc. and its consolidated group of companies, unless the context otherwise requires.*

## *Overview*

Our actions in 2004 were driven by the implementation of the strategy announced in April 2003, which is to focus on our regulated utility operations in the high-growth Florida markets and our other profitable unregulated businesses and to reduce our exposure to the merchant power sector. A major component of this effort was an agreement to exit our ownership of the Union and Gila River power stations and to transfer the ownership of these power stations, which are part of the TECO Wholesale Generation (TWG) segment of TECO Energy that has been involved heretofore in merchant power activities. The exit strategy, which was announced in February 2004, is to transfer the ownership of these power stations to the lending group.

The continued generally poor financial performance at our other merchant power plants contributed to additional actions completed in 2004 that further reduced our exposure to the merchant power markets. (Merchant power plants are power plants that are not part of regulated utility operations, operate in the wholesale power market, and do not have long term contracts for the majority of their output. Most of the power from a merchant power plant is sold under short term agreements or in the more volatile wholesale power spot markets.) These actions included the sale of our 50% ownership interest in Texas Independent Energy (TIE), owner of two power plants in Texas; the sale of our 100% ownership interest in the Frontera Power Station in Texas; and the announcement in January 2005 of an agreement to sell the Commonwealth Chesapeake Power Station in Virginia. We experienced losses and value impairments on these sales and anticipated sales. In addition, we recognized an impairment of the value of the unfinished Dell and McAdams power stations, which there is a high probability we will no longer complete, to reflect the current market value for these plants. In 2004, we also sold the remaining major businesses in TECO Solutions, our small engineering and energy services unit, which operated in Florida as an adjunct to Peoples Gas. Some were sold at a gain and some at a loss. The components of TECO Solutions were acquired four or five years ago when it appeared that the Florida energy market would become more competitive.

With the commercial operation of the second phase of Tampa Electric's H.L. Culbreath Bayside Power Station (Bayside) in January 2004, we completed the major power generation construction programs at Tampa Electric and TWG. With the construction programs complete, in 2004 we were able to build strong liquidity for normal operations and to begin accumulating the cash to position us to pay off all or the majority of our debt maturities in 2007.

For more than three months beginning in mid-August, Tampa Electric, Peoples Gas and TECO Transport were focused on either preparing for or recovering from the succession of major hurricanes that impacted Florida and surrounding states. Tampa Electric's service area was directly impacted by three of the storms, each of which caused varying degrees of damage to its facilities and widespread customer outages. TECO Transport suffered no significant facility or equipment damage; however, its operations were disrupted by all four storms (see the **Tampa Electric** and **TECO Transport** sections).

Our financial results in 2004 were driven by the write-offs and valuation adjustments taken in the course of the year to eliminate the future risk to earnings and cash flow from the merchant power sector (see the **Results Summary** and **TWG-Merchant** sections).

The operations of the five core businesses, Tampa Electric, Peoples Gas, TECO Coal, TECO Transport and the Guatemalan operations, were sound in 2004. While TECO Transport experienced difficult market and operating conditions in the course of the year, these five companies produced good operating results. (See the individual operating companies for a detailed discussion of their respective results.)

## *Results Summary*

Our financial results for 2004 reflect the write-offs resulting from the sales of our merchant generating assets and asset valuation adjustments associated with the remaining unfinished merchant power plants. The net loss in 2004 was $552.0 million, primarily due to $555.6 million of charges and gains detailed in the **2004 Non-operating Items Affecting Net Income** table. The net loss from continuing operations in 2004 was $404.4 million, compared with net income from continuing operations of $61.7 million in 2003. Non-GAAP (Generally Accepted Accounting Principles) results from continuing operations excluding the charges and gains detailed in the **2004 Non-operating Items Affecting Net Income** table were $151.2 million in 2004, compared with $176.3 million in 2003. Results from discontinued operations in 2004 reflect primarily the operating results from the Frontera, Union and Gila River power stations, BCH Mechanical, and the 2004 write-offs and charges associated with these businesses.

The sale of our interests in our merchant generating assets in Texas, the announced sale of Commonwealth Chesapeake Power Station in Virginia, and the adjustment of the value of the unfinished Dell and McAdams power stations to reflect the current fair market value resulted in $562.5 million of after-tax write-offs in 2004, comprised of $482.6 million in continuing operations and $79.9 million in discontinued operations.

Results from continuing operations in 2004 were lower than 2003, primarily due to the write-offs associated with the merchant power plants and other charges detailed in the **2004 Non-operating Items Affecting Net Income** table. Excluding these charges and gains, results from continuing operations were lower due to the sale of an additional 40.5% membership interest in TECO Coal's synthetic fuel production facilities, much lower equity Allowance for Funds Used During Construction income (AFUDC, which represents allowed equity cost capitalized to construction costs) at Tampa Electric, and lower results at TECO Transport. The sale of the portion of the synthetic fuel production facilities is and will continue to generate significant cash, but earnings at a lower level, due to our continued role in operating the synthetic fuel production facilities at a time when TECO Energy cannot utilize the Section 29 tax credits. The net loss on a per share basis was $2.87 in 2004, compared with net loss of $5.05 in 2003. The loss from continuing operations on a per share basis was $2.10 in 2004, compared with earnings per share from continuing operations of $0.34 in 2003. The number of average shares outstanding at Dec. 31, 2004 was 7% higher than at Dec. 31, 2003 primarily due to the shares issued in the early settlement offer for our equity security units completed in August.

In 2003, results from continuing operations were lower than in 2002, primarily due to charges associated with the impairment of some of our merchant power assets, charges for corporate restructuring and staffing reductions, valuation adjustments at the energy services companies and limitations on the use of tax credits (see the table **2003 Non-operating Items Affecting Net Income**). Excluding these charges and gains, results from continuing operations were lower due to higher depreciation and interest expense at Tampa Electric; continued weak results at TECO Transport due to lower coal tonnage for Tampa Electric and continued weakness in the river business; higher interest expense at the TECO Energy parent level associated with the debt incurred to fund the TWG projects; lower results from TWG's interest in the TIE projects in Texas; and the elimination of interest and support income from Panda Energy related to the TIE projects. These results were partially offset by the gain on the sale of Hardee Power Partners, higher operating results at TECO Coal from increased synthetic fuel production and sales, and the sale of the 49.5% membership interest in the synthetic fuel production facilities. The net loss on a per-share basis was $5.05 in 2003, compared with earnings of $2.15 per share in 2002. Earnings per share from continuing operations were $0.34 in 2003, compared with earnings per share from continuing operations of $1.75 in 2002. The average number of shares outstanding at Dec. 31, 2003 was more than 17% higher than at Dec. 31, 2002.

**2004 Earnings Summary**

| *(millions) Except per-share amounts* | *2004* | *2003* | *2002* |
|---|---|---|---|
| **Consolidated revenues** | **$ 2,669.1** | $ 2,598.3 | $ 2,510.5 |
| **Earnings (loss) per share – basic** | | | |
| Earnings per share | **$ (2.87)** | $ (5.05) | $ 2.15 |
| Discontinued operations | **(0.77)** | (5.37) | 0.40 |
| Earnings from continuing operations before cumulative effect of change in accounting principle | **(2.10)** | 0.34 | 1.75 |
| Cumulative effect of change in accounting principle | – | (0.02) | – |
| Earnings (loss) from continuing operations | **$ (2.10)** | $ 0.32 | $ 1.75 |
| **Earnings (loss) per share – diluted** | | | |
| Earnings per share | **$ (2.87)** | $ (5.04) | $ 2.15 |
| Discontinued operations | **(0.77)** | (5.36) | 0.40 |
| Earnings from continuing operations before cumulative effect of change in accounting principle | **(2.10)** | 0.34 | 1.75 |
| Cumulative effect of change in accounting principle | – | (0.02) | – |
| Earnings (loss) from continuing operations | **$ (2.10)** | $ 0.32 | $ 1.75 |
| Net income (loss) | **$ (552.0)** | $ (909.4) | $ 330.1 |
| Net income (loss) from discontinued operations | **(147.6)** | (966.8) | 61.6 |
| Charges and gains from continuing operations | **(555.6)** | (114.6) | (28.6) |
| Cumulative effect of change in accounting principle | – | (4.3) | – |
| Non-GAAP results from continuing operations (1) | **$ 151.2** | $ 176.3 | $ 297.1 |
| **Average common shares outstanding** | | | |
| Basic | **192.6** (4) | 179.9 (3) | 153.2 (2) |
| Diluted | **192.6** (4) | 180.2 (3) | 153.3 (2) |

(1) A non-GAAP financial measure is a numerical measure of historical or future financial performance, financial position or cash flow that includes amounts, or is subject to adjustments, that have the effect of including amounts, that are excluded from the most directly comparable GAAP measure so calculated and presented.
(2) Average shares outstanding for 2002 reflects the issuance of 15.525 million shares in June 2002 and 19.385 million shares in October 2002 amongst other issuances
(3) Average shares outstanding for 2003 reflects the issuance of 11 million shares in September amongst other issuances.
(4) Average shares outstanding for 2004 reflect the issuance of 10.2 million shares in September in conjunction with the early settlement of the 9.5% adjustable conversion-rate equity security units amongst other issuances.

**Non-GAAP Information**

Many times in this Management's Discussion and Analysis we will refer to non-GAAP results. Management uses non-GAAP results, which excludes certain charges and gains, to measure the performance of our operations. For a more complete discussion of our use of non-GAAP results see the **Non-GAAP Presentation** section.

2004 Non-operating Items Affecting Net Income

| *Net income impact (millions)* | *Tampa Electric* | *TWG Merchant* | *Peoples Gas* | *TECO Transport* | *TECO Coal* | *Other Unregulated* | *Parent/ Other* | *Total* |
|---|---|---|---|---|---|---|---|---|
| Merchant power valuations | $ – | $ 532.0 | $ – | $ – | $ – | $ – | $ – | $ 532.0 |
| Steam turbine valuations | – | – | – | – | – | 12.8 | – | 12.8 |
| Debt extinguishment | – | – | – | – | – | 6.7 | (0.5) | 6.2 |
| Taxes on cash repatriation | – | – | – | – | – | 17.4 | – | 17.4 |
| Asset impairment | – | – | – | 0.6 | – | – | – | 0.6 |
| TMDP arbitration reserve | – | (4.3) | – | – | – | – | – | (4.3) |
| Restructuring charges | – | – | 0.4 | 1.1 | – | – | 5.0 | 6.5 |
| Valuation adjustment | – | – | – | – | – | 3.4 | – | 3.4 |
| Tax credit reversals | – | – | – | – | (7.0) | – | – | (7.0) |
| Total charges | $ – | $ 527.7 | $ 0.4 | $ 1.7 | $ (7.0) | $ 40.3 | $ 4.5 | $ 567.6 |
| Gain on asset sales | $ – | $ – | $ – | $ – | $ – | $ 12.0 | $ – | $ 12.0 |
| Discontinued operations: | | | | | | | | |
| Valuation adjustments | $ – | $ 25.6 | $ – | $ – | $ – | $ 20.3 | $ – | $ 45.9 |

2003 Non-operating Items Affecting Net Income

| *Net income impact (millions)* | *Tampa Electric* | *TWG Merchant* | *Peoples Gas* | *TECO Transport* | *TECO Coal* | *Other Unregulated* | *Parent/ Other* | *Total* |
|---|---|---|---|---|---|---|---|---|
| Turbine valuations | $ 48.9 | $ – | $ – | $ – | $ – | $ 28.5 | $ – | $ 77.4 |
| Goodwill impairment | – | 16.3 | – | – | – | – | – | 16.3 |
| TMDP arbitration reserve | – | 26.7 | – | – | – | – | – | 26.7 |
| Restructuring charges | 6.1 | 0.3 | 2.6 | 1.0 | – | 3.6 | 1.6 | 15.2 |
| Project cancellation costs | – | – | – | – | – | 9.0 | – | 9.0 |
| Valuation adjustment | – | – | – | – | – | 3.2 | – | 3.2 |
| Tax credit reversals | – | – | – | – | 7.0 | 2.7 | – | 9.7 |
| Change in accounting | – | – | – | 0.8 | 0.3 | – | 3.2 | 4.3 |
| Total charges | $ 55.0 | $ 43.3 | $ 2.6 | $ 1.8 | $ 7.3 | $ 47.0 | $ 4.8 | $ 161.8 |
| Hardee Power Partners Gain on sale and operations | $ – | $ – | $ – | $ – | $ – | $ 42.9 | $ – | $ 42.9 |
| Discontinued operations: | | | | | | | | |
| Valuations adjustments | $ – | $ 806.9 | $ – | $ – | $ – | $ 20.7 | $ – | $ 827.6 |
| Loss on joint venture termination | $ – | $ 94.7 | $ – | $ – | $ – | $ – | $ – | $ 94.7 |
| Gain on sale of TECO Coalbed Methane | $ – | $ – | $ – | $ – | $ – | $ 23.5 | $ – | $ 23.5 |

## *Strategy and Outlook*

In April 2003, we announced that our business strategy would change to focus on our electric and gas utilities, which operate in the high-growth Florida market, and our long-term profitable unregulated businesses and to reduce our exposure to the merchant power sector. This change in strategic direction followed a series of major investments in unregulated domestic power generation facilities outside of Florida in the 2000 through 2003 period and other smaller investments in unregulated energy service providers within Florida, in anticipation of a movement toward competitive energy markets in Florida and other states in which we were investing in new power plants. During that same period, we also continued the development of the regulated electric and gas businesses in Florida, including significant additions to Tampa Electric's electric generation and Peoples Gas System (PGS) infrastructure.

After we had committed to the major investments in unregulated power, starting in late 2001 and early 2002, conditions in energy markets and the independent power business changed dramatically, which reduced the prospects for the profitability of the investments in our unregulated domestic independent power generation facilities. At the time we decided to expand the independent power operations, our strategy was to construct facilities and sign contracts for the majority of the output and have only a small percentage of the output in the spot, or merchant, market. The wholesale power market evolved differently, however, and most of these facilities' sales were short-term agreements and spot sales. During the same period, wholesale power prices declined significantly in markets across the country for many reasons, including a general slowing, or in some states a reversal, of the movement towards wholesale electric competition and the large amount of new generating capacity which came online in 2002 and 2003 that contributed to significant excess generating capacity in many areas of the country.

In April 2003, we also stated that we were ceasing any new development activities in the independent power business and would take steps to reduce our exposure to merchant power. Following the completion of the large Union and Gila River power stations, in the face of prolonged weak conditions in the merchant energy markets, in October 2003, we announced that we would invest little, if any, additional cash in the existing merchant generating plants. Following a thorough review of the outlook for the non-recourse, project-financed Union and Gila River power plants, and assessment of our ability to continue to support the plants, we decided to cease providing additional funding to the projects and to sell our ownership interest in these projects to the lending group or others (see the **TWG-Merchant** section).

In general, wholesale power prices remained weak in 2004, and the prospects for long-term price recovery appear poor for the next several years in markets where we had made major investments in unregulated power plants. These changed market conditions, persistent low power prices and lack of long-term contracts have caused weaker earnings and cash flow expectations and caused us to continue to delay some projects and sell others. These conditions led us to a number of actions in 2004 which, while resulting in additional write-offs and impairment charges, further reduced our merchant energy exposure.

In 2004, we completed sales of our interests in two of TWG's three operating merchant power projects, and in January 2005, we announced an agreement to sell the third. We also sold our unregulated energy service businesses in 2004 and in January 2005. With the elimination of these unprofitable and higher risk businesses, we are positioned to focus on our five core businesses: the electric and gas utilities, the unregulated coal and transportation businesses, and the profitable wholesale power generating plants with contracts and our distribution investment in Guatemala.

In 2002 and 2003, we took significant steps to meet the cash obligations and liquidity needs associated with the completion of our large construction program including asset sales, cancellation of projects, a dividend reduction and capital markets transactions. As discussed in the **Liquidity, Capital Resources** section, our current and future liquidity needs are lower than in previous years and are now at levels more appropriate for our expected significantly lower levels of capital expenditures and lower risk business profile.

With the elimination of the associated losses expected from the merchant power operations, we expect improved financial results, with contributions from our regulated businesses, Tampa Electric and PGS, and the profitable unregulated businesses. Capital expenditures, except for the required environmental capital expenditures at Tampa Electric, are expected to be near maintenance levels for the next several years. We have no significant corporate debt maturities until 2007. We expect to use free cash flow generated in the 2005 through 2007 period to retire all or the majority of our corporate debt maturing in 2007. We expect our financial results in 2005 to provide a base from which we will seek to return to a stronger financial position and improve earnings in the future. In addition, our goal, over time, through our actions to reduce debt and reduce business risk identified in our strategy is to return to an investment grade credit rating.

A major source of the cash that we expect to generate is through the sale of the membership interests in TECO Coal's synthetic fuel production facilities and the Section 29 tax credits generated by the ownership for the third-party owners. These tax credits will expire Dec. 31, 2007, and, while we cannot predict if these tax credits will be extended or renewed in their current form, we are assuming that there will be no change in the current legislation. Based on the assumption that the tax credits expire as scheduled, both net income and cash flow at TECO Coal are expected to decline in 2008 due to the loss of the benefits from the sale of the third-party ownership interests.

In 2008, TECO Coal expects to no longer produce synthetic fuel, but it expects to produce conventional coal at levels approximately the same as current total production (approximately 9 million tons). When production of synthetic fuel ends, TECO Coal will stop mining the high-cost coals currently being mined for use in the production of synthetic fuel and will stop operating the synthetic fuel production equipment, which are expected to reduce production costs. At that time, the earnings and cash flow from TECO Coal will be dependent on the selling price of coal in 2008, and its ability to manage production costs. Prior to the expiration of the Section 29 tax credits at the end of 2007, we expect to develop a strategy directed toward mitigating the reduction in earnings and cash flow that will result from the expiration. The strategy will be focused on optimizing our coal operations for operating in the post-Section 29 tax credit environment, and improving results from all of the operating companies, and reducing interest expense at the parent. Based on our cash flow projections and our expected ability to retire all or the majority of the $680 million of TECO Energy corporate debt maturing in 2007, we expect earnings and cash flow to benefit from lower interest expense and lower cash interest payments in 2008.

## *Operating Results*

Management's Discussion & Analysis of Financial Condition and Results of Operations utilizes TECO Energy's consolidated financial statements, which have been prepared in accordance with GAAP, to analyze the financial condition of the company. Our reported operating results are affected by a number of critical accounting estimates such as those involved in our accounting for regulated activities, asset impairment testing and others (see the **Critical Accounting Policies and Estimates** section).

The following table shows the unconsolidated revenues and net income and earnings per share contributions from continuing operations of our business segments (see **Note 14** to the **Consolidated Financial Statements**).

| *(millions) Except per share amounts* | | *2004* | *2003* | *2002* |
|---|---|---|---|---|
| **Unconsolidated Revenues** (1) | | | | |
| Regulated companies | Tampa Electric | $ 1,687.4 | $ 1,586.1 | $ 1,583.2 |
| | Peoples Gas System | 417.2 | 408.4 | 318.1 |
| Total regulated | | 2,104.6 | 1,994.5 | 1,901.3 |
| Unregulated companies | TECO Coal | 327.6 | 296.3 | 317.1 |
| | TECO Transport | 249.6 | 260.6 | 254.6 |
| | Other unregulated businesses | 36.6 | 173.5 | 215.8 |
| | TWG - Merchant | 37.3 | 32.8 | 28.0 |
| Total unregulated | | $ 651.1 | $ 763.2 | $ 815.5 |
| **Net Income (loss)** (2) | | | | |
| Regulated companies | Tampa Electric | $ 146.0 | $ 98.9 | $ 171.8 |
| | Peoples Gas System | 27.7 | 24.5 | 24.2 |
| Total regulated | | 173.7 | 123.4 | 196.0 |
| Unregulated companies | TECO Coal | 61.3 | 77.1 | 76.4 |
| | TECO Transport | 10.2 | 15.3 | 21.0 |
| | Other unregulated businesses | 12.1 | 23.2 | 27.0 |
| | TWG - Merchant | (583.0) | (99.8) | (15.7) |
| Total unregulated | | (499.4) | 15.8 | 108.7 |
| Financing/Other | | (78.7) | (77.5) | (36.2) |
| Net income (loss) from continuing operations | | $ (404.4) | $ 61.7 | $ 268.5 |
| Discontinued operations | | (147.6) | (966.8) | 61.6 |
| Net income (loss) before cumulative effect of change in accounting principle | | (552.0) | (905.1) | 330.1 |
| Cumulative effect of a change in accounting principle | | – | (4.3) | – |
| Net income | | $ (552.0) | $ (909.4) | $ 330.1 |

| | | | | |
|---|---|---|---|---|
| **Earnings per Share - Basic** (2) | | | | |
| Regulated companies | Tampa Electric | $ 0.76 | $ 0.55 | $ 1.12 |
| | Peoples Gas System | 0.14 | 0.14 | 0.16 |
| Total regulated | | 0.90 | 0.69 | 1.28 |
| Unregulated companies | TECO Coal | 0.32 | 0.43 | 0.50 |
| | TECO Transport | 0.06 | 0.08 | 0.14 |
| | Other unregulated businesses | 0.06 | 0.13 | 0.17 |
| | TWG - Merchant | (3.03) | (0.56) | (0.10) |
| Total unregulated | | (2.59) | 0.09 | 0.71 |
| Financing/Other | | (0.41) | (0.43) | (0.24) |
| Earnings (loss) per share from continuing operations | | $ (2.10) | $ 0.34 | $ 1.75 |
| Discontinued operations | | (0.77) | (5.37) | 0.40 |
| Earnings (loss) per share before cumulative effect of change in accounting principle | | (2.87) | (5.03) | 2.15 |
| Cumulative effect of a change in accounting principle | | – | (0.02) | – |
| EPS Total | | $ (2.87) | $ (5.05) | $ 2.15 |

(1) Revenues for all periods have been adjusted to reflect the presentation of energy marketing related revenues on a net basis and the reclassification of the results from those businesses that have been sold to discontinued operations (see the **Discontinued Operations** section). Unconsolidated revenues include inter-company transactions that are eliminated in the preparation of TECO Energy's consolidated financial statements.
(2) Segment net income is reported on a basis that includes internally allocated financing costs to the unregulated companies. Internally allocated finance costs for 2004, 2003 and 2002 were at pretax rates of 8%, 8% and 7%, respectively, based on the average investment in each unregulated subsidiary.

## *Tampa Electric*

**Electric Operations Results**

Tampa Electric's 2004 net income was $146.0 million, compared to $98.9 million in 2003. Non-GAAP results in 2003, which excluded turbine purchase cancellations and restructuring charges, were $153.9 million. These results were driven by lower non-fuel operating expenses, continued strong customer growth and higher energy sales offset by lower AFUDC equity, an $8.2 million after-tax disallowance by the Florida Public Service Commission (FPSC) for the recovery of a portion of the waterborne transportation costs for delivery of solid fuel (see the **Regulation** section), and weather patterns that resulted in 3% lower total-degree days than normal and almost 7% lower total-degree days than 2003, when total-degree days were more than 4% above normal. The equity component of AFUDC, from the Gannon to Bayside repowering project, decreased to $0.7 million, compared to $19.8 million in 2003.

Tampa Electric's net income in 2003 was $98.9 million, compared to $171.8 million in 2002. Non-GAAP results in 2003 were $153.9 million, excluding a $48.9 million after-tax write-off associated with combustion turbine purchase cancellation and a $6.1 million after-tax restructuring charge. The decrease was due to after-tax accelerated depreciation related to Gannon Station coal-fired assets of $22.6 million, a $5.1 million after-tax disallowance by the FPSC for operations and maintenance expenses for the Gannon Station, lower AFUDC equity and higher interest expense. The expense items previously noted, lower sales to other utilities and decreased sales to phosphate customers more than offset continued good residential and commercial customer growth, lower operations and maintenance expenses and more favorable summer weather. The equity component of AFUDC decreased to $19.8 million in 2003, compared to $24.9 million in 2002 due to the April in-service date of Bayside Unit 1.

In 2004, Tampa Electric's service area was impacted by hurricanes Charley, Frances and Jeanne. These storms caused more than 600,000 customer outages and damaged the transmission and distribution systems and other facilities. The restoration costs were expected to be $72 million, which exceeded Tampa Electric's $44 million year-end unfunded storm damage reserve balance. Although rate base, operations and maintenance expense and capital expenditures were not affected by hurricane restoration costs, as costs were charged to the storm damage reserve, Tampa Electric paid an estimated $52 million of cash for hurricane restoration in 2004 with $20 million to be paid in 2005. In addition, the storms reduced base pretax revenues by an estimated $4.9 million, which by definition are not covered by the storm damage reserve. Tampa Electric has received FPSC approval for deferral of the $28 million until the company seeks alternative accounting treatment for the costs that exceed the reserve balance (see the **Regulation** section).

**Summary of Operating Results – Tampa Electric**

| *(millions)* | *2004* | *% Change* | *2003* | *% Change* | *2002* |
|---|---|---|---|---|---|
| Revenues | **$ 1,687.4** | 6.4 | $ 1,586.1 | 0.2 | $ 1,583.2 |
| Other operating expenses | **190.5** | -6.1 | 202.8 | -4.5 | 212.3 |
| Maintenance | **87.2** | -4.0 | 90.8 | -16.5 | 108.7 |
| Depreciation | **180.9** | -14.0 | 210.3 | 10.8 | 189.8 |
| Taxes, other than income | **120.8** | 7.3 | 112.6 | 0.3 | 112.3 |
| Non-fuel operating expenses | **579.4** | -6.0 | 616.5 | -1.1 | 623.1 |
| Fuel | **612.9** | 38.3 | 443.3 | 4.5 | 424.1 |
| Purchased power | **172.3** | -26.6 | 234.9 | -7.4 | 253.7 |
| Total fuel expense | **785.2** | 15.8 | 678.2 | 0.1 | 677.8 |
| Turbine valuation adjustment | **–** | – | 79.6 | – | – |
| Total operating expenses | **1,364.6** | -0.7 | 1,374.3 | 5.6 | 1,300.9 |
| Operating income | **$ 322.8** | 52.4 | $ 211.8 | -25.0 | $ 282.3 |
| AFUDC Equity | **$ 0.7** | -96.5 | $ 19.8 | -20.5 | $ 24.9 |
| Net income | **$ 146.0** | 47.6 | $ 98.9 | -42.4 | $ 171.8 |
| Turbine cancellation charges after-tax | **–** | – | 48.9 | – | – |
| Restructuring charges after-tax | **–** | – | 6.1 | – | 10.3 |
| Net income before charges | **$ 146.0** | -5.1 | $ 153.9 | -15.5 | $ 182.1 |

**Tampa Electric Operating Revenues**

Retail megawatt-hour sales rose 1.1% in 2004, primarily from increased residential and commercial sales driven by customer growth. Electricity sales to the lower margin industrial customers in the phosphate industry decreased 3.7% in 2004 after a 7.4% decrease in 2003. The 2004 decline in sales to phosphate customers was driven by natural reserve depletion and migration of mining operations out of Tampa Electric's service area. In 2004, following several years of low prices for phosphate fertilizers and high raw material costs, phosphate prices returned to levels that support normal production. In 2003, low prices contributed to temporary closures of phosphate production facilities during the year. Domestic phosphate consumption and prices are expected to remain relatively stable for the next several years with increased demand from China driving an improved export market. Tampa Electric's phosphate customers have indicated that, with the price improvement experienced in 2004, they expect production to remain stable in 2005. Base revenues from phosphate sales represented less than 3% of base revenues in 2004 and 2003. Non-phosphate industrial sales increased in 2004 and 2003, primarily reflecting continued economic growth in the area.

Base rates for all customers were unchanged in 2004. Fuel-related revenues increased in 2004 and 2003 under the FPSC-approved fuel adjustment clause due to the recovery of previous under recoveries of fuel expense in 2003 and 2002 and higher gas prices. Customer's rates under the fuel adjustment clause would increase in 2005 in accordance with the rates approved by the FPSC in November 2004, to reflect the higher cost of natural gas and increased usage of natural gas due to the completion of the Bayside repowering in January 2004. The customer fuel adjustment charge increase from higher fuel prices will, however, be more than offset by the approximately $15 million pretax disallowance of the recovery from customers of a portion of the waterborne solid fuel transportation costs, which are recovered through the fuel adjustment clause (see the **Regulation** section).

Sales to other utilities for resale declined in 2004, primarily as a result of lower capacity being available from coal-fired generating units due to the conversion of the coal-fired Gannon Station to natural gas. Incremental generation among the utilities in Florida is primarily natural gas-fired; therefore, the Bayside units compete with all other units burning the same fuel in the state. Sales to other utilities declined in 2003, primarily due to the lack of coal-fired generating unit availability as the Gannon units underwent the conversion to natural gas, and the Jan. 1, 2003 expiration of the Big Bend Station power sales agreement with Hardee Power Partners. Energy sales to other utilities are expected to remain stable in 2005.

Based on projected growth from continued population increases and business expansion, Tampa Electric expects weather-normalized average retail energy sales growth of more than 2.5% annually over the next five years, with combined energy sales growth in the residential and commercial sectors of 3% annually. Tampa Electric's forecasts indicate that summer retail peak demand growth is expected to average more than 100 megawatts per year for the next five years. These growth projections assume continued local area economic growth, normal weather and a continuation of the current energy market structure (see the **Investment Considerations** section).

The economy in Tampa Electric's service area continued to grow in 2004, aided by the region's relatively low labor rates, attractive cost of living and relatively affordable housing. The Tampa metropolitan area's non-farm employment grew 2.1% in 2004 due to a stronger local economy. Employment grew 1.2% in 2003 in spite of the U.S. economic slowdown in the first half of the year. The local Tampa area unemployment rate fell to 3.5% at year-end 2004, compared with 3.8% in December 2003, and 4.2% in December 2002. These rates are lower than the year-end 4.5% unemployment rate for the State of Florida and 5.4% for the nation. During the U.S. economic slowdown in 2002 and early 2003, the Tampa area, with its diverse service-based economy, did not experience the same drop in economic activities as those areas of the country with manufacturing-based economies and recovered sooner.

**Megawatt – Hour Sales**

| *(thousands)* | *2004* | *% Change* | *2003* | *% Change* | *2002* |
|---|---|---|---|---|---|
| Residential | **8,293** | 0.3 | 8,265 | 2.7 | 8,046 |
| Commercial | **5,988** | 2.2 | 5,860 | 0.5 | 5,832 |
| Industrial | **2,556** | -0.9 | 2,579 | -1.3 | 2,612 |
| Other | **1,600** | 4.0 | 1,538 | 7.2 | 1,435 |
| Total retail | **18,437** | 1.1 | 18,242 | 1.8 | 17,925 |
| Sales for resale | **664** | -3.9 | 691 | -36.3 | 1,084 |
| Total energy sold | **19,101** | 0.9 | 18,933 | -0.4 | 19,009 |
| Retail customers-thousands (average) | **619.5** | 2.4 | 604.9 | 2.5 | 590.2 |

**Tampa Electric Operating Expenses**

Total operating expense decreased slightly in 2004 as higher fuel costs due to increased use of natural gas largely offset lower non-fuel operating and maintenance expenses and lower purchased power costs. Non-fuel operating and maintenance expenses decreased from the lower manpower requirements and lower maintenance requirements of the natural gas-fired repowered Bayside Station compared to the coal-fired Gannon Station. Operating expenses were also reduced by the restructuring activities in 2002 and 2003, which reduced the number of employees 12% during the two-year period.

In 2003, total operating expenses, excluding the $79.6 million pretax charge for combustion turbine purchase cancellations, were almost unchanged from 2002 levels as lower non-fuel operations and maintenance expenses for power generation plants and lower purchased power expenses largely offset higher fuel costs from increased use of higher cost natural gas, higher depreciation and increased employee benefits costs.

After significant reductions in 2004, non-fuel operations and maintenance expenses are expected to increase at slightly above the rate of inflation in 2005 due to normal operating and maintenance expense growth and higher employee-related costs, such as pension expenses.

Depreciation expense decreased in 2004 due to the end of the accelerated depreciation in 2003 related to the retirement of the Gannon Station coal-fired assets, which more than offset the additional depreciation from the addition of Bayside Unit 2. (See the **Environmental Compliance** section.) Accelerated depreciation of the Gannon Station coal-fired assets was $36.6 million pretax in 2003. Depreciation expense is projected to increase in 2005, due to normal plant additions to serve the growing customer base and maintain system reliability.

Fuel costs increased 38.3% in 2004 after a 4.5% increase in 2003, primarily due to increased use of natural gas at the Bayside Power Station and higher natural gas prices. On a per million Btu basis, natural gas consumption increased 75% in 2004 while coal usage decreased 16.7%, which is in line with the increased generation from natural gas and decreased generation from coal as a result of the Bayside repowering. Fuel prices increased across the board in 2004, with increases per million Btu ranging from 5.6% for coal to 10.7% for natural gas. The delivered cost of natural gas has increased since 2002 when prices were $5.86 per million Btu to the 2004 average price of $7.14 per million Btu. Coal prices have also increased during that period from a delivered cost of $1.93 per million Btu in 2002 to $2.14 per million Btu in 2004. Coal and natural gas prices are expected to stay near the current levels due to the current world supply and demand situation, general economic conditions and the current high price of oil.

On a total energy supply basis, Tampa Electric generation accounted for 94.9%, 88.2% and 87.2% of the total retail energy sales in 2004, 2003 and 2002, respectively. The percentage increased due to the increased reliability and availability of the Bayside Station compared to the older Gannon Station.

Prior to 2003, nearly all of Tampa Electric's generation was from coal. Starting in April 2003, the mix started to shift, with increased use of natural gas at Bayside. Nevertheless, coal is expected to continue to be more than half of Tampa Electric's fuel mix due to the base load units at Big Bend and the coal gasification unit, Polk Unit One.

The amount of power purchased by Tampa Electric to serve its customers decreased in 2004 following a decrease in 2003, primarily due to the operations of Bayside. Purchased power is expected to decline again in 2005, due to the operation of Bayside Station and coal unit availability.

## *Peoples Gas System*

**Summary of Operating Results**

Peoples Gas (PGS) net income was $27.7 million in 2004, compared to $24.5 million in 2003. Non-GAAP results in 2004 were $28.1 million, excluding a $0.4 million after-tax restructuring charge, compared to non-GAAP results of $27.1 million in 2003, which exclude a $2.6 million after-tax restructuring charge. Results in 2004 reflect 5.3% customer growth partially offset by higher operating expenses. Results in 2003 reflect 5.2% customer growth and a $12 million base revenue increase effective in January 2003.

Historically, the natural gas market in Florida has been underserved with the lowest market penetration in the southeastern U.S. In 2003, natural gas had a market penetration rate of 9% compared to the next lowest state in the southeast, North Carolina, with 29%. PGS has targeted residential customer growth through agreements with builders in new residential communities throughout Florida, which have significantly higher expected average annual usage per-household than the current average.

In 2004, residential and commercial therm sales increased through customer growth. Usage per customer decreased compared to 2003 due to milder winter weather. In 2003, residential and commercial therm sales increased from customer growth of over 5%, and colder than normal early winter weather. Volumes transported for power generation customers declined again in 2004 after declining in 2003. The high gas prices experienced in 2003 persisted throughout 2004, spiking to near record levels in the fall of 2004 when oil prices rose above $50 per barrel. While the higher cost of gas has had a negative impact on sales to larger interruptible and power generation customers, especially in the second half of 2003 and into the first half of 2004, most of those who could switch fuels had already done so by mid-year 2004. Many of these customers have the ability to switch to alternative fuels or to alter consumption patterns in response to rising natural gas prices. Because these are lower-margin sales, the decrease has not significantly affected PGS results.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a Purchased Gas Adjustment (PGA) approved by the FPSC annually.

**Summary of Operating Results**

| (millions) | 2004 | % Change | 2003 | % Change | 2002 |
|---|---|---|---|---|---|
| Revenues | $ 417.2 | 2.1 | $ 408.4 | 28.4 | $ 318.1 |
| Cost of gas sold | 226.2 | 1.0 | 224.0 | 50.3 | 149.0 |
| Operating expenses | 131.1 | 0.8 | 130.0 | 12.5 | 115.6 |
| Operating income | 59.9 | 10.1 | 54.4 | 1.7 | 53.5 |
| Net income | 27.7 | 13.1 | 24.5 | 1.2 | 24.2 |
| Restructuring charges | 0.4 | – | 2.6 | – | – |
| Net income before charges | $ 28.1 | 3.7 | $ 27.1 | 12.0 | $ 24.2 |
| Therms sold - by customer segment | | | | | |
| Residential | 65.8 | 2.5 | 64.2 | 6.6 | 60.2 |
| Commercial | 368.1 | 3.7 | 354.8 | 8.3 | 327.6 |
| Industrial | 399.5 | -1.7 | 406.3 | -4.1 | 423.8 |
| Power generation | 291.6 | -19.8 | 363.7 | -26.2 | 492.6 |
| Total | 1,125.0 | -5.4 | 1,189.0 | -8.8 | 1,304.2 |
| Therms sold - by sales type | | | | | |
| System supply | 326.4 | -3.2 | 337.3 | 1.4 | 332.5 |
| Transportation | 798.6 | -6.2 | 851.7 | -12.3 | 971.7 |
| Total | 1,125.0 | -5.4 | 1,189.0 | -8.8 | 1,304.2 |
| Customers (thousands) – average | 307.4 | 5.3 | 291.9 | 5.2 | 277.5 |

In Florida, natural gas service is unbundled for any non-residential customers that elect this option, affording these customers the opportunity to purchase gas from any provider. The net result of this unbundling is a shift from bundled transportation and commodity sales to transportation sales. Because the commodity portion of bundled sales is included in operating revenues at the cost of the gas on a pass-through basis, there is no net financial impact to the company when a customer shifts to transportation-only sales. PGS markets its unbundled gas delivery services to these customers through its "NaturalChoice" program. At year end 2004, 11,100 of PGS' 29,000 non-residential customers had elected to take service under this program.

Operations and maintenance expenses decreased in 2004, compared to higher than normal operations and maintenance expenses in 2003 that included higher employee-related costs, including restructuring costs. Depreciation expense increased in both years, in line with the capital expenditures made over the past several years to expand the system.

In December 2002, the FPSC authorized PGS to increase annual base revenues by $12.05 million. The new rates allow for a return on equity range of 10.25 to 12.25% with an 11.25% midpoint, which is the same as its previously allowed return on equity, and a capital structure of 57.4% equity. The increase went into effect on Jan. 16, 2003 (see the **Regulation** section).

In May 2002, Gulfstream Natural Gas Pipeline initiated service. This interstate pipeline starts in Mobile Bay, Alabama, crosses the Gulf of Mexico and comes ashore in Florida just south of Tampa. Gulfstream is the first new pipeline serving peninsular Florida since 1959. This pipeline increased gas transportation capacity into Florida by 50%. PGS entered into a service agreement for capacity in 2002, for which the transportation volumes increased in 2003 and again in 2004. The addition of the Gulfstream pipeline enhances reliability of service and helps to meet the capacity needs for PGS' growing customer base.

Since its acquisition by TECO Energy in 1997, PGS has expanded its gas distribution system through system extensions into areas of Florida not previously served by natural gas, such as the lower southwest coast in the high-growth Ft. Myers and Naples areas and the northeast coast in the Jacksonville area. PGS' expansion strategy for the next several years is to take advantage of the significant capital investments in main pipeline expansions made over the past five years and connect customers to that existing infrastructure. PGS expects increases in sales volumes and corresponding revenues in 2005 and continued customer additions and related revenues from its build-out efforts throughout the state of Florida, assuming continued local economic growth, normal weather and other factors (see the **Investment Considerations** section).

## *TECO Coal*

TECO Coal's 2004 net income was $61.3 million, compared to $77.1 million in 2003. Non-GAAP results in 2004 were $54.3 million, excluding a $7.0 million benefit to income taxes from a true-up of Section 29 tax credits, compared to $84.1 million in 2003, which excluded a $7.0 million negative adjustment due to unrecognizable Section 29 tax credits, discussed below. Sales in 2004 were 9.1 million tons, compared to 9.2 million tons in 2003. These lower results reflect an increase of third-party ownership of the synthetic fuel production facilities to more than 90% and 17% higher production costs. The increased production costs were primarily due to increased diesel fuel prices, higher prices for steel products and higher contract miner costs. The higher production costs were partially offset by average prices for coal sales which were more than 12% higher than 2003.

The third-party ownership structure of the synthetic fuel production facilities reduces the net income per ton from the production of synthetic fuel but increases cash generation per ton. TECO Coal recorded no Section 29 tax credits for 2004 production associated with its remaining synthetic fuel ownership interest because of TECO Energy's anticipated tax position in 2004, which was driven by tax losses incurred upon the disposition of merchant power plants. The 2004 $7.0 million positive true-up to income taxes was related to Section 29 tax credits that, due to projected limitations on taxable income, were reserved for in 2003 but were found to be recognizable in 2004 upon finalizing the 2003 tax return.

In 2003, net income was $77.1 million, compared to $76.4 million in 2002. Total coal sales were almost 9.2 million tons in 2003. These results were driven by higher volumes of synthetic fuel production and sales and the sale of a 49.5% membership interest in the synthetic fuel production facilities, partially offset by lower volumes and prices for conventional coals and higher mining costs due to the use of marginal and waste coals for the production of synthetic fuel.

In 2004, synthetic fuel production and sales increased to 6.3 million tons from 5.8 million tons and 3.8 million tons in 2003 and 2002, respectively. Included in TECO Coal's results are the approximately $1.00 to $2.00 per ton higher mining costs associated with the use of marginal coals, which would be otherwise uneconomical to mine, in the production of synthetic fuel. In addition to the 49.5% membership sold in April of 2003, in May 2004, TECO Coal's subsidiary, TECO Synfuel Holdings, LLC, sold an additional 40.5% of its membership interest to third parties, along with associated percentage rights to benefits in the business which adjust from time to time. Allocation of the benefits varied in 2004 such that more than 90% of the benefits were to third parties. Under these transactions, TECO Coal is paid to provide feedstock, operate the synthetic fuel production facilities and sell the output while the purchasers have the risks and rewards of ownership, including being allocated 90% of the tax credits and operating costs. In addition to receiving reimbursement of the operating costs of the 90% share (minority interest credit), TECO Coal recognizes a gain on the sale of the facilities for each ton of synthetic fuel sold. The cash benefit in 2004 includes $84.5 million of gain from this sale, net of $34.6 million escrowed, and $76.1 million of minority interest credit.

In 2005, total coal sales and synthetic fuel production are expected to be about 9.2 million tons and 6.3 million tons, respectively, with virtually all planned production sold forward under contracts of varying terms. Due to expected variations in the allocation of benefits to the third-party owners, more than 90% of the benefits are expected to be sold in 2005. Contracted coal prices for 2005 are significantly higher than for 2004 and 2003. Average coal prices for all products are expected to be 40% higher than the $33 per ton realized in 2004. Production costs are expected to increase more than 10% in 2005, driven by continued higher contract miner costs, higher royalty and severance fees that are a function of coal prices, and higher transportation costs.

TECO Coal sells almost all of its annual production under contracts that are finalized late in the previous year or early in the current year. It did not realize the high reported spot prices for the majority of its production in 2004 because of the timing of its contract renewals. Due to this contracting strategy, TECO Coal is less affected by the rapid price changes, both upward and downward, than those companies that sell a higher percentage in the spot markets.

Higher prices for competing fuels, increased demand for metallurgical coal worldwide, better balance in supply and demand, lower producer and consumer inventories and consolidation in the mining industry have contributed to higher prices recently. In addition, changes that have occurred over the past several years, including industry consolidation, longer environmental permitting time for new mines, fewer skilled coal miners, gradual depletion of high-quality Central Appalachian reserves and increased international demand for U.S. coal, have allowed producers to contract production for 2005 and 2006 at prices much higher than 2004 levels. Current indications within the coal industry are that prices may decline slightly after 2006 but remain well above 2004 levels.

In January 2000, TECO Coal purchased synthetic fuel facilities from Headwaters Technologies, Inc. The facilities were relocated to the company's Premier Elkhorn and Clintwood Elkhorn mines in Kentucky and were producing by the second quarter of 2000. These facilities produce synthetic fuel from coal, coal fines and waste coal using a technology licensed from Headwaters. The facilities were subsequently sited at all three of TECO Coal's complexes.

TECO Coal has received private letter rulings (PLRs) from the Internal Revenue Service (IRS) regarding the qualification of synthetic fuel production from its facilities. The PLRs confirm that the facilities are located appropriately and produce a qualified fuel eligible for Section 29 tax credits, which are available for the production of such non-conventional fuels through 2007. In June 2003, the IRS suspended issuance of PLRs to taxpayers seeking certainty regarding the use of the Section 29 tax credits for the production of synthetic fuel from coal. The suspension was due to questions raised within the IRS regarding the validity of the production of a significant chemical change in the production of synthetic fuel as required under Section 29. In October 2003, the IRS concluded its review and resumed issuing PLRs. TECO Coal received a PLR from the IRS on Oct. 31, 2003 that affirmed previous rulings after the ownership change and confirmed that the synthetic fuel produced by TECO Coal is eligible for Section 29 tax credits and that its test procedures are in compliance with the requirements of the IRS. In the course of conducting its audit of TECO Energy's consolidated year 2000 tax return, the first year that TECO Coal produced synthetic fuel, the IRS reviewed the company's compliance with the requirements for Section 29 tax credits and completed the audit with no adjustments required. The return closed by statute in September 2004.

The economics of the sale of the ownership interests in the synthetic fuel production facilities are reasonably constant as they are determined by the level of the tax credits and not the price received from the sale of output. The Section 29 tax credit is determined annually and is estimated to be $1.12 per million Btu for 2004 and was $1.10 per million Btu in 2003 and $1.09 per million Btu in 2002. This rate escalates at a rate slightly less than inflation, but could be limited by domestic oil prices. For 2004, average annual domestic oil prices, as measured by a U.S. Department of Energy (DOE) index, would have had to exceeded $51 per barrel for this limitation to have been effective. The DOE index is based on the "Domestic First Purchase Prices," not the New York Mercantile Exchange (NYMEX) quoted oil futures prices, and typically averages $3.00 per barrel less than the NYMEX price. If the oil price limitation is reached, the level of the tax credits starts to decline. In 2004, it was estimated that the tax credit would have been eliminated at an average oil price of $64 per barrel. The oil price range for 2005 is expected to range from $52 to $65 per barrel, which is the equivalent of $55 to $68 per barrel on NYMEX. In late 2004, TECO Coal hedged approximately 35% of its exposure to higher oil prices on its expected synthetic fuel production (see the **Market Risk** section).

Section 29 tax credits will expire Dec. 31, 2007, and we cannot predict if these tax credits will be extended or renewed in their current form. Following the expiration of the tax credits, we expect both net income and cash flow to decline due to the loss of the benefits from the sale of the third-party membership interests. In 2008, TECO Coal expects to no longer produce synthetic fuel, but it expects to produce conventional coal at levels approximately the same as current total production (approximately 9 million tons). When production of synthetic fuel ends, TECO Coal will stop mining the high-cost-of production coals currently being mined for use in the production of synthetic fuel and will stop operating the synthetic fuel production equipment, which are expected to reduce production costs. At that time, the earnings and cash flow from TECO Coal will be dependent on the selling price of coal in 2008 and its ability to manage production costs.

The significant factor that could influence TECO Coal's results in 2005 is the higher expected costs of production. Longer-term factors that could influence results include weather, general economic conditions, commodity price changes, the level of domestic oil prices, and the ability to use Section 29 tax credits, which are scheduled to expire Dec. 31, 2007 and could be impacted earlier by administrative actions of the IRS, the U.S. Treasury or changes in laws, regulations or administration. (See the **Investment Considerations** section.)

## *TECO Transport*

TECO Transport's 2004 net income was $10.2 million, compared to $15.3 million in 2003. Non-GAAP results in 2004 were $11.9 million excluding a $1.1 million after-tax restructuring charge and a $0.6 million after-tax valuation adjustment on ocean-going equipment, compared to non-GAAP results of $16.3 million in 2003, which excluded a $1.0 million after-tax restructuring charge and a $0.8 million after-tax charge for a change in accounting principle. These results were driven by lower tonnage transported for Tampa Electric due to the repowering of the formerly coal-fired Gannon Station to the natural gas-fired Bayside Station, weak market conditions in the first half of 2004 for the river and terminal business segments, higher fuel costs and unusual operating conditions, including a five-day closing of the Mississippi River and the impact on operations from the four hurricanes. The hurricanes in August and September disrupted river and ocean movements and caused the terminal in Louisiana to halt operations. Estimated lost revenues and direct costs due to the hurricanes reduced TECO Transport's pretax results by $3.8 million.

Net income in 2003 was $15.3 million, compared to $21.0 million in 2002. Non-GAAP results in 2003 were $16.3 million, excluding a $1.0 million after-tax restructuring charge, compared with $21.0 million in 2002. The decrease was primarily due to lower tonnage transported for Tampa Electric due to the conversion of the Gannon Station from coal to the natural gas-fired Bayside Station, continued weak results from the river transportation and terminal businesses due to lower northbound shipments, a very competitive pricing environment, and higher labor and repair costs. Results for 2003 also included a $3.5 million after-tax gain associated with the disposition of ocean-going assets no longer used by TECO Ocean Shipping and scrap river barges at TECO Barge Line.

TECO Transport's operating companies were impacted by lower tonnage transported for Tampa Electric in 2004 and 2003 when coal shipments were reduced approximately 1 million tons annually in each of these years. Total annual tonnage handled for Tampa Electric has now stabilized and is expected to average about 5 million tons annually, compared to more than 7 million tons annually prior to the completion of the repowering of Bayside. TECO Transport replaced a portion of this tonnage with increased third-party business and is continuing to seek other new replacement business.

The phosphate fertilizer industry, an important business segment for TECO Ocean Shipping, had stable prices and production in 2004 following several years of low demand and prices. TECO Ocean Shipping expects 2005 phosphate shipments to be at levels similar to 2004 levels.

The river barge industry is now experiencing a better balance in supply and demand for river barge services due to improvements in the U.S. economy and the scrapping of a large number of obsolete river barges by operators throughout the country. A number of river barges which were built in the 1980's, driven mainly by tax incentives, are now at the end of their useful lives and are being scrapped. The increased rate of barge retirements and the high cost of steel, which has made construction of replacement barges uneconomical, has reduced the supply of barges at a time of increasing demand. The improved U.S. economy, more normal shipping patterns and the reduced supply of barges is expected to improve pricing for river barge services in 2005.

Driven by strong demand for shipments of raw materials to China and India, imports and exports through the Port of New Orleans on the Mississippi River, which impact the river and terminal businesses, were below normal from the second half of 2003 through the middle of 2004. In the second half of 2004, more raw materials, both imports and exports, flowed through the Port of New Orleans. As a result, the terminal and river businesses experienced increased movements of export coal and other products. The river business also benefited from increased southbound shipments of grain products in 2004, with improved pricing during the fall grain shipping season.

The demand for non-U.S. flag ocean-going vessels to meet the demand for shipments to China caused rates for these vessels, as measured by the Baltic Dry Index, to climb significantly starting in the second half of 2003 and reach a record high in November 2004. As a U.S. flag carrier, TECO Transport does not benefit directly from these increased rates since it does not compete against non-U.S. flag vessels in these markets. However, the high international shipping rates do create additional opportunities for spot cargo shipments for TECO Transport's ocean-going vessels. Although prices as measured by the Baltic Dry Index varied considerably in 2004, the overall trend has been for higher prices, which is expected to continue.

TECO Transport expects improved results in 2005 from better pricing for river barge transportation, increased volume through the terminal, higher rates on those contracts with fuel adjustment clauses, and continued diversification into new markets and cargoes. Future growth at TECO Transport is dependent upon improved pricing, higher asset utilization, and potential asset additions at both the river and ocean-going businesses. Significant factors that could influence results include weather, bulk commodity prices, fuel prices, domestic and international economic conditions, and import and export patterns (see the **Investment Considerations** section).

## *Other Unregulated Companies*

**Other Unregulated Companies**

| *Project* | *Location* | *Size MW* | *Ownership Interest* | *Net Size MW* | *In Service/ Participation Date* |
|---|---|---|---|---|---|
| Alborada Power Station | Guatemala | 78 | 96% | 75 | 9/95 |
| Empresa Eléctrica de Guatemala S.A.(EEGSA) (a distribution utility) | Guatemala | | 24% | | 9/98 |
| San José Power Station | Guatemala | 120 | 100% | 120 | 1/00 |
| Total non-merchant | | 198 | | 195 | |

Our other unregulated companies consist primarily of the non-merchant power plants operating in Guatemala and the ownership interest in Guatemala's largest distribution utility, EEGSA. The San José and Alborada power stations in Guatemala both have long-term power sales contracts. The other unregulated companies also included BCH Mechanical, which was sold in January 2005, and its results are included in discontinued operations for all periods.

The other unregulated companies net income in 2004 was $12.1 million, compared to $23.2 million in 2003. Non-GAAP results in 2004 were $40.1 million, excluding the following after-tax charges and gains: $12.8 million associated with the write-off of unused steam turbines; a $6.7 million charge associated with the extinguishment of debt in the non-recourse financing of the San José Power Station; a $17.4 million provision for income taxes due to the repatriation of cash from Guatemala following the refinancing; a $3.4 million valuation adjustment at TECO Solutions; and a $12.0 million gain on the sale of our interest in the propane business. Non-GAAP results in 2003 were $24.3 million. These results were driven by continued good operating performance at the Guatemalan generating facilities, higher energy sales at EEGSA and a $5.6 million benefit from reducing previously deferred income taxes due to a change in Guatemalan tax law. In addition, an electric rate increase, approved in late 2003, contributed to significantly improved results at EEGSA in 2004.

Net income for the other unregulated companies in 2003 was $23.2 million, compared to $27.0 million in 2002. Non-GAAP results in 2003 were $24.3 million excluding the following after-tax charges and gains: $28.5 million of charges for turbine valuation adjustments and purchase cancellations; a $9.0 million write-off of non-merchant project development costs; a $3.6 million corporate restructuring charge; and a $42.9 million benefit from the gain on the sale and the net income from operations from the Hardee Power Station, which was sold in October 2003 (see the **Results Summary** section).

Results in 2003 reflected higher net income from EEGSA from increased energy sales at higher prices and favorable currency exchange rates, more than offset by unfavorable tax adjustments on the Guatemalan assets and increased maintenance costs for scheduled maintenance at the San José Power Station.

In November 2003, we announced the sale of our interest in TECO Propane Ventures (TPV) which closed in January 2004. TPV held the company's propane business investment. The sale, which was part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage, was announced in November 2003. Our portion of the sale generated $53.1 million of cash and a $12.0 million after-tax book gain in 2004.

## *TWG-Merchant*

In 1999, we announced that a component of our strategy was to expand our presence in the domestic independent energy industry (see the **Strategy and Outlook** section). Our decision to invest in this industry was based on the outlook at that time for the energy markets beyond 2001, based on the expectation that there would be wide-spread deregulation of these markets. In the face of many events since that time that have diminished the prospects for the profitability of our investments in unregulated independent power plants, we have rethought our independent power strategy. As a result, in 2003 we announced that our strategy going forward was to focus on our Florida utilities and our profitable unregulated businesses and to reduce our exposure to the merchant power markets. Since that time we have taken a number of steps to implement that strategy, including the sale of merchant power assets and making the decision that we would probably not complete the Dell and McAdams power plants. During 2004, we announced our decision to transfer the ownership of the Union and Gila River projects back to the lenders; we sold our interests in Texas Independent Energy, the partnership that owned the Odessa and Guadalupe plants in Texas, and the Frontera Power Station in Texas; and announced an agreement to sell the Commonwealth Chesapeake Power Station.

With the sales completed in 2004, the only operating power plant remaining in the TWG-Merchant segment is the Commonwealth Chesapeake Power Station. Following completion of the announced sale of Commonwealth Chesapeake, now expected near the end of the first quarter of 2005, its results will be accounted for as discontinued operations. Expenses related to the unfinished Dell and McAdams power stations and TECO EnergySource, Inc. (TES), the energy marketing operation for the merchant plants, also will continue to be reported in the TWG-Merchant segment unless those assets are disposed of or TES ceases operation. As of year-end 2003, the Union and Gila River power plants were considered "Held for Sale" and were accounted for in discontinued operations (described further below).

TWG-Merchant reported a loss in 2004 of $583.0 million, compared to a loss of $99.8 million in 2003. On a non-GAAP basis, the loss in 2004 was $55.3 million, compared to a non-GAAP loss of $53.5 million in 2003. The non-GAAP results in 2004 exclude after-tax charges for the $381.7 million valuation adjustment for Dell and McAdams; the $99.0 million valuation adjustment for the TIE projects, which were sold in July; the $51.3 million valuation adjustment for the Commonwealth Chesapeake Power Station, for which we have announced an agreement to sell the plant in 2005; and a positive $4.3 million true-up to the reserve taken in 2003 for the TMDP arbitration award, which was settled at a lower cost. The 2003 non-GAAP results exclude after-tax charges of $26.7 million for a TMDP arbitration award, $16.4 million for the write-off of goodwill associated with the Commonwealth Chesapeake Power Station, and $0.3 million charge for corporate restructuring.

The 2004 results reflect the allocated interest expense and carrying costs associated with the unfinished Dell and McAdams plants; the operating losses at the TIE projects for the first six months of 2004 due to continued weak power prices in Texas; and weak power prices in Virginia, primarily due to weather and fuel prices affecting results at the Commonwealth Chesapeake Power Station, which were partially offset by an insurance settlement on previously incurred repair costs. Results in 2003 reflected a full year of operating losses at the TIE projects; the carrying costs associated with the Dell and McAdams plants, primarily due to the cessation of interest capitalization; and weak results at the Commonwealth Chesapeake Power Station, which were impacted by the mild and wet summer weather in the region served by the plant that reduced peak summer load.

**Union and Gila River Power Stations**

In October 2003, we announced that we would put little if any additional cash into the merchant generation portfolio, and in February 2004, we announced our decision to exit from our ownership of the Union and Gila River projects and to cease further funding of these plants. Leading up to that decision, we, as the equity investor, and the subsidiary project companies that own the two large plants negotiated with the lending group that provided the non-recourse project financing for these projects regarding the terms of a sale and transfer of ownership of the plants to these lenders.

These negotiations resulted first in a non-binding letter of intent containing a binding settlement agreement entered into on Feb. 5, 2004, supplemented by a term sheet executed in July 2004, and an agreem ent in October 2004 with the steering committee of the lending group on the material terms and forms of definitive agreements for the consensual sale and transfer of the plants to the lending group, subject to lender approval.

The negotiated arrangements included (i) the terms of the proposed sale and transfer; (ii) the treatment of $66 million of letters of credit posted by us under the construction undertakings related to the projects, with $35 million drawn in February 2004 for the benefit of the project companies and the remaining $31 million cancelled and returned to us; and (iii) our payment of $30 million to the lending group upon completion of the transfer of the plants in exchange for full releases by the lenders and project entities of TECO Energy and its related entities of all previous financial obligations (except for warranty items identified prior to the expiration of the original warranty period).

The contemplated consensual transfer required 100% lender approval to implement. During the steering committee's process of seeking approval by all lenders, certain issues regarding the post-transaction structure were raised by two of the 40-member lender group and 100% vote could not be achieved. As a result, an alternative of a pre-negotiated reorganization in bankruptcy was pursued.

Pursuant to this alternative, on Jan. 24, 2005, 95% in number and 90% in aggregate principal amount of the Union and Gila River project lenders entered into a Master Settlement and Restructuring Support Agreement (the "Master Settlement Agreement"), in which they agreed to vote their respective claims in favor of the pre-negotiated Joint Plan of Reorganization (the "Joint Plan"), and on Jan. 26, 2005, the Union and Gila River project entities filed Chapter 11 cases which included the Joint Plan in the U.S. Bankruptcy Court for the District of Arizona. The terms of the Joint Plan are substantially the same as the terms of the transaction that were previously announced as part of the proposed consensual sale and transfer of the projects to the lending group.

For the Joint Plan to be confirmed, it must be approved by an affirmative vote of creditors holding more than 50% in number of obligations and more than two-thirds of the dollar amount of such obligations in each impaired class. There are only two impaired classes of claims that are entitled to vote on the Joint Plan. Those classes are the project lenders, who hold secured claims, and holders of unsecured claims, which include the project lenders' deficiency claims, our $190 million claims and a nominal amount of other claims. We also consented to the Joint Plan. Our claim consists of all of the payments we made to complete the plants and meet warranty and other unfulfilled obligations of the contractor pursuant to the undertakings as a result of the bankruptcy of Enron, the contractor's parent. This amount will be reduced by the $35.6 million we have recovered through the sale of the Enron bankruptcy claims and reaching a settlement with Enron, scheduled for approval by the court in March 2005. The amounts of these claims were included in the impairment charges related to the two plants taken at year-end in 2003. First day motions were heard on Jan. 27, 2005 and a critical path scheduling order has been issued, setting Apr. 19 and 20, 2005 as the date for a confirmation hearing on the Joint Plan, with any objections required by Apr. 2, 2005. FERC approval of the transfer of the facilities to the bank lending group was received on Jan. 24, 2005.

In addition to the high approval rate for the Master Settlement Agreement, 100% of the project lenders approved the Master Release Agreement (the "Release") providing for the release of all claims against us and the project entities, and vice versa, which is part of the Joint Plan. The Release becomes effective upon the transfer of the projects at such time as the Joint Plan is confirmed and the previously described payment by us of $30 million is made.

Although we expect this matter to be resolved as contemplated by the Joint Plan, should this not occur, the parties have reserved their rights against each other, and the lending group could seek to exercise remedies against the project companies due to defaults in connection with the non-recourse project debt and related undertakings, including accelerating the non-recourse project debt and foreclosing on the project collateral, subject to any defenses that may exist.

**Accounting Treatment**

Based on the anticipated schedule for completion of the pre-negotiated Chapter 11 cases for the projects, we are maintaining our short-term view of these projects. Our consolidated financial results include the 2004 results from operations and the 2003 after-tax asset impairment of $762 million for previous investments to reflect adjustments to the value of the subsidiaries that own the interests in the two plants. The 2003 after-tax impairment charges included the asset valuation adjustments which resulted in the write-off of the full investment in the facilities, costs related to the accelerated impact of the change in hedge accounting for interest rate swaps and a related valuation allowance for certain state tax benefits. The Union and Gila River power stations are considered "Held for Sale" and are included in discontinued operations for income statement purposes, and the assets and liabilities are separately stated as "Held for Sale" on the balance sheet. This accounting treatment could be affected in future periods, depending on the ultimate disposition of our ownership in the plants.

## *Liquidity, Capital Resources*

Our consolidated cash and cash equivalents, excluding all restricted cash, totaled $96.7 million at Dec. 31, 2004. Restricted cash of $57.1 million included $50.0 million, held in escrow until the end of 2007, related to the sale of a 49.5% membership interest in the synthetic coal production facilities. Cash at Dec. 31, 2004 excluded the San José and Alborada power stations' unrestricted cash balances of $39.8 million and restricted cash of $8.1 million, as these companies were deconsolidated due to the adoption of FIN 46R, *Consolidation of Variable Interest Entities*, effective Jan. 1, 2004.

In addition, at Dec. 31, 2004 our aggregate availability under bank credit facilities was $332.6 million, net of letters of credit of $27.4 million outstanding under these facilities and $115.0 million drawn on the Tampa Electric credit facility. At Dec. 31, 2004, total liquidity, cash plus credit facilities, was $469.1 million, including $161.3 million at Tampa Electric which consisted of $160 million of undrawn credit facilities and $1.3 million of cash, and $39.8 million of unrestricted cash associated with the deconsolidated Alborada and San José power stations.

In 2004, we met our cash needs largely from internal sources and asset sales. Cash from operations was $140 million. Other sources of cash, included $161 million of proceeds from the sale of more than 90% membership interest in TECO Coal's synthetic fuel production facilities to third-party owners net of escrowed cash, and $230 million of proceeds from the sales of interests in various businesses, including the Frontera Power Station, the Hamakua Power Station, the propane business and Prior Energy. Cash used in financing activities included payment of common dividends of $145 million and the repayment of long-term debt of $225 million, including $75 million of first mortgage bonds at Tampa Electric and $123 million of TECO Capital Trust II trust preferred securities in 2004. Capital expenditures in 2004 were $272 million.

In 2003, we met our cash needs with a mix of externally and internally generated funds. Cash from operations was $311 million, net proceeds from asset sales were $250 million and proceeds from the sale of debt and equity were $792 million. Cash was used to fund $624 million of capital investments, debt repayments of $526 million, net reduction of short term debt of $323 million and dividends to common shareholders of $165 million.

**Cash from Operations**

In 2004, our consolidated cash flow from operations of $139.6 million was driven by a number of factors, including hurricane restoration costs at Tampa Electric; the accounting for the sale of interests in the synthetic fuel production facilities at TECO Coal, the costs of which are included in cash from operations while the benefits of which are recorded in financing and investing activities, as described more fully below; the deconsolidation of the San José and Alborada power stations; the payment of the TMDP arbitration award, and; the cash operating results of the Union and Gila River power stations. Because the substantial charges for asset impairments were non-cash in nature, they did not affect cash from operations.

Following an initial 49.5% membership interest sold in 2003, in May 2004, TECO Coal sold an additional 40.5% membership interest in its synthetic fuel production facilities, bringing the total third-party membership interest sold to 90%. Cash flow from operations includes the operating losses of approximately $10.00 per ton (pretax) associated with the production of synthetic fuel, while the cash benefits from the sale of the synthetic fuel production facilities of approximately $32 per ton (pretax) are included in the investing and financing activities on the Consolidated Statement of Cash Flows. Investing activity includes cash from the gain on the sale of the synthetic fuel facilities. The company expects to record a gain associated with the sale of the assets through the life of the contract. The cash paid by the owner for its portion of the operating loss from the production of synthetic fuel is included in Financing Activities as a minority interest.

Cash from operations in 2005 is expected to reflect improved net income from the operating companies, lower cash payments of income taxes, collection by Tampa Electric of the under-recovered fuel expense from 2004, lower interest expense due to the retirement of almost $400 million of trust preferred debt associated with the 9.5% equity security units (see the **Financing Activity** section), and the remaining payments by Tampa Electric for the 2004 hurricane restoration efforts. Cash operating losses from the Union and Gila River power stations will affect consolidated cash from operations until the plants are transferred to the lenders but will not affect consolidated cash since investing activities will include an offsetting source of cash, which is currently restricted cash at the project companies.

We had not made a contribution to our defined benefit pension plan since the 1995 plan year because investment returns had been more than sufficient to cover liability growth. Negative stock market returns in 2001 and 2002 reduced the overfunding of the plan to the point where the plan was not completely funded. In 2004, we made a $14.2 million contribution to our defined benefit pension plan and expect to make a cash contribution of a similar amount in 2005 (see **Note 5** to the **Consolidated Financial Statements**).

**Cash from Investing Activities**

Cash from investing activities of $90 million in 2004 included, among other items, capital investments totaling $272 million and net asset sale proceeds of $315 million. Asset sales included $141 million from the sale of the Frontera and Hamakua power stations, $83 million from the sale of the TECO Solutions companies including Prior Energy and our interest in the propane business, and installments of $84 million (net of $35 million of escrowed funds) from the sale of the more than 90% membership interest in TECO Coal's synthetic fuel facilities.

Following the completion of a substantial capital investment program in 2003, both for TWG's merchant power facilities and for Tampa Electric's Bayside Power Station, capital spending in 2004 was at the maintenance levels required to support customer growth and system safety and reliability at Tampa Electric and Peoples Gas and maintenance levels at TECO Coal and TECO Transport for normal equipment replacements and capitalized maintenance expenditures. For the next several years, we expect capital spending at similar levels supporting customer growth, safety and reliability, and renewal and replacement of capital in addition to the required capital expenditures for committed environmental projects at Tampa Electric (see **Capital Investments** section).

**Cash from Financing Activities**

Net cash used in financing activities of $242 million in 2004 included $75 million of debt repayments of Tampa Electric first mortgage bonds, scheduled principal payments of Peoples Gas debt, and the retirement of $123 million of trust preferred debt securities (see the **Financing Activity** section). We also paid $145 million in common stock dividends, equity contract adjustment payments totaling $35 million, and cash payments associated with the early settlement of our equity security units. Short-term debt increased $78 million due to draws under the Tampa Electric credit facilities. We received $76 million for reimbursement of the operating losses of TECO Coal's synthetic fuel production facilities in the form of minority interest payments from the third-party owners.

In January 2005, we received $180 million and issued 6.85 million shares of common stock in the final settlement of our equity security units (see the **Financing Activity** section).

We have no significant corporate debt maturities until 2007; however, consistent with our stated goal to improve our financial position, we may from time to time use available cash to purchase debt in the open market, in privately negotiated transactions, by exercise of optional redemption rights or otherwise. We do not expect to raise capital from external sources in 2005, except for short-term borrowing under Tampa Electric's credit facilities.

**Liquidity Outlook**

With the completion of our major construction programs in 2003 combined with our reduced exposure to the merchant power markets, our current and future liquidity needs are lower than in previous years. We target consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of $450 million, comprised of $250 million for Tampa Electric Company and $200 million for TECO Energy. At Dec. 31, 2004 our consolidated liquidity was $469 million.

In January 2005, Tampa Electric entered into a $150 million accounts receivable securitized borrowing facility. With the addition of this facility, Tampa Electric has credit facilities totaling $425 million. It expects to draw upon its facilities for normal working capital fluctuations and to support its expected environmental capital spending over the next several years and otherwise utilize its credit facilities to maintain its targeted available liquidity of $250 million.

We expect to maintain liquidity in excess of our targeted level, and to accumulate additional cash to extinguish all or the majority of the TECO Energy 2007 debt maturities without raising external capital. In January 2005, we received $180 million of proceeds from the final settlement of our equity security units, and we expect to receive net proceeds of approximately $86 million upon the completion of the sale of the Commonwealth Chesapeake Power Station near the end of the first quarter of 2005.

It is possible that unforeseen cash requirements and/or shortfalls or higher capital spending requirements could cause us to fall short of our liquidity target or to require external capital to meet the 2007 TECO Energy debt maturities (see the **Investment Considerations** section).

**Credit Facilities**

At Dec. 31, 2004, we had a bank credit facility in place of $200 million with a maturity date of July 2007, and Tampa Electric had bank credit facilities totaling $275 million with maturity dates in November 2006 and October 2007, as described below. Our TECO Energy bank credit facility includes a $100 million sublimit for letters of credit. The TECO Energy facility was undrawn at Dec. 31, 2004, except for $27.4 million of outstanding letters of credit. At Dec. 31, 2004, $115 million was drawn on the Tampa Electric credit facilities.

Our $200 million credit facility was an early replacement for the $350 million credit facility that was due to expire in November 2004. This facility is secured by the stock of TECO Transport Corporation, which is to be released upon our achieving an investment grade credit rating at both Standard & Poor's (S&P) and Moody's. The replacement facility has two financial covenants, earnings before interest, taxes, depreciation and amortization (EBITDA)-to-interest and debt-to-EBITDA, but no debt-to-total capital covenant (see the **Covenants in Financing Agreements** section).

In October 2004, Tampa Electric Company replaced its expiring $125 million 364-day credit facility with a new $150 million facility that expires in October 2007. Tampa Electric Company now has two multi-year bank credit facilities with total capacity of $275 million: the new $150 million facility and the $125 million facility that expires in November 2006. At the time the replacement facility was put in place, the existing facility was amended to conform the financial covenant requirements to the new facility levels. Both facilities contain two financial covenants, EBITDA-to-interest and debt-to-capital (see the **Covenants in Financing Agreements** section).

Tampa Electric's bank credit facilities require commitment fees of 17.5 - 25 basis points, and drawn amounts are charged interest at LIBOR plus 70 - 112.5 basis points at current credit ratings. TECO Energy's $200 million three-year credit facility requires commitment fees of 50 basis points, and drawn amounts incur interest expense at LIBOR plus 200 basis points at current ratings.

In January 2005, Tampa Electric Company and TEC Receivables Corp. (TRC), a wholly-owned subsidiary of Tampa Electric, entered into a $150 million accounts receivable securitized borrowing facility. Under this facility, Tampa Electric will sell and/or contribute to TRC all of its receivables for the sale of electricity or gas to its customers and related rights. The receivables will be sold by Tampa Electric to TRC at a discount, which will initially be 2%. The discount is subject to adjustment for future sales to reflect changes in prevailing interest rates and collection experience. TRC will be consolidated in the financial statements of Tampa Electric and TECO Energy.

Under a Loan and Servicing Agreement, TRC may borrow up to $150 million to fund its acquisition of the receivables under the facility, and TRC will secure such borrowings with a pledge of all of its assets, including the receivables. Tampa Electric will act as servicer to service the collection of the receivables. TRC will pay program and liquidity fees based on Tampa Electric's credit ratings, which total 35 basis points at Tampa Electric's current ratings. Interest rates on the borrowings are expected to be based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to either the London interbank deposit rate plus a margin of 100 basis points at Tampa Electric's current ratings or at Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher). The facility includes the following financial covenants: (i) for the 12-months ending each quarter-end, the ratio of Tampa Electric's EBITDA-to-interest, as defined in the agreement, must be equal to or exceed 2.0 times; (ii) at each quarter-end, Tampa Electric's debt-to-capital ratio, as defined in the agreement, must not exceed 60%; and (iii) certain dilution and delinquency ratios with respect to the receivables.

At TECO Energy, we have not had access to the commercial paper market since the September 2002 downgrade by S&P of our commercial paper program to A3. Tampa Electric Company continued to have access to the commercial paper market until the S&P downgrade of its commercial paper program to A3 in June 2003. The lack of access to the commercial paper market has caused TECO Energy and Tampa Electric Company to utilize bank credit facilities for short-term borrowing needs.

In February 2004, we repaid in full a one-year $37.5 million credit facility collateralized by 50% of the interests in Union and Gila River projects. The proceeds from the credit facility were used in the termination of the joint venture agreement with Panda Energy.

**Covenants in Financing Agreements**

In order to utilize their respective bank credit facilities, TECO Energy and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements (see **Credit Facilities** above). In addition, TECO Energy, Tampa Electric Company and other operating companies have certain restrictive covenants in specific agreements and debt instruments. TECO Energy, Tampa Electric Company and the other operating companies are in compliance with all required financial covenants except for those related to the Union and Gila River project companies as noted in footnote 5 in the table that follows. The table that follows lists the covenants and the performance relative to them at Dec. 31, 2004. Reference is made to the specific agreements and instruments for more details.

**TECO Energy Significant Financial Covenants**

| *(millions, unless otherwise indicated)* Instrument | *Financial Covenant* (1) | *Requirement/Restriction* | *Calculation at Dec. 31, 2004* |
|---|---|---|---|
| **Tampa Electric Company** | | | |
| PGS senior notes | EBIT/interest (2) | Minimum of 2.0 times | 3.5 times |
| | Restricted payments | Shareholder equity at least $500 | $1,662 |
| | Funded debt/capital | Cannot exceed 65% | 49.5% |
| | Sale of assets | Less than 20% of total assets | – % |
| Credit facilities | Debt/capital | Cannot exceed 60% | 49.7% |
| | EBITDA/interest (2) | Minimum of 2.0 times | 5.5 times |
| 6.25% senior notes | Debt/capital | Cannot exceed 60% | 49.7% |
| | Limit on liens | Cannot exceed $787 | $287 liens outstanding |
| **TECO Energy** | | | |
| Credit facility | Debt/EBITDA (2) | Cannot exceed 5.25 times | 4.5 times |
| | EBITDA/interest (2) | Minimum of 2.25 times | 2.7 times |
| | Limit on additional indebtedness | Cannot exceed $100 million | $ – |
| $380 million note indenture | Limit on restricted payments (3) | Cumulative operating cash flow in excess of 1.7 times interest | $257 unrestricted |
| | Limit on liens | Cannot exceed 5% of tangible assets | $236 unrestricted |
| | Limit on indebtedness | Interest coverage at least 2.0 times | 2.5 times |
| $300 million note indenture | Limit on liens | Cannot exceed 5% of tangible assets | $236 unrestricted |
| Union and Gila River project guarantees (4) | Debt/capital | Cannot exceed 65% | 70.0% (5) |
| | EBITDA/interest (2) | Minimum of 3.0 times | 1.9 times (5) |
| **TECO Diversified** | | | |
| Coal supply agreement guarantee | Dividend restriction | Net worth not less than $418 (40% of tangible net assets) | $564 |

(1) As defined in each applicable instrument.
(2) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant agreements.
(3) The limitation on restricted payments restricts the company from paying dividends or making distributions or certain investments unless there is sufficient cumulative operating cash flow, as defined, in excess of 1.7 times interest to make such distribution or investment. The operating cash flow and restricted payments are calculated on a cumulative basis since the issuance of the 10.5% Notes in the fourth quarter of 2002. This calculation at Dec. 31, 2004 reflects the amount accumulated since the issuance of the notes and available for future restricted payments.
(4) Includes the Construction Undertakings related to the Union and Gila River projects.
(5) The TECO Energy guarantees of the equity contribution agreements of TPGC and the Construction Undertakings contain debt/capital and EBITDA/interest financial covenants. The Company was not in compliance with the EBITDA/interest covenant at any quarterly measurement period in 2004 and was not in compliance with the debt/capital covenant at Dec. 31, 2004. Non-compliance constitutes a default under the non-recourse bank credit agreements of the Union and Gila River project companies (TPGC), but does not create a cross-default under any TECO Energy agreement. In December 2003, the Union and Gila River project companies were unable to make interest payments on the non-recourse debt and payments under interest rate swap agreements due Dec. 31, 2003 when the project lenders declined to fund the debt service reserve. Subsequently, the project companies, the project lenders and TECO Energy entered into a series of discussions and agreements and as of Dec. 31, 2004, the Company announced that an agreement had been reached with the steering committee of the project lenders on all material terms and forms of definitive agreements for the sale and transfer to the lenders of ownership of these plants. See **Note 21** to the **Consolidated Financial Statements** for further discussion of this agreement and **Note 23** for details of a related subsequent event.

**Credit Ratings/Senior Unsecured Debt**

| | *Standard & Poor's* | *Moody's* | *Fitch* |
|---|---|---|---|
| Tampa Electric | BBB- | Baa2 | BBB+ |
| TECO Energy / TECO Finance | BB | Ba2 | BB+ |

In December 2004, Fitch Ratings affirmed our ratings and those of Tampa Electric and revised the rating outlook to stable from negative. The outlook revision was attributed to positive developments over the previous 18 months that included the sale of merchant power and other non-core assets, the 2004 sale of the 40.5% membership interest in TECO Coal's synthetic fuel production facilities and the successful replacement of TECO Energy's credit facilities with a three-year credit facility.

In July 2004, S&P lowered the ratings on our senior unsecured debt securities from BB+ with a negative outlook to BB with a stable outlook. At the same time, S&P affirmed Tampa Electric Company's senior unsecured debt securities rating at BBB- and changed the outlook to stable. At the time of the ratings action, S&P stated that the drop in the TECO Energy rating was based on their expectation of lower financial performance at TECO Energy and less support to TECO Energy from Tampa Electric. In affirming Tampa Electric's rating, S&P noted that they acknowledged the wide differential in the stand-alone credit profiles of TECO Energy and Tampa Electric, and that Tampa Electric was unlikely to suffer further deterioration from TECO Energy's activities. S&P further noted that management's actions over the past three years had been consistent with maintaining Tampa Electric's strong investment-grade credit quality.

In February 2004, Moody's lowered the ratings on TECO Energy's senior unsecured debt securities to Ba2 and the ratings on Tampa Electric's senior unsecured securities to Baa2, both with a ratings outlook of negative. These ratings changes followed downgrades by Moody's, S&P and Fitch in 2003, 2002 and 2001 due to the effects of merchant power investments on our business risk and financial position.

Any future downgrades in credit ratings may affect our ability to borrow and may increase financing costs, which may decrease earnings. Our interest expense would increase if maturing debt in 2007 were not retired, and instead it was replaced with new debt with higher interest rates due to the lower credit ratings.

**Summary of Contractual Obligations**

The following table lists the obligations of TECO Energy and its subsidiaries for cash payments to repay debt, lease payments and unconditional commitments related to capital expenditures. This table does not include contingent obligations, which are discussed in a subsequent table.

**Contractual Cash Obligations (1)**

| | | | *Payments Due by Period* | | | |
|---|---|---|---|---|---|---|
| *(millions)* | *Total* | *2005* | *2006* | *2007* | *2008-2009* | *After 2009* |
| Long-term debt: | | | | | | |
| Recourse | $ 3,613.7 | $ 5.5 | $ 5.9 | $ 946.7 | $ 11.2 | $ 2,644.4 |
| Non-recourse (2) | 21.5 | 8.1 | 10.8 | 0.9 | 1.7 | – |
| Junior subordinated notes | 277.6 | – | – | 71.4 | – | 206.2 |
| Operating leases/rentals | 157.0 | 25.2 | 20.7 | 17.2 | 25.6 | 68.3 |
| Purchase obligations/commitments (3) | 134.8 | 57.1 | 24.4 | 23.8 | 29.5 | – |
| Total contractual obligations (4) | $ 4,204.6 | $ 95.9 | $ 61.8 | $ 1,060.0 | $ 68.0 | $ 2,918.9 |

(1) Excludes annual interest payments (see **Note 7 to the Consolidated Financial Statements** for a list of long-term debt and the associated interest rates).
(2) Excludes the $1.4 billion of non-recourse debt associated with the Union and Gila River projects which is included in liabilities associated with assets held for sale.
(3) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2004, these commitments include Tampa Electric's outstanding commitments of about $105 million primarily for long-term capitalized maintenance agreements for its combustion turbines, and the $30 million payment due to the lenders upon completion of the final transfer of Union and Gila River.
(4) The total excludes a $13.6 million contribution to the qualified pension plan and a $9.8 million contribution to the other postretirement employee benefits plans in 2005. No future contributions are included as they are subject to annual valuation reviews, which may vary significantly due to changes in interest rates, discount rate assumptions, plan asset performance which is affected by stock market performance, and other factors (see **Note 5 to the Consolidated Financial Statements**).

**Summary of Contingent Obligations**

The following table summarizes the letters of credit and guarantees outstanding that are not included in the Summary of Contractual Obligations table above and not otherwise included in our Consolidated Financial Statements.

**Contingent Obligations**

| | | | | *Commitment Expiration* | | |
|---|---|---|---|---|---|---|
| *(millions)* | | *Total (2)* | *2005* | *2006* | *2007-2009* | *After 2009* |
| Letters of credit (1) | | $ 29.5 | $ – | $ 4.7 | $ – | $ 24.8 |
| Guarantees: | Debt related | 10.2 | – | – | – | 10.2 |
| | Fuel purchase/energy management | 203.6 | 174.9 | – | – | 28.7 (3) |
| | Other | 13.4 | 12.0 | – | – | 1.4 |
| Total contingent obligations | | $ 256.7 | $ 186.9 | $ 4.7 | $ – | $ 65.1 |

(1) Expected final expiration date with annual renewals.
(2) Expected maximum exposure.
(3) These guarantee amounts renew annually and are shown on the basis of our intent to renew beyond the current expiration date.

## *Capital Investments*

**Capital Investments**

| *(millions)* | *Actual* 2004 | *Forecast* 2005 | 2006 | 2007-2009 | 2005-2009 Total |
|---|---|---|---|---|---|
| Tampa Electric | | | | | |
| Transmission | **$ 15** | $ 19 | $ 25 | $ 99 | $ 143 |
| Distribution | **90** | 75 | 78 | 236 | 390 |
| Generation | **48** | 56 | 58 | 191 | 304 |
| Other | **15** | 20 | 16 | 43 | 79 |
| Environmental | **12** | 44 | 69 | 286 | 399 |
| Tampa Electric | **$180** | $ 214 | $ 246 | $ 855 | $1,315 |
| Peoples Gas | **39** | 40 | 40 | 120 | 200 |
| TECO Coal | **23** | 24 | 22 | 55 | 101 |
| TECO Transport | **20** | 20 | 20 | 59 | 99 |
| Other | **10** | 5 | – | 1 | 6 |
| Total | **$272** | $ 303 | $ 328 | $1,090 | $1,721 |

TECO Energy's 2004 capital investments of $272 million (without reduction for asset and business sale proceeds) included $180 million for Tampa Electric, $39 million for PGS and $3 million for the unregulated Florida operations. Tampa Electric's electric division capital investments in 2004 were primarily for equipment and facilities to meet its growing customer base and generating equipment maintenance. Capital expenditures for PGS were approximately $24 million for system expansion and approximately $15 million for maintenance of the existing system. TECO Coal's capital expenditures included $23 million for normal mining equipment replacement. TECO Transport invested $20 million in 2004 primarily for capitalized maintenance of ocean-going vessels.

Asset sale proceeds in 2004 were $315 million net of escrowed cash of $35 million. Included in the proceeds were the sale of the Hamakua and Frontera power stations, the sale of Prior Energy, the sale of our investment in the propane business, TECO Transport's sale of equipment no longer used at TECO Ocean Shipping and scrap river barges, and TECO Coal's sale of membership interests in its synthetic fuel production facilities (see the **TECO Coal** and **Liquidity, Capital Resources** sections).

TECO Energy estimates capital spending for ongoing operations, without reduction for proceeds from asset sales, to be $303 million for 2005 and $1,418 million during the 2006–2009 period.

For 2005, Tampa Electric's electric division expects to spend $214 million, consisting of about $170 million to support system growth and generation reliability and $44 million for environmental compliance, including $30 million for the addition of selective catalytic reduction (SCR) equipment at the Big Bend Power Station. At the end of 2004, Tampa Electric had outstanding commitments of about $105 million primarily for long-term capitalized maintenance agreements for its combustion turbines. Tampa Electric's total capital expenditures over the 2006–2009 period are projected to be $1,101 million, including $254 million for compliance with the Environmental Consent Decree for the SCR equipment and $101 million for other required environmental capital expenditures. The environmental compliance expenditures are eligible for recovery of depreciation and a return on investment through the Environmental Cost Recovery Clause (see the **Environmental Compliance** section).

Capital expenditures for PGS are expected to be about $40 million in 2005 and $160 million during the 2006–2009 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

TECO Coal and TECO Transport expect to invest a combined $44 million in 2005 and $156 million during the 2006–2009 period. Included in these amounts is normal renewal and replacement capital, including coal mining equipment and capitalized maintenance on ocean-going vessels and inland river transportation equipment.

## *Financing Activity*

Our 2004 year-end capital structure, excluding the effect of unearned compensation, was 71.8% senior debt, 3.9% junior subordinated debt and 24.3% common equity. The debt-to-total-capital ratio increased from last year primarily due to the impairment charges taken in 2004 associated with our investments in merchant power.

In 2004, we did not access the debt and equity markets for new capital, except for short-term borrowings under our credit facilities and the small, recurring amount of equity raised through our dividend reinvestment plan. In 2003, we accessed the debt and equity capital markets on three occasions, raising $672 million to provide funds for general liquidity purposes, to repay long-term debt, and reduce short-term debt balances. In addition, debt proceeds in 2003 included non-recourse proceeds of $111 million associated with the Union and Gila River power projects.

In 2004, we completed an early settlement offer on our 9.5% Adjustable Conversion-Rate Equity Security Units (units). Under the terms of the offer, each unit holder received 0.9509 shares of TECO Energy common stock for each unit held and $1.39 per unit in cash, which included the future quarterly distributions through the normal settlement date and a $0.20 per unit incentive. Under the early settlement offer, 10.8 million units were exchanged for 10.2 million shares of our common stock, and we paid $14.9 million of cash for future distributions and incentives. The effect of the exchange was that we retired $269 million, or about 60%, of the associated trust preferred securities and increased the common shares outstanding three months earlier than would have otherwise occurred.

In 2004, we remarketed the remaining $163 million of outstanding trust preferred securities associated with the units within TECO Capital Trust II, as required. We purchased and subsequently retired $123 million of the securities offered in this transaction. Our purchase was funded through a $124 million bridge loan with Merrill Lynch and JP Morgan, which we repaid in December 2004. Trust preferred securities totaling $71 million of this series remain outstanding, including the 3% ($14 million ) held by TECO Capital Trust II, and have a coupon rate of 5.93% which was set in the remarketing. The proceeds from the remarketing were used by the Trustee to purchase a portfolio of US Treasury securities with a January 2005 maturity. Upon final settlement of the units in January 2005, we issued 6.85 million shares of TECO Energy common stock and received $180 million of cash proceeds from the matured U.S. Treasury securities.

The following table provides details of the financing activities beginning in 2002.

| *Date* | *Security* | *Company* | *Net Proceeds (millions)* | *Coupon* | *Use* |
|---|---|---|---|---|---|
| Jan. 2005 | Common equity [1] | TECO Energy | $ 180 | – | Final settlement |
| Jan. 2005 | Credit facility | Tampa Electric | $ 150 | – | Accounts receivable facility |
| Oct. 2004 | Trust preferred securities [2] | TECO Energy | $ 0 | 5.93% | Required TECO Capital Trust II remarketing |
| Oct. 2004 | Credit facility | Tampa Electric | $ 150 | – | 3-year facility |
| Aug. 2004 | Common equity [3] | TECO Energy | $ 0 | – | Early settlement of equity units |
| July 2004 | Credit facility | TECO Energy | $ 200 | – | 3-year facility |
| Nov. 2003 | Credit facility | Tampa Electric | $ 125<br>$ 125 | –<br>– | 364-day facility<br>3-year facility |
| Sep. 2003 | Common equity | TECO Energy | $ 129 | – | Repay short-term debt, and general corporate purposes |
| Jun. 2003 | 7-year notes | TECO Energy | $ 293 | 7.5% | Repay short-term debt, and general corporate purposes |
| Apr. 2003 | 13-year notes | Tampa Electric | $ 250 | 6.25% | Repay maturing short-term debt, and general corporate purposes |
| Dec. 2002 | 7-year non-recourse bank loan | TECO Wholesale Generation | $ 30 | 6.0% | Refinance Alborada Power Station and general corporate purposes |
| Nov. 2002 | 5-year notes | TECO Energy | $ 352 | 10.5% | Repay short- and long-term debt, and general corporate purposes |
| Oct. 2002 | Common equity | TECO Energy | $ 207 | – | Repay short-term debt, and general corporate purposes |
| Aug. 2002 | 5-year notes | Tampa Electric | $ 149 | 5.375% | Repay maturing long-and short-term debt, and general corporate purposes |
| Aug. 2002 | 10-year notes | Tampa Electric | $ 394 | 6.375% | Repay maturing long-and short-term debt, and general corporate purposes |
| Jun. 2002 | Pollution control bonds | Tampa Electric | $ 61 | 5.1% | Refinance higher cost debt |
| Jun. 2002 | Pollution control bonds | Tampa Electric | $ 86 | 5.5% | Refinance higher cost debt |
| Jun. 2002 | Common equity | TECO Energy | $ 346 | – | Repay short-term debt, and general corporate purposes |
| May 2002 | 5-year notes | TECO Energy | $ 297 | 6.125% | Repay maturing short-term debt, and general corporate purposes |
| May 2002 | 10-year notes | TECO Energy | $ 397 | 7.0% | Repay maturing short-term debt, and general corporate purposes |
| Jan. 2002 | Mandatorily convertible equity units | TECO Energy | $ 436 | 9.5% | Repay short-term debt, and general corporate purposes |

(1) 6.8 million shares issued in the final settlement of the 9.5% convertible equity units
(2) No increase in outstanding debt, interest rate reset
(3) 10.2 million shares issued in an early settlement offer on the 9.5% convertible equity units

## *Off-Balance Sheet Financing*

Unconsolidated affiliates have project debt balances as follows at Dec. 31, 2004. We had no debt payment obligations with respect to these financings. Although we are not directly obligated on the debt, our equity interest in those unconsolidated affiliates and its commitments with respect to those projects are at risk if those projects are not operated successfully.

**Off-Balance Sheet Debt**

| *(millions)* | *Long-term Debt* | *Ownership Interest* |
|---|---|---|
| San José Power Station | $ 110.5 | 100% |
| Alborada Power Station | $ 21.7 | 94% |
| Empresa Eléctrica de Guatemala S.A.(EEGSA) | $ 182.7 | 24% |

The equity method of accounting is used to account for investments in partnership and corporate entities in which we or our subsidiary companies do not have either a majority ownership or exercise control. On Jan. 17, 2003, the Financial Accounting Standards Board issued FASB Interpretation FIN No. 46, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51,* which requires a new approach in determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as variable interest entities or VIEs. On Dec. 24, 2003, the FASB published a revision to FIN 46 (FIN46R), to clarify some of the provisions of FIN 46 and exempt certain entities from its requirements.

We deconsolidated the San José and Alborada power stations listed above in the first quarter of 2004 as a result of implementing FIN 46R. These projects were partially financed with non-recourse debt, which following the deconsolidation is considered to be off-balance sheet financing. (This and other effects of implementing FIN 46R are described in **Note 2** to the **Consolidated Financial Statements.**)

## *Critical Accounting Policies and Estimates*

The preparation of consolidated financial statements requires management to make various estimates and assumptions that affect revenues, expenses, assets, liabilities and the disclosure of contingencies. The policies and estimates identified below are, in the view of management, the more significant accounting policies and estimates used in the preparation of our consolidated financial statements. These estimates and assumptions are based on historical experience and on various other factors that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and judgments under different assumptions or conditions. (See **Note 1** to the **Consolidated Financial Statements** for a description of our significant accounting policies and the estimates and assumptions used in the preparation of the consolidated financial statements.)

**Long-Lived Assets**

In accordance with Financial Accounting Standard (FAS) 144, *Accounting for the Impairment or Disposal of Long- Lived Assets,* we assess whether there has been an other than temporary impairment of our long-lived assets and certain intangibles held and used by us when such indicators exist. Also, we annually test the long-lived assets in the last quarter of each year to ensure that gradual change over the year and the seasonality of the markets are considered in the impairment analysis. We believe the accounting estimates related to asset impairments are critical estimates for the following reasons: 1) the estimates are highly susceptible to change as management is required to make assumptions based on expectations of the results of operations for significant/indefinite future periods and/or the then current market conditions in such periods; 2) markets can experience significant uncertainties; 3) the estimates are based on the ongoing expectations of management regarding probable future uses and holding periods of assets; and 4) the impact of an impairment on reported assets and earnings could be material. Our assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Our expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

During the fourth quarter of 2004, as a part of its annual impairment review, management conducted a review of the prospects for long-term power prices as well as opportunities for actual sales of assets. As a result of this review, we sold the Frontera project and determined it was appropriate to reduce the probability that the Dell, McAdams and Commonwealth Chesapeake projects would be held for use for the overall economic life of those projects. The first step in the impairment testing was weighted more toward an ultimate recovery of the investment. In each case, the testing resulted in a determination that the carrying value of each project was not recoverable. This recoverability test is conducted by comparing the probability weighted undiscounted cash flows for the asset to its carrying value. If the test is not passed, a second step is required. Each of the projects listed above required the second step, in which the difference between the fair market value of the projects and the carrying value was estimated in order to determine and record appropriate impairment charges. Critical estimates are also inherent in determining the fair market value. We based the fair market values on probability weighted values. To the extent actual fair market value should vary from the probability weighted average values, future impairment charges or gains on disposition could occur (see **Note 18** to the **Consolidated Financial Statements** for the discussion on the asset impairments).

When specific criteria are met, a disposal group, comprised of assets and liabilities expected to be transferred in a sale within one year, is classified in assets and liabilities, respectively, and held for sale. Furthermore, the income or loss associated with a disposal group may, if additional criteria are met, be presented as discontinued operations in the statement of income. The Union and Gila projects, Frontera, Prior Energy, TECO BGA, TECO BCH, TECO AGC, and TECO Coalbed Methane are classified as assets and liabilities held for sale, and the results associated these investments are presented as discontinued operations (see **Notes 1, 18** and **21** to the **Consolidated Financial Statements**).

**Goodwill and Other Intangible Assets**

In accordance with FAS 142, *Goodwill and Other Intangible Assets,* we review goodwill and intangibles for each reporting unit at least annually for impairment. Reporting units are generally determined as one level below the operating segment level; however, reporting units with similar characteristics may be grouped under the accounting standard for the purpose of determining the impairment, if any, of goodwill and other intangible assets. The goodwill impairment test is a two-step process, which requires management to make judgments in determining what assumptions to use in the calculation. The first step of the process consists of estimating the fair value of each reporting unit based on a discounted cash flow model using revenue and profit forecasts and comparing those estimated fair values with the carrying values, which include the goodwill. If the estimated fair value is less than the carrying value, a second step is performed to compute the amount of the impairment by determining an implied fair value of goodwill. Estimating the reporting unit's implied fair value of goodwill requires the Company to allocate the estimated fair value of the reporting unit to the assets and liabilities of the reporting unit. Any unallocated fair value represents the implied fair value of goodwill, which is compared to its corresponding carrying value. During the fourth quarter of 2004, as a result of current conditions in the energy services market, we were required to recognize an impairment charge for the goodwill related to the BCH reporting unit. This $11.8 million pretax impairment charge completely eliminated the goodwill associated with that investment. This impairment charge is reflected in discontinued operations as we subsequently sold this unit.

The company had $59.4 million of goodwill remaining on its balance sheet at Dec. 31, 2004, which was related to its Guatemalan reporting unit. Assuming a 9% discount rate, which management believes is appropriate since these projects have long-term power purchase agreements, the goodwill was not impaired. Assuming a 1% increase in the discount rate would not reduce the implied fair value of the goodwill to an extent that an impairment charge would be necessary. Increasing the discount rate 3%, to 12%, to calculate the implied fair value of the goodwill would have resulted in an approximate $1 million pretax impairment charge (see **Note 17** to the **Consolidated Financial Statements**).

**Equity Investments**

In accordance with APB No. 18, *The Equity Method of Accounting for Investments in Common Stock,* we only record an impairment of an equity investment when a decline in the fair value below the carrying value of the investment is determined to be other than temporary. The accounting estimate of impairment of equity investments is critical, since management must assess other than temporary impairments based on: 1) the magnitude of the difference of the fair value below the carrying value; 2) the period of time in which the decline in the fair value is less than the carrying value; and 3) other reasonably available qualitative or quantitative information that provides evidence to indicate that a decline in fair value is temporary. During the year ended Dec. 31, 2004, the company recorded an impairment of an equity investment in Texas Independent Energy, (TIE). This impairment charge was driven by management's decision to not make additional investments in this project, which materially impacted the impairment assessment (see **Note 16** to the **Consolidated Financial Statements**).

**Deferred Income Taxes**

We use the liability method in the measurement of deferred income taxes. Under the liability method, we estimate our current tax exposure and assess the temporary differences resulting from differing treatment of items, such as depreciation for financial statement and tax purposes. These differences are reported as deferred taxes measured at current rates in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward looking information, to determine if it is more likely than not that some or all of the deferred tax asset will not be realized. If we determine that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

At Dec. 31, 2004, we had net deferred income tax assets of $875.0 million attributable primarily to losses or expected losses on asset dispositions, property related items, alternative minimum tax credit carryover of Section 29 non-conventional fuel tax credits and operating loss carry forwards. Based primarily on historical income levels and the steady growth expectations for future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2004 will be realized in future periods.

We believe that the accounting estimate related to deferred income taxes, and any related valuation allowance, is a critical estimate for the following reasons: 1) realization of the deferred tax asset is dependent upon the generation of sufficient taxable income in future periods; 2) a change in the estimated valuation reserves could have a material impact on reported assets and results of operations; and 3) administrative actions of the IRS or the U.S. Treasury or changes in law or regulation could change our deferred tax levels, including the potential for elimination or reduction of our ability to utilize the deferred tax assets (see **Note 4** to the **Consolidated Financial Statements**).

**Accounting for Contingencies**

In accordance with FAS 5, *Accounting for Contingencies*, we make estimates at the end of each reporting period to record the probable loss related to contingent liabilities. Examples of such expected losses and respective contingent liabilities would include legal contingencies and incurred but not reported medical and general liability claims. We consider these estimates of liabilities to be critical since the company must first determine the likelihood that the known claims or legal events will result in a future loss to the company. Then we must determine if the future amount of expected loss can be reasonably estimated.

For a known claim, if the company determines that it is probable that future events will result in a loss and that loss can be reasonably estimated, the expected loss and respective liability are recorded. If we determine that the likelihood is remote that those future events will develop in a manner that will result in a loss to the company, no loss or liability is recorded. If there is more than a remote possibility but it is less than likely that future events will result in a loss to the company, we disclose the specific claim or situation if it is material.

For medical and general liability claims that have been incurred but not reported, we rely on a third-party actuary to advise us as to probable liabilities that will become known in the future but were incurred in the current reporting period, and we record the expected loss and liability accordingly.

Many of the material claims that have been made or could be made against the company in the future are covered by insurance. Accounting for the expected loss and liability under FAS 5 has different recognition criteria than expected insurance recoveries such that it is possible that the company could have to report a loss and respective liabilities in accounting periods before the offsetting gain from the insurance recovery could be reported.

While the company carefully evaluates all known claims and cases to record the most probable outcome, future events could develop in an unexpected manner that could have a material impact on future financial statements (see **Note 12** to **Consolidated Financial Statements** for a complete discussion of certain legal contingencies that existed at Dec. 31, 2004).

**Employee Postretirement Benefits**

We sponsor a defined benefit pension plan that covers substantially all of our employees. In addition, we have unfunded non-qualified, non-contributory supplemental executive retirement benefit plans available to certain senior management. Several statistical and other factors, which attempt to anticipate future events, are used in calculating the expense and liability related to these plans. Key factors include assumptions about the expected rates of return on plan assets, discount rates and health care cost trend rates. These factors are determined by us within certain guidelines, with the help of external experts. We consider market conditions, including changes in investment returns and interest rates, in making these assumptions.

Plan assets are invested in a mix of equity and fixed income securities. The assumptions for the expected return on plan assets are developed based on an analysis of historical market returns, the plan's actual past experience and current market conditions. The expected rate of return on plan assets is a long-term assumption and is not intended to change annually. The discount rate assumption is based on a cash flow matching technique developed by our outside actuaries, and this assumption is subject to change each year. The salary increase assumption is a rate based on current expectations of future pay increases and is linked with our discount rate assumption. Holding all other assumptions constant, a 1% increase or decrease in the assumed rate of return on plan assets would decrease or increase, respectively, 2004 net periodic expense by approximately $4.5 million. Likewise, a 0.25% increase or decrease in the discount rate and the related change in the rate of salary increase would not result in a significant decrease or increase in net periodic pension expense.

Unrecognized actuarial gains and losses are being recognized over approximately a 15-year period, which represents the expected remaining service life of the employee group. Unrecognized actuarial gains and losses arise from several factors including experience and assumption changes in the obligations and from the difference between expected return and actual returns on plan assets. These unrecognized gains and losses will be systematically recognized in future net periodic pension expense in accordance with FASB Statement No. 87, *Employer's Accounting for Pensions*. Our policy is to fund the plan based on the required contribution determined by our actuaries within the guidelines set by the Employee Retirement Income Security Act of 1974 (ERISA), as amended.

In addition, we currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 who meet certain service requirements. The key assumptions used in determining the amount of obligation and expense recorded for postretirement benefits other than pension (OPEB), under FAS 106, *Employers' Accounting for Postretirement Benefits Other Than Pensions*, include the assumed discount rate and the assumed rate of increases in future health care costs. The discount rate used to determine the obligation for these benefits has matched the discount rate used in determining our pension obligation in each year presented. In estimating the health care cost trend rate, we consider our actual health care cost experience, future benefit structures, industry trends and advice from our outside actuaries. We assume that the relative increase in health care cost will trend downward over the next several years, reflecting assumed increases in efficiency in the health care system and industry-wide cost containment initiatives. In December 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Act") was enacted. The Act established a prescription drug benefit under Medicare, known as "Medicare Part D," and a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription benefit which is at least actuarially equivalent to Medicare Part D. In May 2004, the FASB issued FASB Staff Position No. FSP 106-2 which required (1) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (2) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

We adopted FSP 106-2 retroactive to the second quarter of 2004 for benefits provided that we believe to be actuarially equivalent to Medicare Part D. This initial recognition reduced the accumulated postretirement benefit obligations (ABPO) at Jan. 1, 2004 by $27.0 million and net periodic cost for 2004 by $2.8 million. Although additional guidance on actuarial equivalence is scheduled for release in early 2005, we do not anticipate that it will materially impact the amounts provided in this disclosure. The assumed health care cost trend rate for medical costs was 10.5% in 2004 and decreases to 5.0% in 2013 and thereafter.

A 1% increase in the health care trend rates would produce an 8% ($1.2 million) increase in the aggregate service and interest cost for 2004 and a 5% ($8.5 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2004.

A 1% decrease in the health care trend rates would produce a 6% ($0.9 million) decrease in the aggregate service and interest cost for 2004 and a 3% ($6.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2004.

The actuarial assumptions we used in determining our pension and OPEB retirement benefits may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, or longer or shorter life spans of participants. While we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions may materially affect our financial position or results of operations.

**Depreciation Expense**

As of Dec. 31, 2004, approximately 71% of our total gross property, plant and equipment was comprised of regulated electric utility assets. We provide for depreciation primarily by the straight line method at annual rates that amortize the original cost, less net salvage, of depreciable property over its estimated service life. For the year ended Dec. 31, 2003, Tampa Electric recognized depreciation expense of $36.6 million related to accelerated depreciation of certain Gannon power station coal-fired assets, in accordance with a regulatory order. We believe the estimated service life corresponds to the anticipated physical life for most assets. However, our estimation of service life is a critical estimate for the following reasons: 1) forecasting the salvage value for long-lived assets over a long timeframe is subjective; 2) changes may take place that could render a technology obsolete or uneconomical; and 3) a change in the useful life of a long-lived asset could have a material impact on reported results of operations and reported assets. A 10% decrease, on a weighted average basis, in the service lives of our overall utility plant in service would increase pretax depreciation approximately $24.8 million per year (see **Note 1** to the **Consolidated Financial Statements**).

**Regulatory Accounting**

Tampa Electric's and PGS' retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the Federal Energy Regulatory Commission (FERC). As a result, the regulated utilities qualify for the application of FAS 71, *Accounting for the Effects of Certain Types of Regulation.* This statement recognizes that the actions of a regulator can provide reasonable assurance of the existence of an asset or liability. Regulatory assets and liabilities arise as a result of a difference between generally accepted accounting principles and the accounting principles imposed by the regulatory authorities. Regulatory assets generally represent incurred costs that have been deferred, as their future recovery in customer rates is probable. Regulatory liabilities generally represent obligations to make refunds to customers from previous collections for costs that are not likely to be incurred.

We periodically assess the probability of recovery of the regulatory assets by considering factors such as regulatory environment changes, recent rate orders to other regulated entities in the same jurisdiction, the current political climate in the state, and the status of any pending or potential deregulation legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs, the rate earned on invested capital and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on reported assets and the results of operations (see the **Regulation Section** and **Notes 1** and **3** to the **Consolidated Financial Statements**).

**Revenue Recognition**

Except as discussed below, we recognize revenues on a gross basis when the risks and rewards of ownership have transferred to the buyer and the products are physically delivered or services provided. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The determination of the physical delivery of energy sales to individual customers is based on the reading of meters, which occurs on a regular basis. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading may be estimated, and the corresponding unbilled revenue is estimated. Unbilled revenue is estimated each month primarily based on historical experience, customer specific factors, customer rates, and daily generation volumes, as applicable. These revenues are subsequently adjusted to reflect actual results. Revenues for regulated activities at Tampa Electric and PGS are subject to the actions of regulatory agencies.

The percentage-of-completion method is used to recognize revenues for certain transportation services at TECO Transport. The percentage-of-completion method requires management to make estimates regarding the distance traveled and/or time elapsed. Revenue is recognized by comparing the estimated current total distance traveled with the total distance required. Each month revenue recognition and realized profit are adjusted to reflect only the percentage of distance traveled.

Revenues for merchant power sales and expenses for fuel purchases at TWG are reported on a gross basis, except for derivative gains or losses related to hedge accounting, which are reported net of the hedged item or transaction. Likewise, expenses arising from purchased power or revenues arising from sales at TWG are reported net of power revenues and expenses, respectively.

We estimate certain amounts related to revenues on a variety of factors, as described above. Actual results may be different from these estimates (see **Note 1** to the **Consolidated Financial Statements**).

## *Recently Issued Accounting Standards*

In accordance with recently issued accounting pronouncements, we will be required to comply with certain changes in accounting rules and regulations (see **Note 2** to the **Consolidated Financial Statements**).

FASB Statement No. 123 (revised 2004), *Share-Based Payment,* will become effective for periods after Jun. 15, 2005. The revision to FAS 123 will require financial statement cost recognition for certain share-based payment transactions that are made after the effective date in return for goods and services. Additionally, the revision will require financial statement cost recognition for certain share-based payment transactions that have been made prior to the effective date but for which the requisite service is provided after the effective date (see **Note 9** to the **Consolidated Financial Statements,** which includes proforma information to assess the impact of implementing the revised statement).

FASB Statement No. 151, *Inventory Costs, an amendment to ARB No. 43,* Chapter 4, sets forth certain costs related to inventory that must be included as current period costs. This Statement became effective June 2004 and did not materially impact the company.

FASB Statement No. 153, *Exchanges of Non-monetary Assets, an amendment of APB Opinion No. 29,* became effective June 2004 and did not materially impact the company.

## *Market Risk*

**Risk Management Infrastructure**

We are subject to various types of market risk in the course of daily operations, as discussed below. We have adopted an enterprise-wide approach to the management and control of market and credit risk. Middle Office risk management functions, including credit risk management and risk control, are independent of each transacting entity (Front Office).

Our Risk Management Policy (Policy) governs all energy transacting activity at the TECO Energy group of companies. The Policy is approved by our Board of Directors and administered by a Risk Authorizing Committee (RAC) that is comprised of senior management. Within the bounds of the Policy, the RAC approves specific hedging strategies, new transaction types or products, limits, and transacting authorities. Transaction activity is reported daily and measured against limits. For all commodity risk management activities, derivative transaction volumes are limited to the anticipated volume for customer sales or supplier procurement activities.

The RAC administers the risk management policy with respect to interest rate risk exposures. Under the policy for interest rate risk management, the RAC operates and oversees transaction activity. Interest rate derivative transaction activity is directly correlated to borrowing activities.

**Risk Management Objectives**

The Front Offices are responsible for reducing and mitigating the market risk exposures which arise from the ownership of physical assets and contractual obligations, such as merchant power plants, debt instruments and firm customer sales contracts. The primary objectives of the risk management organization, the Middle Office, is to quantify, measure and monitor the market risk exposures arising from the activities of the Front Office and the ownership of physical assets. In addition, the Middle Office is responsible for enforcing the limits and procedures established under the approved risk management policies. Based on the policies approved by the company's Board of Directors and the procedures established by the RAC, from time to time, members of the TECO Energy group of companies enter into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS;
- To limit the exposure to interest rate fluctuations on debt issuances at TECO Energy and its affiliates;
- To limit the exposure to electricity and fuel oil price fluctuations related to the operations of the fuel-oil-fired power plant at TWG; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport.

The TECO Energy group of companies uses derivatives only to reduce normal operating and market risks, not for speculative purposes. Our primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the companies use derivative instruments primarily to optimize the value of physical assets, primarily generation capacity and natural gas delivery.

**Derivatives and Hedge Accounting**

FAS 133, *Accounting for Derivative Instruments and Hedging Activities,* as subsequently amended and interpreted requires us and our affiliates to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as components of other comprehensive income, depending on the designation of those instruments.

Designation of a hedging relationship requires management to make assumptions about the future probability of the timing and amount of the hedged transaction and the future effectiveness of the derivative instrument in offsetting the change in fair value or cash flows of the hedged item or transaction. The determination of fair value is dependent upon certain assumptions and judgments, as described more fully below (see **Other Unregulated Companies** section, and **Note 22** to the **Consolidated Financial Statements**).

**Interest Rate Risk**

We are exposed to changes in interest rates, primarily as a result of our borrowing activities. We may enter into futures, swaps and option contracts, in accordance with the approved risk management policies and procedures, to moderate this exposure to interest rate changes and achieve a desired level of fixed and variable rate debt. As of Dec. 31, 2004, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during 2005, as compared to 2004, would not result in a material impact on pretax earnings. Comparatively, as of Dec. 31, 2003, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during 2004, as compared to 2003, would not have resulted in a material impact on pretax earnings. This is driven by the very low amounts of variable rate debt at either TECO Energy or Tampa Electric. These amounts were determined based on the variable rate obligations existing on the indicated dates at TECO Energy and its subsidiaries. Due to the uncertainty of future events, as discussed in the **Investment Considerations** section, and our responses to those events, the above sensitivities assume no changes to our financial structure. A hypothetical 10% decrease in interest rates would increase the fair market value of our long-term debt by approximately 2.1% and 3.1% at Dec. 31, 2004 and 2003, respectively (see **Financing Activity** section, and **Notes 6** and **7** to the **Consolidated Financial Statements**).

**Credit Risk**

We have adopted a rigorous process for the establishment of new trading counterparties. This process includes an evaluation of each counterparty's financial statements, with particular attention paid to liquidity and capital resources; establishment of counterparty specific credit limits; optimization of credit terms; and execution of standardized enabling agreements. Our Credit Guidelines require transactions with counterparties below investment grade to be collateralized. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Offices.

Financial instability and significant uncertainties relating to liquidity in the entire merchant energy sector have increased the perceived credit risk. Credit exposures for merchant generation activities are calculated, compared to limits and reported to management on a daily basis. Contracts with different legal entities affiliated with the same counterparty are consolidated and managed as appropriate, considering the legal structure and any netting agreements in place.

**Commodity Risk**

We and our affiliates face varying degrees of exposure to commodity risks—including coal, natural gas, fuel oil and other energy commodity prices. Any changes in prices could affect the prices these businesses charge, their operating costs and the competitive position of their products and services. We assess and monitor risk using a variety of measurement tools. Management uses different risk measurement and monitoring tools based on the degree of exposure of each operating company to commodity risk.

**Regulated Utilities**

Historically, Tampa Electric's fuel costs used for generation have been affected primarily by the price of coal and, to a lesser degree, the cost of natural gas and fuel oil. With the repowering of the Bayside Power Station, the use of natural gas, with its more volatile pricing, has increased substantially. PGS has exposure related to the price of purchased gas and pipeline capacity.

Currently Tampa Electric's and PGS' commodity price risk is largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through cost recovery clauses, with no anticipated effect on earnings. Increasing fuel cost recovery has the potential to affect total energy usage and the relative attractiveness of electricity and natural gas to consumers. To moderate the impacts of fuel price changes on rate payers, both PGS and Tampa Electric manage commodity price risk by entering into long-term fuel supply agreements, prudently operating plant facilities to optimize cost, and entering into derivative transactions designated as cash flow hedges of anticipated purchases of wholesale natural gas. At Dec. 31, 2004 and 2003, a change in commodity prices would not have a material impact on earnings for Tampa Electric or PGS.

**Unregulated Companies**

Most of the unregulated subsidiaries at TECO Energy are subject to significant commodity risk. These include TECO Coal, TECO Transport, and TWG. The unregulated companies do not speculate using derivative instruments. However, not all derivative instruments receive hedge accounting treatment due to the strict requirements and narrow applicability of the accounting rules to dynamic transactions.

TECO Coal is exposed to commodity price risk through coal sales as a part of its daily operations. Where possible and economical, TECO Coal enters into fixed price sales transactions to mitigate variability in coal prices. Based on the uncontracted tons subject to market price variation at Dec. 31, 2004 and 2003, a hypothetical 10% increase in the average annual market price of coal for each year would have resulted in an increase in pretax earnings of approximately $1 million in both years.

TECO Coal is also indirectly exposed to changes in the price of crude oil. Under the rules governing Section 29 tax credits, those credits can be phased out in the event that the price of crude oil (as defined by a government price survey) reaches a threshold. The benchmark crude oil prices corresponding to the beginning and end of the tax credit phase-out are estimated for 2005 to be $52 and $65 per barrel, respectively, which are the equivalent of $55 and $68 per barrel on NYMEX (see the **TECO Coal** section). In the event that crude oil prices reach the top of this band, the pretax earnings impact is estimated at approximately $65 million. To hedge this risk, we have entered into a series of derivative transactions that remove approximately 35% of this exposure for 2005.

Commodity price risk exists at TECO Transport as a result of periodic purchases of fuel oil. Haulage and freight agreements often include fuel price adjustments to transfer the risk of market fuel price movements to the customer. TECO Transport also utilizes derivative instruments to reduce the risk of price variability for anticipated fuel purchases in excess of purchases subject to fuel adjustment clauses. As of Dec. 31, 2004, substantially all of the projected fuel price risk for 2005 was removed via price adjustment clauses and derivative instruments. As a result, a hypothetical 10% increase in the price of fuel would not result in a material impact on pretax earnings as of Dec. 31, 2005.

For TWG-Merchant, results of operations are impacted primarily by changes in the market prices for electricity and natural gas. The profitability of merchant power plants is defined by a concept known as "spark spread." The variable cost of producing electricity is primarily a function of gas commodity prices and the heat rate of the plant. The heat rate is the measure of efficiency in converting the input fuel into electricity. When the conversion price equals the market price, the spark spread would be zero. A power plant operating at this level would theoretically break even with respect to variable costs.

Spark spreads are influenced by many factors and are highly variable. TWG-Merchant uses derivative instruments to reduce the commodity price risk exposure of the merchant plants. The commodity price risk of each plant is managed on both a portfolio and asset-specific basis.

The following tables summarize the changes in and the fair value balances of energy derivative assets (liabilities) for the year ended Dec. 31, 2004:

| Changes in Fair Value of Energy Derivatives (millions) | | |
|---|---|---|
| Net fair value of energy derivatives as of Dec. 31, 2003 | $ | 9.1 |
| Net change in unrealized fair value of derivatives | | (6.1) |
| Changes in valuation techniques and assumptions | | – |
| Realized net settlement of derivatives | | (11.8) |
| Net fair value of energy derivatives as of Dec. 31, 2004 | $ | (8.8) |

| Roll-Forward of Energy Derivative Net Assets (Liabilities) (millions) | |
|---|---|
| Total energy derivative net assets (liabilities) as of Dec. 31, 2003 | $ 9.1 |
| Change in fair value of net derivative assets (liabilities): | |
| Recorded in OCI | (9.6) |
| Recorded in earnings | (37.5) |
| Net option premium payments | 30.3 |
| Net purchase (sale) of existing contracts | (1.1) |
| Net fair value of energy derivatives as of Dec. 31, 2004 | $ (8.8) |

When available, the company uses quoted market prices to record the fair value of energy derivative contracts. However, many energy derivative contracts are not traded in sufficient volume or with sufficient market transparency to establish a representative quotation. In those cases, we use industry-accepted valuation techniques based on pricing models or matrix pricing for energy derivative contracts. Prices, inputs, assumptions and the results of valuation techniques are validated by the Middle Office, independently of the Front Office, on a daily basis. Significant inputs and assumptions used by the company to determine the fair value of energy derivative contracts are: 1) the physical delivery location of the commodity; 2) the correlation between different basis points and/or different commodities; 3) rational, economic behavior in the markets and by counterparties; 4) on- and off-peak curve shapes and correlations; 5) observed market information; and 6) volatility forecasts and estimates for and between commodities. Mathematical approaches are applied on a frequent basis to validate and corroborate the results of valuation calculations.

For all unrealized energy derivative contracts, the valuation is an estimate based on the best available information. Actual cash flows could be materially different from the estimated value upon maturity.

The following is a summary table of sources of fair value, by maturity period, for energy derivative contracts at Dec. 31, 2004.

**Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2004**

| *(millions)* | *Current* | *Non-current* | *Total Fair Value* |
|---|---|---|---|
| Source of fair value (millions) | | | |
| Actively quoted prices | $ – | $ – | $ – |
| Other external sources [1] | (8.6) | (0.5) | (9.1) |
| Model prices [2] | 0.3 | – | 0.3 |
| Total | $ (8.3) | $ (0.5) | $ (8.8) |

(1) Information from external sources includes information obtained from OTC brokers, industry price services or surveys and multiple-party on-line platforms.

(2) Model prices are used for determining the fair value of energy derivatives where price quotes are infrequent or the market is illiquid. Significant inputs to the models are derived from market observable data and actual historical experience.

## Other Items Impacting Net Income

**2004 Items**

In 2004, our results from continuing operations included $555.6 million of charges and gains related primarily to valuation adjustments on merchant power assets, refinancing costs and the associated taxes on the cash repatriated from the San José Power Station in Guatemala, the gain on the sale of our interest in our propane business, corporate restructuring charges, and tax credit true-ups (see the **Results Summary** section).

**2003 Items**

In 2003, our results from continuing operations included $118.9 million of charges and gains related to valuation adjustments, project cancellation costs, turbine valuation adjustments, tax credit reversals, and corporate restructuring at the various operating companies and $42.9 million related to the sale of HPP and its operating net income through the date of the sale (see the **Results Summary** section). In addition, we recognized $1.1 million in after-tax charges related to a change in accounting principle for the implementation of FAS 143, *Accounting for Asset Retirement Obligations*, and a $3.2 million after-tax charge for the implementation FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity.*

**2002 Items**

In 2002, our results included a $3.0 million after-tax charge at TECO Investments related to an aircraft leased to US Airways, which filed for bankruptcy. Results at TWG included a $5.8 million after-tax asset valuation charge for the sale of its interests in generating facilities in the Czech Republic. Results at TECO Energy included a $34.1 million pretax ($20.9 million after-tax) charge related to a debt refinancing.

## Other Income (Expense)

In 2004, Other income (expense) of $29.7 million reflects the income related to the gain on the sale of the Hamakua Power Station, the sale of our interest in the propane business and the per-ton installment sale of the 90% interest in the synthetic fuel production facilities at TECO Coal.

Results in 2003 included the gain on the final installment of the sale of TECO Coalbed Methane, the sale of Hardee Power Partners, and the sale of 49.5% interest in the synthetic fuel production facilities partially offset by an arbitration reserve established for TMDP, the indirect owner of the Commonwealth Chesapeake Power Station.

In 2002, Other income (expense) of $15.6 million included $60.7 million from construction related and loan agreements with Panda Energy and earnings on the equity investment in EEGSA at TWG, and income from the investment in TECO Propane Ventures, partially offset by the $9.4 million pretax ($5.8 million after-tax) asset valuation charge for TWG's sale of its minority interest in generating facilities in the Czech Republic and a $34.1 million pretax ($20.9 million after-tax) charge related to a TECO Energy debt refinancing completed in 2002.

AFUDC equity at Tampa Electric, which is included in Other income (expense), was $0.7 million in 2004, $19.8 million in 2003 and $24.9 million in 2002. AFUDC is expected to remain a minimal amount in 2005, but increase slightly in 2006 due to the installation of NOx control at the Big Bend Station at Tampa Electric (see the **Environmental Compliance** section).

Earnings from equity investments (which is included in Other income) include a $45.5 million benefit from the Guatemalan operations included in the Other Unregulated Companies, partially offset by a $9.2 million loss from the TIE projects prior to their sale in July.

## Interest Charges

Total Interest charges were $321.6 million in 2004, compared to $318.0 million in 2003 and $169.3 million in 2002. Interest expense in 2004 reflects no capitalized interest and the effect of debt issues in mid-2003, largely offset by the early settlement of the trust preferred securities, lower cost of short-term borrowings, the deconsolidation of the Guatemalan power facilities, and the sale of Hardee Power Partners. In 2003, capitalized interest on the debt of TECO Energy was $17.3 million and capitalized interest (AFUDC-borrowed funds) at Tampa Electric was $7.6 million. Capitalization of interest ended with commercial operation of the final phase of the Gila River Power Station in July 2003 and the Bayside Power Station in January 2004.

Interest expense increased in 2003 reflecting higher debt balances at both Tampa Electric and TECO Energy associated with the completion of major construction programs. In addition, capitalized interest was $45 million lower in 2003 than in 2002 as a result of the completion of the Union and Gila River construction and the suspension of construction of Dell and McAdams.

## Income Taxes

Income taxes decreased in 2004 as we incurred net operating losses primarily as a result of losses on the disposition of merchant power generating assets. Income tax decreased in 2003, as the result of a loss from continuing operations, continuing non-taxable AFUDC equity, and substantial tax credits associated with the production of non-conventional fuels. Income tax expense as a percentage of income from continuing operations before taxes was 39.6% in 2004, 307.1% in 2003 and (26.9%) in 2002. In 2005, we expect the effective tax rate to be in the range of 30% to 35%.

The cash payment for income taxes, as required by the Alternative Minimum Tax Rules (AMT), state income taxes and payments related to prior years' audits was $22.4 million, $58.8 million and $71.9 million in 2004, 2003 and 2002, respectively.

Due to the generation of deferred income tax assets related to the net operating loss (NOL) carryforward from the disposition of the merchant generating assets and the additional NOL that we expect to generate upon the disposition of the Union and Gila River projects, we expect future cash tax payments for income taxes to be limited to approximately 10% of the AMT rate and various state taxes. We currently expect to utilize these NOL through 2010. Beyond 2010, we expect to use the more than $200 million of AMT carryforward to limit future cash tax payments for federal income taxes to the level of AMT. Our current projection of cash income tax payments in 2005 is about $35 million, including amounts for payments related to the prior year's audit. For the 2006-2009 period, we estimate this amount to be approximately $10 million annually.

Total income tax expense in years prior to 2004 was reduced by the federal tax credits related to the production of non-conventional fuels under Section 29 of the Internal Revenue Code. The recognized tax credit totaled $73.0 million in 2003 and $107.3 million in 2002. These tax credits are generated annually on qualified production at TECO Coal through Dec. 31, 2007, subject to changes in law, regulation or administration that could impact the qualification of Section 29 tax credits. We were unable to utilize any Section 29 tax credits in 2004 due to our net tax loss position for the year and expect to be unable to utilize Section 29 tax credits through 2007, when the tax credit expires (see the **TECO Coal** section).

The tax credit is determined annually and is estimated to be $1.12 per million Btu for 2004, $1.10 per million Btu in 2003 and $1.09 per million Btu in 2002. This rate escalates with inflation but could be limited by domestic oil prices. In 2004, domestic oil prices, as measured by a DOE index, would have had to exceed $51 per barrel for this limitation to have been effective. If the oil price limitation is reached, the level of the tax credits starts to decline. In 2004, it was estimated that the tax credit would have been eliminated at an average oil price of $64 per barrel. The DOE index is based on the "Domestic First Purchase Prices" not the NYMEX quoted oil futures prices and typically averages $3.00 per barrel less than the NYMEX price. The 2004 oil price limits are the equivalent to $54 and $67 per barrel on NYMEX.

In 2004, 2003, and 2002, the decreased income tax expense also reflected the impact of increased overseas operations with deferred U.S. tax structures. The decrease related to these deferrals was $10.5 million, $12.3 million and $8.1 million for 2004, 2003, and 2002, respectively.

The income tax effect of gains and losses from discontinued operations is shown as a component of results from discontinued operations.

## *Discontinued Operations*

**Discontinued Operations**

| *(millions)* | *2004* | *2003* | *2002* |
|---|---|---|---|
| Union & Gila River operations | $ **(96.0)** | $ (61.9) | $ 16.8 |
| Union & Gila River write-off | – | (762.0) | – |
| Union & Gila River joint venture termination | – | (94.7) | – |
| Frontera goodwill write-off | – | (44.9) | – |
| Frontera write-off | **(25.6)** | – | – |
| Frontera operations | **(5.8)** | (3.0) | 7.8 |
| TECO Solutions / other | **(20.3)** | (23.1) | 5.6 |
| TECO Coalbed Methane | – | 22.8 | 31.4 |
| Total discontinued operations | **$ (147.7)** | $(966.8) | $ 61.6 |

The net loss from discontinued operations for 2004 was $147.7 million. Discontinued operations in 2004 reflect the operating losses for the Union and Gila River power stations, the write-off and losses from operations at the Frontera Power Station, and the write-offs and losses from operations associated with certain TECO Solutions companies that are now reported in discontinued operations.

Discontinued operations in 2003 included the write-off of the investment and the operating results from the Union and Gila River power stations; operating results from Prior Energy, which was sold in March 2004; and the gain on the final installment of the sale of the coalbed methane gas production assets in January 2003.

## *Inflation*

The effects of inflation on our results have not been significant for the past several years. The annual rate of inflation, as measured by the Consumer Price Index (CPI), all items, all urban consumers as reported by the U.S. Department of Labor, was 2.7%, 2.3% and 1.6% in 2004, 2003 and 2002, respectively. Published forecasts by economists and by several agencies of the U.S. government indicate that inflation is expected to be relatively modest again in 2005 with a 2.5% increase expected.

Prices for certain products and services used by TECO Energy's operating companies increased at rates above the CPI in 2004, including prices for steel products and petroleum-based products used extensively in all of our operating companies, and for subcontracted mining services used by TECO Coal, and these prices are expected to continue to rise in 2005. In the case of TECO Transport, a portion of the increased cost of petroleum products is passed through to its customers through contract fuel adjustment clauses, and Tampa Electric and PGS recover the cost of commodity fuel through the respective FPSC approved fuel adjustment clauses. In those cases where the higher costs can not be passed directly to the customers, higher costs could reduce the profit margins at the operating companies.

## *Environmental Compliance*

**Consent Decree**

Tampa Electric, in cooperation with the Environmental Protection Agency (EPA) and the U.S. Department of Justice, signed a Consent Decree which became effective Oct. 5, 2000, and a Consent Final Judgment with the Florida Department of Environmental Protection (FDEP) on Dec. 7, 1999. Pursuant to these agreements, allegations of violations of New Source Review requirements of the Clean Air Act were resolved, provision was made for environmental controls and pollution reductions, and Tampa Electric began implementing a comprehensive program to dramatically decrease emissions from its power plants.

The emission reduction requirements included specific detail with respect to the availability of flue gas desulfurization systems (scrubbers) to help reduce sulfur dioxide (SO2), projects for nitrogen oxides (NOx) reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Station to natural gas. The commercial operation dates for the two repowered Bayside units were Apr. 24, 2003 and Jan. 15, 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of natural gas-fueled electric generation.

In 2004, Tampa Electric decided to install selective catalytic reduction (SCR) for NOx control on Big Bend Unit 4, with an expected in-service date by June 1, 2007. Tampa Electric has also decided to install SCRs on Big Bend Units 1, 2 and 3 with in-service dates for Unit 3 by May 1, 2008, Unit 2 by May 1, 2009 and Unit 1 by May 1, 2010. Tampa Electric has begun the detailed engineering and design of the SCR system. Tampa Electric's capital investment forecast includes amounts in the 2005 through 2009 period for compliance with the NOx, SO2 and particulate matter reduction requirements (see the **Capital Investments** section).

The FPSC has determined that it is appropriate for Tampa Electric to recover the operating costs of and earn a return on the investment in the first SCR to be installed at the Big Bend Power Station and pre-SCR projects on Big Bend units 1–3 (which are plant improvements to reduce NOx emissions prior to installing the SCRs) through the Environmental Cost Recovery Clause (ECRC) (see the **Regulation** section). The first SCR (Big Bend Unit 4) is scheduled to enter service by June 1, 2007 and cost recovery, which is dependent on filings to be made in 2007, is expected to start in 2008.

**Emission Reductions**

Projects committed to under the Consent Decree and Consent Final Judgment will result in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO2, NOx and particulate matter (PM) from its facilities by 161,642 tons, 39,066 tons, and 9,285 tons, respectively.

Reductions in SO2 emissions were accomplished through the installation of scrubber systems on Big Bend Units 1 and 2 in 1999. Big Bend Unit 4 was originally constructed with a scrubber. The Big Bend Unit 4 scrubber system was modified in 1994 to allow it to scrub emissions from Big Bend Unit 3 as well. Currently the scrubbers at Big Bend Station remove more than 95% of the SO2 emissions from the flue gas streams.

The repowering of Gannon Station to Bayside Power Station in April 2003 (Bayside Unit 1) and January 2004 (Bayside Unit 2) has resulted in a significant reduction in emissions of all pollutant types. Tampa Electric's decision to install additional NOx emissions controls on all Big Bend units will result in the further reduction of emissions. By 2010, the SCR projects will result in the phased reduction of NOx by 59,652 tons per year from 1998 levels. In total, Tampa Electric's emission reduction initiatives will result in the reduction of SO2, NOx and PM emissions by 89%, 87%, and 70%, respectively, below 1998 levels. With these improvements in place, Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in the community. Due to pollution control co-benefits from the Consent Final Judgment and Consent Decree, reductions in mercury emissions have occurred due to the repowering of Gannon Station to Bayside Station. At Bayside, where mercury levels have decreased 99% below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions are also anticipated from the installation of NOx controls at Big Bend Station, which would lead to a mercury removal efficiency of approximately 70%.

The repowering of Gannon Station to Bayside will also lead to a significant reduction in carbon dioxide (CO2) emissions. It is expected that in 2005, the repowering will result in a decrease in CO2 emissions of approximately 5.2 million tons below 1998 levels. With this reduction, the Tampa Electric system CO2 emissions will be in line with its 1990 CO2 emission levels. As a result of all its already completed emission reduction actions, and upon completion of the SCR projects, Tampa Electric will have achieved emission reduction levels called for in Clean Air Act proposals including the Bush administration's "Clear Skies" proposal.

**Superfund and Former Manufactured Gas Plant Sites**

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2004, Tampa Electric Company has estimated its ultimate financial liability to be approximately $17 million, and this amount has been reflected in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices. The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors or Tampa Electric Company's experience with similar work, adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other PRPs is based on each parties' relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered credit worthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These additional costs would be eligible for recovery through customer rates.

## *Regulation*

**Tampa Electric Rate Strategy**

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75%, with a midpoint of 11.75%, are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue earning within its allowed ROE range even with the rate base additions associated with the repowering of Bayside. Tampa Electric has not sought a base rate increase to recover the investment in Bayside.

**Cost Recovery Clauses – Tampa Electric**

In September 2004, Tampa Electric filed with the FPSC for approval of cost recovery rates for fuel and purchased power, capacity, environmental and conservation costs for the period January through December 2005. In November, the FPSC approved Tampa Electric's requested changes. The rates include the impacts of increased natural gas and coal prices, the collection of $30.9 million for underestimated 2003 & 2004 fuel expenses, the proceeds from the sale of SO2 emissions allowances associated with Hookers Point Station and the O&M costs associated with the Big Bend units 1–3 pre-SCR projects required by the EPA Consent Decree and FDEP Consent Final Judgment (see the **Environmental Compliance** section). In addition, the rates also reflect the FPSC's September 2004 decision to reduce the annual cost recovery amount for water transportation services for coal and petroleum coke provided under Tampa Electric's contract with TECO Transport Company discussed below. Accordingly, Tampa Electric's residential customer rate per 1,000 kilowatt-hours decreased $0.94 from $99.01 in 2004 to $98.07 in 2005.

In October 2004, the FPSC determined that it was appropriate for Tampa Electric to recover through the ECRC the operating costs of and earn a return on the investment in the SCR to be installed on Big Bend Unit 4 for NOx control in compliance with the environmental consent decree. The SCR is scheduled to enter service by Jun. 1, 2007 and cost recovery, which is dependent on filings to be made in 2007, is expected to start in 2008.

**Coal Transportation Contract**

Tampa Electric's contract for coal transportation and storage services with TECO Transport expired on Dec. 31, 2003. TECO Transport had been providing river and cross-gulf transportation services and storage services under that contract since 1999, and under a series of contracts for more than 40 years. Following a Request For Proposal (RFP) process, Tampa Electric executed a new five-year contract with TECO Transport, effective Jan. 1, 2004, for waterborne coal transportation and storage services at market rates supported by the results of the RFP and an independent expert in maritime transportation matters. The prudence of the RFP process and final contract were originally scheduled to be reviewed by the FPSC in the course of the normal fuel cost recovery hearings in November 2003. The hearing was deferred due to protests from other parties seeking more time to evaluate the contract information.

Three days of hearings were held in late May and early June of 2004 and a final order on the matter issued in October 2004. The order reduced the annual amount Tampa Electric can recover from its customers through the fuel adjustment clause for the water transportation services for coal and petroleum coke provided by TECO Transport. The annual after-tax disallowance is estimated to be $8 million to $10 million, depending on the volumes and origination points of the coal shipments, for as long as the contract is in effect. The order neither required Tampa Electric to rebid nor prohibit Tampa Electric from rebidding the contract, which expires Dec. 31, 2008.

In October 2004, Tampa Electric filed a motion for clarification and reconsideration of the order. In the motion, Tampa Electric stated that the FPSC had failed to take into account information that was available that could have changed the outcome. Had the FPSC considered all of the relevant facts, including the rate approved for Progress Energy Florida's waterborne transportation needs, Tampa Electric believes that the FPSC would have arrived at a rate that is comparable to the contract rate. Tampa Electric also asked the FPSC for clarification on the ruling specifically regarding the bidding guidelines provided in the order and the FPSC process associated with the rebidding.

On Mar. 1, 2005, the FPSC heard oral arguments on the motion and denied Tampa Electric's request for reconsideration and clarification. Although the commission's order will not contain clarifying language, through extended commission discussion, it was clear to Tampa Electric that if it decided to rebid waterborne transportation services and if it followed bid procedures approved by the FPSC, the results would likely be deemed appropriate for full cost recovery.

**Storm Damage Cost Recovery**

Following Hurricane Andrew in 1992, Florida's investor owned utilities (IOUs) were unable to obtain transmission and distribution insurance coverage for hurricanes, tornados or other damage due to destructive acts of nature. Tampa Electric and other IOUs were permitted to implement a self-insurance program effective Jan. 1, 1994 for such costs of restoration, and the FPSC authorized Tampa Electric to accrue $4 million annually to grow its unfunded storm damage reserve. Tampa Electric had never utilized its reserve before the 2004 hurricane season and would have had a reserve balance of $44 million at Dec. 31, 2004.

The costs for restoration associated with hurricanes Charley, Frances and Jeanne were estimated to be $72 million at Dec. 31, 2004, which exceeded the storm damage reserve by $28 million. These costs were charged against the storm damage reserve and therefore did not reduce earnings but did reduce cash flow from operations.

Tampa Electric filed for and received approval from the FPSC to defer prudently incurred storm damage restoration costs to the reserve until alternative accounting treatment is sought. At this time Tampa Electric is evaluating several options based upon recent FPSC actions taken with other Florida IOUs that have already filed for recovery of storm damage costs.

**Cost Recovery Clauses – Peoples Gas**

In November 2004, the FPSC approved rates under Peoples' Gas Purchased Gas Adjustment (PGA) for the period January 2005 through December 2005 for the recovery of the costs of natural gas purchased for its distribution customers. The PGA is a factor that can vary monthly due to changes in actual fuel costs but is not anticipated to exceed the annual cap.

**Utility Competition – Electric**

Tampa Electric's retail electric business is substantially free from direct competition with other electric utilities, municipalities and public agencies. At the present time, the principal form of competition at the retail level consists of self-generation available to larger users of electric energy. Such users may seek to expand their alternatives through various initiatives, including legislative and/or regulatory changes that would permit competition at the retail level. Tampa Electric intends to retain and expand its retail business by managing costs and providing high quality service to retail customers.

Presently there is competition in Florida's wholesale power markets, increasing largely as a result of the Energy Policy Act of 1992 and related federal initiatives. However, the state's Power Plant Siting Act, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 megawatts or more, requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits.

In 2003, the FPSC implemented rules modifying rules from 1994 that required IOUs to issue RFPs prior to filing a petition for Determination of Need for construction of a power plant with a steam cycle greater than 75 megawatts. The modified rules provide a mechanism for expedited dispute resolution, allow bidders to submit new bids whenever the IOU revises its cost estimates for its self-build option, require IOUs to disclose the methodology and criteria to be used to evaluate the bids, and provide more stringent standards for the IOUs to recover cost overruns in the event the self-build option is deemed the most cost-effective. The new rules became effective prospectively for requests for proposal for applicable capacity additions.

**FERC Market Power Test**

In November 2004, Tampa Electric and the market-based rate authorized entities within TECO Energy filed a triennial market power study update. On Mar. 2, 2005, after a review of that filing and supporting information, the FERC determined that Tampa Electric had failed certain tests for market power within certain regions of Florida. The FERC has instituted an investigation of Tampa Electric's potential market power in those regions and ordered that Tampa Electric make a compliance filing to determine if Tampa Electric has market power in other regions of the state. If it is determined that Tampa Electric has market power in those regions in question, Tampa Electric could loose its market-based rate authorization for only those regions, and therefore make wholesale power sales at cost-based rates rather than market-based rates. Tampa Electric intends to comply with all of the filing requirements and is evaluating the appropriate response to the FERC's actions.

**Regional Transmission Organization (RTO)**

In December 1999, the FERC issued Order No. 2000, dealing with its continuing effort to effect open access to transmission facilities in large regional markets. In response, the peninsular Florida IOUs (Florida Power & Light, Progress Energy Florida and Tampa Electric) agreed to form an RTO to be known as GridFlorida LLC which would independently control the transmission assets of the filing utilities, as well as other utilities in the region that chose to join. In March 2001, the FERC conditionally approved GridFlorida.

Following challenges to the proposed structure by the FPSC in 2001 and subsequent modification of the plans by the three filing utilities, including modifying the proposal to develop a non-transmission owning RTO model, the FPSC voted to approve many of the compliance changes submitted in August 2002. The process was again delayed in 2002 when the Office of Public Counsel (OPC) filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the IOUs and, by approving GridFlorida, they were doing just that. The Florida Supreme Court dismissed the OPC appeal in May 2003, citing that it was premature because certain portions of the FPSC GridFlorida order are not final.

Following a September 2003 joint meeting of the FERC and FPSC to discuss wholesale market and RTO issues related to GridFlorida and in particular federal/state interactions, deliberations by the FPSC were put on hold in 2004 to allow a consulting firm, engaged by the GridFlorida applicants, to conduct a cost/benefit study of the GridFlorida RTO. As a result, the FPSC held a series of collaborative meetings during the year with all interested parties to facilitate the development of the study methodology as well as participate in the submission of data required to complete the study. Upon conclusion of the study, which is expected to occur in the second quarter of 2005, the study results will be presented to the FPSC. The FPSC is then expected to make a determination as to whether to set the remaining items for hearing or to require the Florida IOUs to take other actions.

**Peoples Gas 2002 Rate Proceeding**

On Jun. 27, 2002, PGS filed a petition with the FPSC to increase its service rates. The requested rates would have resulted in a $22.6 million annual base revenue increase, reflecting a ROE midpoint of 11.75%.

PGS agreed to a settlement with all parties involved, and a final FPSC order was granted on Dec. 17, 2002. PGS received authorization to increase annual base revenues by $12.05 million. The new rates provide an allowed ROE range from 10.25% to 12.25% with an 11.25% midpoint, and a capital structure with 57.43% equity and were effective after Jan. 16, 2003.

**Utility Competition – Gas**

Although PGS is not in direct competition with any other regulated distributors of natural gas for customers within its service areas, there are other forms of competition. At the present time, the principal form of competition for residential and small commercial customers is from companies providing other sources of energy, including electricity.

In Florida, gas service is unbundled for all non-residential customers. In November 2000, PGS implemented its "NaturalChoice" program offering unbundled transportation service to all eligible customers. This means that non-residential customers can purchase commodity gas from a third party but continue to pay PGS for the transportation of the gas.

Competition is most prevalent in the large commercial and industrial markets. In recent years, these classes of customers have been targeted by companies seeking to sell gas directly, by transporting gas through other facilities and thereby bypassing PGS facilities. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates.

In general, PGS faces competition from other energy source suppliers offering fuel oil, electricity and, in some cases, propane. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

## *Corporate Governance*

In the last several years, the U.S. Congress, the U.S. Securities and Exchange Commission (SEC), the New York Stock Exchange (NYSE), and other interested groups have focused extensively on improving corporate accountability and corporate governance in an effort to restore investor confidence. The rules passed by the SEC and the listing standards adopted by the NYSE require, among other things, independence by the Board of Directors and various Board committees, a statement of governance guidelines and detailed committee charters, an internal audit function, a code of ethics for the CEO, senior financial officers and directors, adequate internal controls to detect fraud, increased oversight of financial disclosure by the Audit Committee, and certification by the CEO and CFO of the financial results.

The corporate culture of TECO Energy is based on integrity and sound business ethics. We have longstanding policies and practices that are designed to provide the framework for the ethical operation of the company, protect the shareholders' interests, and ensure compliance with the law and requirements of the NYSE. For many years, the vast majority of our Board of Directors have been independent, and the required independent Board committees have been in place. In addition, we have had a rigorous internal audit and compliance function, including an anonymous reporting system which now has been expanded to cover matters required to be disclosed to the Audit Committee and the non-management directors, and a code of ethics for all employees and officers, called the Standards of Integrity. The code was expanded in 2002 to include directors and is posted on the company's website. In addition, to ensure that our vendors are aware of our expectation that they conduct their business in an ethical and professional manner, we require that they comply, as we do, with the Principles and Standards of Ethical Supply Management Conduct published by the Institute for Supply Management.

At TECO Energy, we are committed to integrity and transparency in our financial reporting. Our existing controls and procedures for full and complete financial reporting and disclosure have been formalized into a comprehensive system of checks and balances that are reviewed quarterly for effectiveness. The CEO and CFO have filed with the SEC, as required by law, sworn statements certifying without exception the accuracy of the financial statements each quarter, and the annual certification is filed as an exhibit to our Annual Report on Form 10-K. Additionally, the CEO has signed and filed with the NYSE all of the required certifications as to compliance with the NYSE's corporate governance listing standards.

The Board of Directors operates under a set of guidelines that clearly establish the Board's responsibilities, and each committee has a charter that defines its purpose, duties and responsibilities. The Corporate Governance Guidelines and the committee charters are reviewed regularly to ensure that they comply with all of the relevant regulations and meet the needs of the Board. More information about the members of the Board of Directors, as well as copies of the Corporate Governance Guidelines, the various committee charters, and the Standards of Integrity, can be found in the corporate governance section of the Investor Relations page on our website, **www.tecoenergy.com.**

## *Internal Controls*

Compliance with Section 404 of the Sarbanes-Oxley Act of 2002 (SOX 404) and related rules of the Securities and Exchange Commission require management of public companies to assess the effectiveness of the company's internal controls over financial reporting as of the end of each fiscal year. This includes disclosure of any material weaknesses in the company's internal controls over financial reporting that have been identified by management. In addition, SOX 404 requires the company's independent auditor to attest to and report on management's annual assessment of the company's internal controls over financial reporting. We have documented, tested and assessed our systems of internal control over financial reporting, as required under SOX 404 and Public Company Accounting Oversight Board Auditing Standard No. 2, *An Audit of Internal Control Over Financial Reporting Performed in Conjunction With An Audit of Financial Statements* (Standard No. 2), which was adopted in June 2004, to provide the basis for management's report and our independent auditor's attestation on the effectiveness of our internal control over financial reporting as of December 31, 2004. We estimate our SOX 404 compliance costs in 2004 were approximately $6.3 million, which include $4.0 million of external costs.

There are three levels of possible deficiencies in our internal controls over financial reporting that can be identified during our assessment phase, which are:

- an internal control deficiency, which exists when the design or the operation of a control does not allow management or employees, in the normal course of performing their functions, to prevent or detect misstatements on a timely basis;
- a significant deficiency, which exists when an internal control deficiency or a combination of internal controls deficiencies adversely affects our ability to initiate, authorize, record, process or report financial data in accordance with GAAP such that there is a more than remote likelihood that a misstatement of the annual or interim financial statements that is more than inconsequential will not be prevented or detected; and
- a material weakness, which exists when a significant deficiency or a combination of significant deficiencies results in a more than remote likelihood that a material misstatement of the annual or interim financial statements will not be prevented or detected.

As a result, our assessment could result in two possible outcomes at our reporting date:

- we could conclude that our internal controls over financial reporting were designed and were operating effectively, or
- we could conclude that our internal controls over financial reporting were not properly designed or did not operate

effectively. A material weakness that exists at the reporting date would require our assessment to be that our internal controls over financial reporting are not effective, and we would be required to disclose such material weaknesses.

Our independent auditor is now required to issue three opinions annually, beginning with our 2004 consolidated financial statements. First, the auditor must evaluate and opine regarding the process by which we assessed the effectiveness of our internal controls over financial reporting. A second opinion must be issued as to the effectiveness of our internal controls over financial reporting. Finally, as in the past, the independent auditor must issue an opinion, as to whether our consolidated financial statements are fairly presented in all material respects.

The scope of our assessment of our internal controls over financial reporting included all of our consolidated entities. We have completed the assessment of the effectiveness on our internal controls over financial reporting as of Dec. 31, 2004, and have concluded that our controls are operating effectively.

## *Transactions with Related and Certain Other Parties*

We have interests in unconsolidated affiliates, which are discussed in the **Other Unregulated Companies** and **Off-Balance Sheet Financing** sections.

In October 2003, Tampa Electric signed a five-year contract renewal with an affiliate company, TECO Transport Corporation, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract calls for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008 (see the **Tampa Electric** and **Regulation** sections).

## *Non-GAAP Presentation*

Many times in this Managements Discussion and Analysis of Financial Condition and Results of Operations, we present non-GAAP results which present financial results after elimination of the effects of certain identified gains and charges. We believe that the presentation of this non-GAAP financial performance provides investors a measure that reflects the company's operations under our business strategy. We also believe that it is helpful to present a non-GAAP measure of performance that clearly reflects the ongoing operations of our business and allows investors to better understand and evaluate the business as it is expected to operate in future periods. Management and the Board of Directors use this non-GAAP presentation as a yardstick for measuring our performance, making decisions that are dependent upon the profitability of our various operating units and in determining levels of incentive compensation.

The non-GAAP measure of financial performance we use is not a measure of performance under accounting principles generally accepted in the United States and should not be considered an alternative to net income or other GAAP figures as an indicator of our financial performance or liquidity. Our non-GAAP presentation of net income may not be comparable to similarly titled measures used by other companies.

While each of the particular excluded items is not expected to recur, there may be true-ups to charges related to merchant power facilities or additional debt extinguishment activities. We recognize that there may be items that could be excluded in the future. Even though charges may occur, we believe the non-GAAP measure is important in addition to GAAP net income for assessing our potential future performance because excluded items are limited to those that we believe are not indicative of future performance.

## *Investment Considerations*

The following are certain factors that could affect TECO Energy's future results. They should be considered in connection with evaluating forward-looking statements made by or on behalf of TECO Energy because these factors could cause actual results and conditions to differ materially from those projected in those forward-looking statements.

**Financing Risks**

**We have substantial indebtedness, which could adversely affect our financial condition and financial flexibility.**

In recent years we have significantly increased our indebtedness, which has resulted in an increase in the amount of fixed charges we are obligated to pay. The level of our indebtedness and restrictive covenants contained in our debt obligations could limit our ability to obtain additional financing or refinance existing debt and could prevent the repayment of subordinated debt and the payment of dividends if those payments would cause a violation of the covenants.

TECO Energy and Tampa Electric must meet certain financial tests as defined in the applicable agreements to use our and its respective bank credit facilities. Also, we, Tampa Electric and other operating companies have certain restrictive covenants in specific agreements and debt instruments. The restrictive covenants of our subsidiaries could limit their ability to make distributions to us, which would further limit our liquidity (see the **Credit Facilities** and **Covenants in Financing Agreements** sections and **Significant Financial Covenants** table in the **Liquidity, Capital Resources** sections).

As of Dec. 31, 2004, we were not in compliance with the EBITDA-to-interest or debt-to-total capital financial covenants in our construction undertakings associated with TWG's Gila River and Union projects, which, absent the pending sale or other transfer of the projects to the lenders, including through the previously announced pre-negotiated Chapter 11 cases filed by the project companies could result in the lenders seeking to accelerate the $1.395 billion of non-recourse construction debt. As of Dec. 31, 2004, we were otherwise in compliance with required financial covenants. We cannot assure you, however, that we will be in compliance with these financial covenants in the future. Our failure to comply with any of these covenants or to meet our payment obligations could result in an event of default which, if not cured or waived, could result in the acceleration of other outstanding debt obligations. We may not have sufficient working capital or liquidity to satisfy our debt obligations in the event of an acceleration of all or a portion of our outstanding obligations. In addition, if we had to defer interest payments on our subordinated notes underlying the outstanding trust preferred securities, we would be prohibited from paying cash dividends on our common stock until all unpaid distributions on those subordinated notes were made.

We also incur obligations in connection with the operations of our subsidiaries and affiliates that do not appear on our balance sheet. These obligations take the form of guarantees, letters of credit and contractual commitments, as described in the sections titled **Liquidity, Capital Resources** and **Off-Balance Sheet Financing.** In addition, our unconsolidated affiliates from time to time incurred non-recourse debt to finance their power projects. Although we are not obligated on that debt, our investments in those unconsolidated affiliates are at risk if the affiliates default on their debt.

**Our financial condition and ability to access capital may be materially adversely affected by further ratings downgrades.**

On July 20, 2004, S&P lowered the ratings on our senior unsecured debt to BB with a stable outlook. It lowered the ratings on other of our securities, as well as those of TECO Finance, including lowering the rating of the trust preferred securities to B. S&P affirmed its rating of Tampa Electric Company's senior secured and unsecured debt at BBB-with a stable outlook. In February 2004, Moody's Investors Service lowered the ratings on our senior unsecured debt to Ba2 with a negative outlook. This followed actions in April 2003, when Moody's and Fitch Ratings lowered their ratings on our senior unsecured debt to Ba1 and BB+, respectively, both with a negative outlook. Tampa Electric Company's senior secured and unsecured debt ratings were lowered to Baa1 and Baa2, respectively, by Moody's and to BBB+ for unsecured debt, by Fitch, with a negative outlook by Moody's. These and any future downgrades may affect our ability to borrow, future collateral, or margin postings and may increase our financing costs, which may decrease our earnings. We are also likely to experience greater interest expense than we may have otherwise if, in future periods, we replace maturing debt with new debt bearing higher interest rates due to our lower credit ratings. In addition, such downgrades could adversely affect our relationships with customers and counterparties.

As a result of past rating actions, TECO EnergySource and other of our subsidiaries were required to post collateral with counterparties to transact in the forward markets for electricity and gas. At Dec. 31, 2004, because of our actions in 2004 to reduce our exposure to additional merchant power and to exit TECO Solutions' businesses, we have minimal exposure to additional calls for collateral. At current ratings, Tampa Electric and PGS are able to purchase gas and electricity without providing collateral. If the ratings of Tampa Electric Company declined to below investment grade, Tampa Electric and Peoples Gas could be required to post collateral to support their purchases of gas and electricity.

**If we are unable to limit capital expenditure levels as forecasted, our financial condition and results could be adversely affected.**

Part of our plans includes capital expenditures at the operating companies at maintenance levels for the next several years. We cannot be sure that we will be successful in limiting capital expenditures to the planned amount. If we are unable to limit capital expenditures to the forecasted levels, we may need to draw on credit facilities, access the capital markets on unfavorable terms or ultimately sell additional assets to improve our financial position. We cannot be sure that we will be able to obtain additional financings or sell such assets, in which case our financial position, earnings and credit ratings could be adversely affected.

**Because we are a holding company, we are dependent on cash flow from our subsidiaries, which may not be available in the amounts and at the times we need it.**

We are a holding company and dependent on cash flow from our subsidiaries to meet our cash requirements that are not satisfied from external funding sources. Some of our subsidiaries have indebtedness containing restrictive covenants which, if violated, would prevent them from making cash distributions to us. In particular, certain long-term debt at PGS prohibits payment of dividends to us if Tampa Electric Company's consolidated shareholders' equity is lower than $500 million. At Dec. 31, 2004, Tampa Electric Company's consolidated shareholders' equity was approximately $1.7 billion. Also, our wholly owned subsidiary, TECO Diversified, Inc., the holding company for TECO Transport, TECO Coal and TECO Solutions, has a guarantee related to a coal supply agreement that could limit the payment of dividends by TECO Diversified to us.

**Various factors could affect our ability to sustain our dividend.**

Our ability to pay a dividend, or sustain it at current levels, could be affected by such factors as the level of our earnings and therefore our dividend payout ratio, and pressures on our liquidity, including unplanned debt repayments, unexpected capital, shortfalls in operating cash flow and negative retained earnings. These are in addition to any restrictions on dividends from our subsidiaries to us discussed above. The Public Utility Holding Company Act of 1935 (PUHCA) restricts the payment of distributions from capital for registered companies. However, we are not subject to such restrictions because we are exempt from registration under PUHCA.

**We are vulnerable to interest rate changes and may not have access to capital at favorable rates, if at all.**

Changes in interest rates and capital markets generally affect our cost of borrowing and access to these markets. We cannot be sure that we will be able to accurately predict the effect those changes will have on our cost of borrowing or access to capital markets.

**Merchant Power Project Risks**

**We and the project companies have not yet completed the transfer of our ownership of the Union and Gila River projects to the lending group.**

Our decision to exit from the ownership of the projects is not conditioned on reaching a consensual agreement with the lenders. If the pre-negotiated Chapter 11 cases of the project companies cannot be concluded as anticipated, there could be a delay in the ultimate forgiveness of the non-recourse debt and there could be a change in the accounting treatment from discontinued operations back to continuing operations in a future period.

The parties have retained the right to assert certain claims they may have against one another until the transfer is completed. Assertion of such claims and defense against them could be time consuming and costly and delay the ultimate disposition of our interest in the projects.

**The remaining operating power plant owned by a subsidiary of TWG-Merchant is affected by market conditions until its sale is completed.**

We have an agreement to sell our interest in the Commonwealth Chesapeake Power Station, and this transaction is expected to close by Mar. 31, 2005. However, this plant currently sells most of its power in the spot market, so we cannot predict with certainty:

- the amount or timing of revenue it may receive from power sales;
- the differential between the cost of operations and power sales revenue;
- the effect of competition from other suppliers of power;
- the demand for power in the market served by the plant relative to available supply; or
- the availability of transmission to accommodate the sale of power.

TWG-Merchant's results could be adversely affected until the time that the sale of this power plant is completed.

**The status of our investments in the suspended Dell and McAdams plants and the Commonwealth Chesapeake Power Station, which is in the process of being sold, is subject to uncertainties which could result in additional impairments.**

Our investment in the Dell and McAdams power plants was written-down to reflect current fair market value as of Dec. 31, 2004 and we are pursuing the sale of these plants. Because the write-off was to estimated fair market value, there is a risk of further impairment should we be unable to sell them or otherwise obtain our estimated market value for them.

Likewise, we have entered into an agreement for the sale of our interest in the Commonwealth Chesapeake Power Station, which we expect to close near Mar. 31, 2005. Should this sale not be completed as planned, we would not receive the expected $86 million cash proceeds from this sale, and additional valuation adjustments could be required.

## General Business and Operational Risks

**General economic conditions may adversely affect our businesses.**

Our businesses are affected by general economic conditions. In particular, the projected growth in Florida and Tampa Electric's service area is important to the realization of Tampa Electric's and PGS' forecasts for annual energy sales growth. An unanticipated downturn in Florida's or the local area's economy could adversely affect Tampa Electric's or PGS' expected performance.

Our unregulated businesses particularly, TECO Transport, TECO Coal and the Guatemalan operations, are also affected by general economic conditions in the industries and geographic areas they serve, both nationally and internationally.

**Potential competitive changes may adversely affect our regulated electricity and gas businesses.**

The U.S. electric power industry has been undergoing restructuring. Competition in wholesale power sales has been introduced on a national level. Some states have mandated or encouraged competition at the retail level and, in some situations, required divestiture of generating assets. While there is active wholesale competition in Florida, the retail electric business has remained substantially free from direct competition. Though not expected in the foreseeable future, changes in the competitive environment occasioned by legislation, regulation, market conditions or initiatives of other electric power providers, particularly with respect to retail competition, could adversely affect Tampa Electric's business and its performance.

The gas distribution industry has been subject to competitive forces for several years. Gas services provided by PGS are now unbundled for all non-residential customers. Because PGS earns margins on distribution of gas but not on the commodity itself, unbundling has not negatively impacted PGS' results. However, future structural changes that we cannot predict could adversely affect PGS.

**Our gas and electricity businesses are highly regulated, and any changes in regulatory structures could lower revenues or increase costs or competition.**

Tampa Electric and PGS operate in highly regulated industries. Their retail operations, including the prices charged, are regulated by the FPSC, and Tampa Electric's wholesale power sales and transmission services are subject to regulation by the FERC. Changes in regulatory requirements or adverse regulatory actions could have an adverse effect on Tampa Electric's or PGS' performance by, for example, increasing competition or costs, threatening investment recovery or impacting rate structure.

**Our businesses are sensitive to variations in weather and have seasonal variations.**

Most of our businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's and PGS' energy sales are particularly sensitive to variations in weather conditions. Those companies forecast energy sales on the basis of normal weather, which represents a long-term historical average. Significant variations from normal weather could have a material impact on energy sales. Unusual weather, such as hurricanes like those experienced in 2004, could adversely affect operating costs and sales and cause damage to our facilities, which may require additional costs to repair.

PGS, which has a typically short but significant winter peak period that is dependent on cold weather, is more weather sensitive than Tampa Electric, which has both summer and winter peak periods. Mild winter weather in Florida can be expected to negatively impact results at PGS.

Variations in weather conditions also affect the demand and prices for the commodities sold by TECO Coal. TECO Transport is also impacted by weather because of its effects on the supply of and demand for the products transported. Severe weather conditions could interrupt or slow service and increase operating costs of those businesses.

**Commodity price changes may affect the operating costs and competitive positions of our businesses.**

Most of our businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes could affect the prices these businesses charge, their operating costs and the competitive position of their products and services.

In the case of Tampa Electric, fuel costs used for generation are affected primarily by the cost of coal and gas. Tampa Electric is able to recover the cost of fuel through retail customers' bills, but increases in fuel costs affect electric prices and, therefore, the competitive position of electricity against other energy sources.

The ability to make sales and the margins earned on wholesale power sales are affected by the cost of fuel to Tampa Electric, particularly as it compares to the costs of other power producers.

In the case of PGS, costs for purchased gas and pipeline capacity are recovered through retail customers' bills, but increases in gas costs affect total retail prices, and therefore, the competitive position of PGS relative to electricity, other forms of energy and other gas suppliers.

**We rely on some transmission and distribution assets that we do not own or control to deliver wholesale electricity, as well as natural gas. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver power and natural gas may be hindered.**

We depend on transmission and distribution facilities owned and operated by utilities and other energy companies to deliver the electricity and natural gas we sell to the wholesale market, as well as the natural gas we purchase for use in our electric generation facilities. If transmission is disrupted, or if capacity is inadequate, our ability to sell and deliver products and satisfy our contractual and service obligations may be hindered.

The FERC has issued regulations that require wholesale electric transmission services to be offered on an open-access, non-discriminatory basis. Although these regulations are designed to encourage competition in wholesale market transactions for electricity, there is the potential that fair and equal access to transmission systems will not be available or that sufficient transmission capacity will not be available to transmit electric power as we desire. We cannot predict the timing of industry changes as a result of these initiatives or the adequacy of transmission facilities. Likewise, unexpected interruption in upstream natural gas supply or transmission could affect our ability to generate power or deliver natural gas to local distribution customers.

**The uncertain outcome regarding the creation of regional transmission organizations, or RTOs, may impact our operations, results or financial condition.**

There continue to be proposals regarding development of RTOs, which would independently control the transmission assets of participating utilities in peninsular Florida. Given the regulatory uncertainty of the ultimate timing, structure and operations of any RTOs or an alternate combined transmission structure, we cannot predict what effect their creation will have on our future operations, results or financial condition.

**We may be unable to take advantage of our existing tax credits, and our earnings from outside investors in the non-conventional fuels production facilities may be impacted by domestic oil prices.**

We derive a portion of our net income from Section 29 tax credits related to the production of non-conventional fuels. Although we have sold more than 90% of our interest in the synthetic fuel production facilities in 2004 and 2005, the amounts we realize from the sales and our continuing operations of the facilities on behalf of the third-party owners are dependent on the continued availability to the purchaser of the tax credits, and our use of any remaining tax credits is dependent on our generating sufficient taxable income against which to use the credits. The availability of the Section 29 tax credits, both to those purchasers and us, could be negatively impacted by administrative actions of the Internal Revenue Service or the U.S. Treasury or changes in law, regulation or administration. In addition, although we have partially hedged against it, the tax credits to the purchasers of our non-conventional fuels production facilities could be limited if annual average domestic oil prices in 2005, as measured by the Department of Energy reference price, exceed an estimated $52 per barrel, which is the equivalent of $55 per barrel on NYMEX, and any such limitation could adversely affect our earnings and cash flows.

**Impairment testing of certain long-lived assets and goodwill could result in impairment charges.**

The company tests its long-lived assets and goodwill for impairment annually or more frequently if certain triggering events occur. Should the current carrying values of any of these assets not be recoverable, the company would incur charges to write down the assets to fair market value.

**Problems with operations could cause us to incur substantial costs.**

Each of our subsidiaries is subject to various operational risks, including accidents, or equipment failures and operations below expected levels of performance or efficiency. As operators of power generation facilities, Tampa Electric and TWG could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes that would result in performance below assumed levels of output or efficiency. Our outlook assumes normal operations and normal maintenance periods for our operating companies' facilities.

**Our international projects and the operations of TECO Transport are subject to risks that could result in losses or increased costs.**

Our other unregulated companies are involved in certain international projects. These projects involve numerous risks that are not present in domestic projects, including expropriation, political instability, currency exchange rate fluctuations, repatriation restrictions, and regulatory and legal uncertainties. The international subsidiaries attempt to manage these risks through a variety of risk mitigation measures, including specific contractual provisions, obtaining non-recourse financing and obtaining political risk insurance where appropriate.

TECO Transport is exposed to operational risks in international ports, primarily due to its need for suitable labor and equipment to safely discharge its cargoes in a timely manner. TECO Transport attempts to manage these risks through a variety of risk mitigation measures, including retaining agents with local knowledge and experience in successfully discharging cargoes and vessels similar to those used by TECO Transport.

**Changes in the environmental laws and regulations affecting our businesses could increase our costs or curtail our activities.**

Our businesses are subject to regulation by various governmental authorities dealing with air, water and other environmental matters. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on us or require us to curtail some of our businesses' activities.

**We are currently defending lawsuits in which we could be liable for damages and responding to an informal inquiry of the SEC.**

A number of securities class action lawsuits were filed in August, September and October 2004 against us and certain of our current and former officers by purchasers of our securities. These suits, which were filed in the U.S. District Court for the Middle District of Florida, allege disclosure violations under the Securities Exchange Act of 1934. These actions were consolidated but remain at the initial pleading stage. In addition, in connection with the previously disclosed SEC informal inquiry resulting from a letter from the former non-equity member in the Commonwealth Chesapeake Project raising issues related to the arbitration proceeding involving that project, the SEC has requested additional information primarily related to the allegations made in these securities class action lawsuits, focusing on various merchant plant investments and related matters.

In March 2001, TWG (under its former name of TECO Power Services Corporation) was served with a lawsuit filed in Hillsborough County Florida, by a Tampa-based firm named Grupo Interamerica, LLC (Grupo) in connection with a potential investment in a power project in Colombia in 1996. Grupo alleged, among other things, that TWG breached an oral contract with Grupo. On Aug. 3, 2004, the trial court granted TWG's motion for summary judgment, leaving only one count remaining in the lawsuit. On Oct. 18, 2004, TWG's motion for summary judgment on the remaining count was granted. The plaintiffs have appealed, and we expect the appellate court to render a decision by the end of 2005.

On Aug. 30, 2004, a Colombian trade union, which was to have been the owner/lessor of the power plant if the transaction had been consummated, filed a demand for arbitration in Colombia pursuant to provisions of a confidentiality and exclusivity agreement (the "confidentiality agreement") between the trade union and a subsidiary of TWG, TPS International Power, Inc., alleging breach of contract and seeking damages in the amount of $48 million. TECO Energy, Inc. and TWG were also named, although those companies were not parties to the confidentiality agreement. This arbitration is being funded by Grupo pursuant to a contract under which Grupo will share in the recovery, if any. The arbitration is in its preliminary stages, and although the respondents have not been served, the arbitrators have been selected by the parties. There is greater uncertainty of the outcome of this proceeding due to the venue and rules of the arbitration being governed by a foreign jurisdiction.

We intend to vigorously defend all of these proceedings. We cannot predict the ultimate resolution of any of these matters at this time, and there can be no assurance that these matters will not have a material adverse impact on our financial condition or results of operations.

From time to time, TECO Energy and its subsidiaries are involved in various other legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with the appropriate accounting rules to provide for matters that are probable of resulting in an estimable, material loss. While we do not believe that the ultimate resolution of pending matters will have a material adverse effect on our results of operations or financial condition, the outcome of such proceedings is uncertain.

## *Consolidated Balance Sheets*

| **Assets**<br>*(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| **Current assets** | | |
| Cash and cash equivalents | **$ 96.7** | $ 108.2 |
| Restricted cash | **57.1** | 51.4 |
| Receivables, less allowance for uncollectibles of $8.0 and $4.5 at Dec. 31, 2004 and 2003, respectively | **286.8** | 280.4 |
| Inventories, at average cost | | |
| Fuel | **46.2** | 88.2 |
| Materials and supplies | **74.6** | 82.5 |
| Current derivative assets | **3.8** | 21.1 |
| Prepayments and other current assets | **43.6** | 68.6 |
| Assets held for sale | **128.8** | 169.4 |
| Total current assets | **737.6** | 869.8 |
| **Property, plant and equipment** | | |
| Utility plant in service | | |
| Electric | **4,857.9** | 5,245.6 |
| Gas | **810.8** | 778.1 |
| Construction work in progress | **207.1** | 1,151.1 |
| Other property | **847.6** | 865.4 |
| Property, plant and equipment, at original cost | **6,723.4** | 8,040.2 |
| Accumulated depreciation | **(2,065.5)** | (2,361.2) |
| Total property, plant and equipment (net) | **4,657.9** | 5,679.0 |
| **Other assets** | | |
| Deferred income taxes | **1,379.1** | 1,051.5 |
| Other investments | **8.0** | 16.5 |
| Regulatory assets | **200.9** | 188.3 |
| Investment in unconsolidated affiliates | **263.0** | 343.5 |
| Goodwill | **59.4** | 71.2 |
| Deferred charges and other assets | **111.5** | 165.1 |
| Assets held for sale | **2,059.1** | 2,077.4 |
| Total other assets | **4,081.0** | 3,913.5 |
| **Total assets** | **$ 9,476.5** | $ 10,462.3 |

| **Liabilities and capital**<br>*(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| **Current liabilities** | | |
| Long-term debt due within one year | | |
| Recourse | **$ 5.5** | $ 6.1 |
| Non-recourse | **8.1** | 25.5 |
| Notes payable | **115.0** | 37.5 |
| Accounts payable | **257.8** | 313.8 |
| Customer deposits | **105.8** | 101.4 |
| Current derivative liabilities | **11.5** | 12.0 |
| Interest accrued | **50.6** | 56.6 |
| Taxes accrued | **36.3** | 149.9 |
| Liabilities associated with assets held for sale | **1,631.8** | 1,544.4 |
| Total current liabilities | **2,222.4** | 2,247.2 |
| **Other liabilities** | | |
| Deferred income taxes | **504.1** | 498.0 |
| Investment tax credits | **20.0** | 22.8 |
| Regulatory liabilities | **539.0** | 560.2 |
| Long-term derivative liability | **0.5** | - |
| Deferred credits and other liabilities | **351.5** | 364.1 |
| Liabilities associated with assets held for sale | **672.2** | 697.8 |
| Long-term debt, less amount due within one year | | |
| Recourse | **3,588.9** | 3,660.3 |
| Non-recourse | **13.4** | 83.2 |
| Junior subordinated | **277.7** | 649.1 |
| Minority interest | **2.9** | 1.9 |
| Total other liabilities | **5,970.2** | 6,537.4 |
| **Commitments and contingencies** (see **Note 12**) | | |
| **Capital** | | |
| Common equity (400 million shares authorized; par value $1; 199.7 million shares and 187.8 million shares outstanding at Dec. 31 2004 and 2003, respectively) | **199.7** | 187.8 |
| Additional paid in capital | **1,489.4** | 1,220.8 |
| Retained earnings (deficit) | **(357.6)** | 339.5 |
| Accumulated other comprehensive income | **(43.8)** | (55.8) |
| Common equity | **1,287.7** | 1,692.3 |
| Unearned compensation | **(3.8)** | (14.6) |
| Total capital | **1,283.9** | 1,677.7 |
| **Total liabilities and capital** | **$ 9,476.5** | $ 10,462.3 |

The accompanying notes are an integral part of the consolidated financial statements.

## Consolidated Statements of Income

| (millions, except per share amounts) For the years ended Dec. 31, | | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| **Revenues** | Regulated electric and gas (includes franchise fees and gross receipts taxes of $83.8 million in 2004, $77.7 million in 2003 and $73.8 million in 2002) | $ 2,101.0 | $ 1,991.1 | $ 1,867.0 |
| | Unregulated | 568.1 | 607.2 | 643.5 |
| | Total revenues | 2,669.1 | 2,598.3 | 2,510.5 |
| **Expenses** | Regulated operations | | | |
| | Fuel | 536.7 | 344.9 | 312.7 |
| | Purchased power | 172.3 | 184.7 | 202.3 |
| | Cost of natural gas sold | 226.2 | 224.0 | 148.9 |
| | Other | 258.2 | 258.4 | 257.2 |
| | Other operations | 605.3 | 619.6 | 579.8 |
| | Maintenance | 140.7 | 145.4 | 160.5 |
| | Depreciation | 282.3 | 319.1 | 296.1 |
| | Asset impairment | 713.5 | 132.9 | – |
| | Goodwill and intangible asset impairment | 4.8 | 32.9 | – |
| | Restructuring charges | 1.2 | 24.6 | 17.8 |
| | Taxes, other than income | 185.0 | 172.5 | 169.9 |
| | Total expenses | 3,126.2 | 2,459.0 | 2,145.2 |
| **(Loss) income from operations** | | (457.1) | 139.3 | 365.3 |
| **Other income (expense)** | Allowance for other funds used during construction | 0.7 | 19.8 | 24.9 |
| | Other income | 144.0 | 112.7 | 19.3 |
| | Loss on debt extinguishment | (4.4) | – | (34.1) |
| | Impairment on TIE investment | (152.3) | – | – |
| | TMDP arbitration reserve | 5.6 | (32.0) | – |
| | Income (loss) from equity investments | 36.1 | (0.4) | 5.5 |
| | Total other income (expense) | 29.7 | 100.1 | 15.6 |
| **Interest charges** | Interest expense | 321.9 | 285.6 | 140.0 |
| | Distribution on preferred securities of subsidiary | – | 40.0 | 38.9 |
| | Allowance for borrowed funds used during construction | (0.3) | (7.6) | (9.6) |
| | Total interest charges | 321.6 | 318.0 | 169.3 |
| **(Loss) income from continuing operations before provision for income taxes** | | (749.0) | (78.6) | 211.6 |
| (Benefit) for income taxes | | (265.1) | (91.5) | (56.9) |
| Net (loss) income from continuing operations before minority interests | | (483.9) | 12.9 | 268.5 |
| Minority interest | | 79.5 | 48.8 | – |
| **Net (loss) income from continuing operations** | | (404.4) | 61.7 | 268.5 |
| **Discontinued operations** | (Loss) income from discontinued operations | (225.1) | (1,514.7) | 74.2 |
| | Income tax (benefit) provision | (77.5) | (547.9) | 12.6 |
| | Total discontinued operations | (147.6) | (966.8) | 61.6 |
| Cumulative effect of change in accounting principle, net of tax | | – | (4.3) | – |
| **Net (loss) income** | | $ (552.0) | $ (909.4) | $ 330.1 |
| **Average common shares outstanding** | | | | |
| | Basic | 192.6 | 179.9 | 153.2 |
| | Diluted | 192.6 | 180.2 | 153.3 |
| **Earnings per share from continuing operations** | | | | |
| | Basic | $ (2.10) | $ 0.34 | $ 1.75 |
| | Diluted | $ (2.10) | $ 0.34 | $ 1.75 |
| **Earnings per share** | | | | |
| | Basic | $ (2.87) | $ (5.05) | $ 2.15 |
| | Diluted | $ (2.87) | $ (5.04) | $ 2.15 |
| Dividends paid per common share outstanding | | $ 0.76 | $ 0.925 | $ 1.41 |

## Consolidated Statements of Comprehensive Income

| (millions) For the years ended Dec. 31, | | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| **Net (loss) income** | | $ (552.0) | $ (909.4) | $ 330.1 |
| **Other comprehensive income (loss), net of tax** | | | | |
| | Foreign currency translation adjustments | – | 1.2 | (1.2) |
| | Net unrealized gains (losses) on cash flow hedges | 4.8 | 28.1 | (13.2) |
| | Minimum pension liability adjustments | 7.2 | (43.9) | (4.4) |
| | Other comprehensive income (loss), net of tax | 12.0 | (14.6) | (18.8) |
| **Comprehensive (loss) income** | | $ (540.0) | $ (924.0) | $ 311.3 |

The accompanying notes are an integral part of the consolidated financial statements.

## *Consolidated Statements of Cash Flows*

| *(millions)* *For the years ended Dec. 31,* | *2004* | *2003* | *2002* |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Net (loss) income | **$ (552.0)** | $ (909.4) | $ 330.1 |
| Adjustments to reconcile net (loss) income to net cash from operating activities: | | | |
| Depreciation | **289.6** | 382.0 | 303.2 |
| Deferred income taxes | **(355.3)** | (709.4) | (96.6) |
| Investment tax credits, net | **(2.9)** | (4.7) | (4.8) |
| Allowance for funds used during construction | **(1.0)** | (27.4) | (34.5) |
| Amortization of unearned compensation | **13.6** | 18.3 | 13.9 |
| Cumulative effect of change in accounting principle, pretax | **–** | 7.1 | – |
| Gain on sales of business/assets, pretax | **(92.9)** | (147.5) | (15.1) |
| Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings | **(34.3)** | 13.8 | 15.3 |
| Minority loss | **(79.5)** | (48.8) | – |
| Asset impairment, pretax | **876.7** | 1,330.7 | – |
| Goodwill and intangible asset impairment, pretax | **16.6** | 122.7 | – |
| TMDP arbitration (recovery) reserve, pretax | **(5.6)** | 32.0 | – |
| Loss on joint venture termination, pretax | **–** | 153.9 | – |
| Deferred recovery clause | **20.2** | (27.3) | 72.2 |
| Refunded to customers | **–** | – | (6.4) |
| Receivables, less allowance for uncollectibles | **32.1** | 96.4 | (64.1) |
| Inventories | **41.9** | 7.0 | (39.4) |
| Prepayments and other deposits | **(0.8)** | (16.5) | 6.3 |
| Taxes accrued | **(82.0)** | 34.5 | 24.1 |
| Interest accrued | **76.7** | (60.7) | 14.2 |
| Accounts payable | **(69.2)** | (17.5) | 98.3 |
| Other | **47.7** | 82.1 | 39.0 |
| Cash flows from operating activities | **139.6** | 311.3 | 655.7 |
| **Cash flows from investing activities** | | | |
| Capital expenditures | **(273.2)** | (590.6) | (1,065.2) |
| Allowance for funds used during construction | **1.0** | 27.4 | 34.5 |
| Purchase of minority interest | **–** | – | (9.9) |
| Net proceeds from sales of business/assets | **349.5** | 296.5 | 103.3 |
| Net cash reduction from deconsolidation | **(22.7)** | – | – |
| Restricted cash | **(34.3)** | (46.2) | – |
| Distributions from (investments in) unconsolidated affiliates | **45.4** | (30.6) | (7.6) |
| Other non-current investments | **24.7** | (32.4) | (715.6) |
| Cash flows from investing activities | **90.4** | (375.9) | (1,660.5) |
| **Cash flows from financing activities** | | | |
| Dividends | **(145.2)** | (165.2) | (215.8) |
| Common stock | **10.2** | 136.6 | 572.6 |
| Proceeds from long-term debt | **–** | 655.1 | 1,758.4 |
| Repayment of long-term debt | **(225.0)** | (526.5) | (949.7) |
| Minority interest | **76.1** | 44.4 | – |
| Restricted cash | **–** | (5.9) | – |
| Early exchange of equity units | **(17.7)** | – | – |
| Settlement of joint venture termination obligation | **–** | (33.5) | – |
| Net increase (decrease) in short-term debt | **77.5** | (323.0) | (278.4) |
| Issuance of preferred securities | **–** | – | 435.6 |
| Equity contract adjustment payments | **(17.4)** | (20.3) | (15.3) |
| Cash flows from financing activities | **(241.5)** | (238.3) | 1,307.4 |
| Net (decrease) increase in cash and cash equivalents | **(11.5)** | (302.9) | 302.6 |
| Cash and cash equivalents at beginning of year | **108.2** | 411.1 | 108.5 |
| Cash and cash equivalents at end of year | **$ 96.7** | $ 108.2 | $ 411.1 |

| | | | |
|---|---|---|---|
| **Supplemental disclosure of cash flow information** | | | |
| Cash paid during the year for: | | | |
| Interest (net of amounts capitalized) (1) | **$ 372.1** | $ 493.1 | $ 160.2 |
| Income taxes | **$ 22.4** | $ 58.8 | $ 71.9 |

(1) Included in interest paid during the year is interest paid on debt obligations for discontinued operations of $51.5 million and $166.6 million for 2004 and 2003, respectively. There was no interest paid on debt obligations for discontinued operations in 2002.

The accompanying notes are an integral part of the consolidated financial statements.

## *Consolidated Statements of Capital*

| (millions) | Shares [1] | Common Stock | Additional Paid-in Capital | Retained Earnings (Deficit) | Accumulated Other Comprehensive Income (Loss) | Unearned Compensation | Total Capital |
|---|---|---|---|---|---|---|---|
| Balance, Dec. 31, 2001 | 139.6 | $139.6 | $ 600.7 | $ 1,298.0 | $ (22.4) | $ (44.3) | $ 1,971.6 |
| Net income for 2002 | | | | 330.1 | | | 330.1 |
| Other comprehensive (loss), after tax | | | | | (18.8) | | (18.8) |
| Common stock issued | 36.2 | 36.2 | 544.4 | | | (8.0) | 572.6 |
| Cash dividends declared | | | | (215.8) | | | (215.8) |
| Amortization of unearned compensation | | | | | | 13.9 | 13.9 |
| Convertible preferred stock – present value of contract adjustment payments | | | (53.1) | | | | (53.1) |
| Tax benefits - ESOP dividends and stock options | | | 2.5 | 1.4 | | | 3.9 |
| Performance shares | | | | | | 7.3 | 7.3 |
| Balance, Dec. 31, 2002 | 175.8 | $175.8 | $ 1,094.5 | $ 1,413.7 | $ (41.2) | $ (31.1) | $ 2,611.7 |
| Net (loss) for 2003 | | | | (909.4) | | | (909.4) |
| Other comprehensive (loss), after tax | | | | | (14.6) | | (14.6) |
| Common stock issued | 12.0 | 12.0 | 125.0 | | | (0.4) | 136.6 |
| Cash dividends declared | | | | (165.2) | | | (165.2) |
| Amortization of unearned compensation | | | | | | 18.3 | 18.3 |
| Tax benefits - ESOP dividends and stock options | | | 1.3 | 0.4 | | | 1.7 |
| Performance shares | | | | | | (1.4) | (1.4) |
| Balance, Dec. 31, 2003 | 187.8 | $187.8 | $ 1,220.8 | $ 339.5 | $ (55.8) | $ (14.6) | $ 1,677.7 |
| Net (loss) for 2004 | | | | (552.0) | | | (552.0) |
| Other comprehensive income, after tax | | | | | 12.0 | | 12.0 |
| Common stock issued | 0.9 | 0.9 | 7.8 | | | 1.5 | 10.2 |
| Cash dividends declared | | | | (145.2) | | | (145.2) |
| Early exchange of equity security units | 10.2 | 10.2 | 251.6 | | | | 261.8 |
| Settlement of claim | 0.8 | 0.8 | 9.2 | | | | 10.0 |
| Amortization of unearned compensation | | | | | | 13.6 | 13.6 |
| Tax benefits - ESOP dividends | | | | 0.1 | | | 0.1 |
| Performance shares | | | | | | (4.3) | (4.3) |
| **Balance, Dec. 31, 2004** | **199.7** | **$199.7** | **$1,489.4** | **$ (357.6)** | **$ (43.8)** | **$ (3.8)** | **$1,283.9** |

(1) TECO Energy had a maximum of 400 million shares of $1 par value common stock authorized as of Dec. 31, 2004, 2003 and 2002.

The accompanying notes are an integral part of the consolidated financial statements.

# 1. Significant Accounting Policies

The significant accounting policies for both utility and diversified operations are as follows:

**Principles of Consolidation**

The consolidated financial statements include the accounts of TECO Energy, Inc. and its majority-owned subsidiaries (TECO Energy or the company). All significant inter-company balances and inter-company transactions have been eliminated in consolidation. Generally, the equity method of accounting is used to account for investments in partnerships or other arrangements in which TECO Energy or its subsidiary companies do not have majority ownership or exercise control.

TECO Energy adopted the provisions of Financial Accounting Standards Board (FASB) Interpretation No. 46 (FIN 46), *Consolidation of Variable Interest Entities, an Interpretation of ARB No. 51,* as of Oct. 1, 2003 with no material impact. Effective Jan. 1, 2004 the company adopted Financial Accounting Standards Board Interpretation No. 46R, *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51,* (FIN 46R) which impacted the consolidation principles applied to certain entities. For entities that are determined to meet the definition of a variable interest entity (VIE), the company obtains information, where possible, to determine if it is the primary beneficiary of the VIE. If the company is determined to be the primary beneficiary, then the VIE is consolidated and a minority interest is recognized for any other third-party interests. If the company is not the primary beneficiary, then the VIE is accounted for using the equity or cost method of accounting. In circumstances this can result in the company consolidating entities in which it has less than a 50% equity investment and deconsolidating entities in which it has a majority equity interest. FIN 46R impacted the consolidation policy for the subsidiaries that hold interests in San José and Alborada power stations in Guatemala, the funding companies involved in the issuance of the trust preferred securities, TECO AGC, Ltd., and Hernando Oaks, LLC (see **Note 2**). For all other entities, the general consolidation principles described above apply.

Results of operations for the proportional share of expenses, revenues and assets reflecting TECO Coalbed Methane's undivided interest in joint venture property are included in the consolidated financial statements through Dec. 31, 2002 (see **Note 16**).

The use of estimates is inherent in the preparation of financial statements in accordance with generally accepted accounting principles (GAAP). Actual results could differ from these estimates.

**Revised Segment Reporting**

In 2003, the company, as part of its renewed focus on core utility and profitable unregulated operations, revised internal reporting information used for decision making purposes. With this change, management focused on the results and performance of TECO Wholesale Generation, Inc. (formerly TECO Power Services Corporation), or TWG-Merchant, as a segment comprised of all merchant operations, from which the Frontera, Union, and Gila River projects' operations have been reclassified to discontinued operations. TWG-Mechant includes the results of operations for the Commonwealth Chesapeake, Dell and McAdams power plants, as well as the equity investment in the Texas Independent Energy (TIE) projects up to the date of sale (see **Note 16** for details), held through PLC Development Holdings, LLC (PLC), and TECO EnergySource (TES), the energy marketing operation for the merchant plants.

The non-merchant operations, formerly included in the TECO Power Services operating segment, are comprised of the results from Hardee Power Partners, Ltd.. (HPP) and the equity investment in the Hamakua power plant in Hawaii, up to the date of sale (see **Note 16** for details), the Guatemalan operations which include equity investments in the San José and Alborada power plants and an equity investment in the Guatemalan distribution company, EEGSA, and other non-merchant activities. These non-merchant power operations are reported in the Other Unregulated segment (see **Note 14**).

**Cash Equivalents**

Cash equivalents are highly liquid, high-quality investments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

**Restricted Cash**

Restricted cash at Dec. 31, 2004 and Dec. 31, 2003 includes \$50.0 million and \$15.4 million, respectively, of cash held in escrow related to the 2003 sale of TECO Coal Corporation's (TECO Coal) indirectly owned synthetic fuel production facilities (to provide credit support for the company's current credit rating). The \$50.0 million of cash from the synthetic fuel facility sale will be retained in escrow to support the company's obligation under the sale agreement, until the expiration of the agreement or TECO Energy achieves an investment-grade credit rating. Restricted cash at Dec. 31, 2004 and Dec. 31, 2003 also includes \$7.1 million and \$36.0 million, respectively, of cash held in escrow related to the 2003 sale of Hardee Power Partners (see **Note 16**).

**Cost Capitalization**

*Development costs* – TECO Energy capitalizes the external costs of construction-related development activities after achieving certain project-related milestones that indicate that completion of a project is probable. Such costs include direct incremental amounts incurred for professional services (primarily legal, engineering and consulting services), permits, options and deposits on land and equipment purchase commitments, capitalized interest and other related costs. In accordance with Statement of Position (SOP) 98-5, *Reporting on the Costs of Start-up Activities,* start-up costs and organization costs are expensed as incurred.

*Debt issuance costs* – The company capitalizes the external costs of obtaining debt financing and amortizes such costs over the life of the related debt.

*Capitalized interest expense* – Interest costs for the construction of non-utility facilities are capitalized and depreciated over the service lives of the related property. TECO Energy capitalized \$0.7 million, \$17.3 million and \$63.2 million of interest costs in 2004, 2003, and 2002, respectively.

**Planned Major Maintenance**

TECO Energy accounts for planned maintenance projects by expensing the costs as incurred. Planned major maintenance projects that do not increase the overall life or value of the related assets are expensed. When the major maintenance materially increases the life or value of the underlying asset, the cost is capitalized. While normal maintenance outages covering various components of the plants generally occur on at least a yearly basis, major overhauls occur less frequently.

Tampa Electric, Peoples Gas System (PGS) and TWG-Merchant expense major maintenance costs as incurred. For Tampa Electric and PGS, concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with Florida Public Service Commission (FPSC) and Federal Energy Regulatory Commission (FERC) regulations.

The San José and Alborada plants in Guatemala each have a long-term power purchase agreement (PPA) with Empresa Eléctrica de Guatemala, S.A. (EEGSA). A major maintenance revenue recovery component is implicit in the capacity payment portion of the PPA for each plant. Accordingly, a portion of each monthly fixed capacity payment is deferred to recognize the portion that reflects recovery of future planned major maintenance expenses. Actual maintenance costs are expensed when incurred with a like amount of deferred recovery revenue recognized at the same time.

### Depreciation

TECO Energy provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage value, of depreciable property over its estimated service life. Unregulated electric generating, pipeline and transmission facilities are depreciated over the expected useful lives of the related equipment, a period of up to 40 years. The provision for total regulated and unregulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 3.9% for 2004, 4.5% for 2003 and 4.2% for 2002. For the year ended Dec. 31, 2003, Tampa Electric recognized depreciation expense of $36.6 million related to accelerated depreciation of certain Gannon power station coal-fired assets, in accordance with a regulatory order issued by the FPSC. Construction work-in-progress is not depreciated until the asset is completed or placed in service.

The implementation of FAS 143, *Accounting for Asset Retirement Obligations*, in 2003 resulted in an increase in the carrying amount of long-lived assets and the reclassification of the accumulated reserve for cost of removal as "Regulatory liabilities" for all periods presented. The adjusted capitalized amount is depreciated over the remaining useful life of the asset. See **Note 15.**

### Allowance for Funds Used During Construction (AFUDC)

AFUDC is a non-cash credit to income with a corresponding charge to utility plant which represents the cost of borrowed funds and a reasonable return on other funds used for construction. The rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 7.79% for 2004, 2003 and 2002. Total AFUDC for 2004, 2003 and 2002 was $1.0 million, $27.4 million and $34.5 million, respectively. The base on which AFUDC is calculated excludes construction work-in-progress which has been included in rate base.

### Investments in Unconsolidated Affiliates

Investments in unconsolidated affiliates are accounted for using the equity method of accounting. The percentage ownership interest for each investment at Dec. 31, 2004 and 2003 is presented in the following table:

**TECO Energy and Subsidiaries' Percent Ownership in Unconsolidated Affiliates**

| *Dec. 31,* | *2004* | *2003* |
|---|---|---|
| **TECO Wholesale Generation (TWG)** | | |
| Texas Independent Energy, L.P. (TIE) [1] | – | 50% |
| **TECO Transport** | | |
| Ocean Dry Bulk, LLC | 50% | – |
| **Other unregulated** | | |
| Empresa Eléctrica de Guatemala, S.A. (EEGSA) | 24% | 24% |
| Central Generadora Eléctrica San San José, Limitada (San José)[2] | 100 | – |
| Tampa Centro Americana de Electricidad, Limitada (Alborada)[2] | 96 | – |
| Hamakua Energy Partners, L.P.[3] | – | 50 |
| Hamakua Land Partnership, LLP[3] | – | 50 |
| US Propane, LLC [4] | – | 38 |
| TECO AGC, Ltd.. [5][7] | – | 50 |
| Litestream Technologies, LLC [6] | 36 | 36 |
| Hernando Oaks, LLC [7] | – | 50 |
| Brandon Properties Partners, Ltd.. [8] | – | 50 |
| Walden Woods Business Center, Ltd.. | 50 | 50 |
| TECO Capital Funding LLC I[9] | 100 | – |
| TECO Capital Funding LLC II[9] | 100 | – |

(1) In August 2004, a TWG-Mechant subsidiary completed the sale of its 50-percent indirect interest in TIE (the holding company for the Odessa and Guadalupe project entities). See **Note 16** for additional information about this sale.
(2) As of Jan. 1, 2004, in accordance with the interpretation and application of the consolidation guidance established in FIN 46R to long-term power purchase agreements, TECO Energy can no longer consolidate CGE or TCAE, the project companies for the San José and Alborada power plants, respectively, in Guatemala. The percent ownership is unchanged from Dec. 31, 2003. See **Note 2** for additional details.
(3) See **Note 16** for information about the sale in July 2004 of TECO Energy's indirect interest in Hamakua.
(4) The sale of U.S. Propane, LLC assets was completed in the second quarter of 2004 (see **Note 16**).
(5) The sale of TECO AGC, Ltd. assets was completed in November 2004.
(6) During the second quarter of 2004, the assets of Litestream Technologies, LLC were sold in bankruptcy. The company still indirectly owned a 36% interest in Litestream Technologies, LLC as of Dec. 31, 2004.
(7) As of Jan. 1, 2004, in accordance with FIN 46R, the company determined that it is the primary beneficiary of this entity. As a result, this entity is included in the consolidated financial statements of the company as a fully consolidated entity with a significant minority interest. The percent ownership is unchanged from Dec. 31, 2003. See **Note 2** for additional details.
(8) Brandon Properties was dissolved in 2004.
(9) As of Jan. 1, 2004, in accordance with the interpretation and application of the consolidation guidance established in FIN 46R, TECO Energy can no longer consolidate Capital Funding I & II. See **Note 7** and **Note 2** for additional details. The percent ownership is unchanged from Dec. 31, 2003.

### Regulatory Assets and Liabilities

Tampa Electric and PGS are subject to the provisions of FASB statement No. 71, *Accounting for the Effects of Certain Types of regulation* (see **Note 3** for additional details).

### Deferred Income Taxes

TECO Energy utilizes the liability method in the measurement of deferred income taxes. Under the liability method, the temporary differences between the financial statement and tax bases of assets and liabilities are reported as deferred taxes measured at current tax rates. Tampa Electric and PGS are regulated, and their books and records reflect approved regulatory treatment, including certain adjustments to accumulated deferred income taxes and the establishment of a corresponding regulatory tax liability reflecting the amount payable to customers through future rates.

### Investment Tax Credits

Investment tax credits have been recorded as deferred credits and are being amortized as reductions to income tax expense over the service lives of the related property.

**Revenue Recognition**

TECO Energy recognizes revenues consistent with the Securities and Exchange Commission's Staff Accounting Bulletin (SAB) 104, *Revenue Recognition in Financial Statements.* The interpretive criteria outlined in SAB 104 are that 1) there is persuasive evidence that an arrangement exists; 2) delivery has occurred or services have been rendered; 3) the fee is fixed and determinable; and 4) collectibility is reasonably assured. Except as discussed below, TECO Energy and its subsidiaries recognize revenues on a gross basis when earned for the physical delivery of products or services and the risks and rewards of ownership have transferred to the buyer. Revenues for any financial or hedge transactions that do not result in physical delivery are reported on a net basis.

The regulated utilities' (Tampa Electric and PGS) retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by FERC. See **Note 3** for a discussion of significant regulatory matters and the applicability of Financial Accounting Standard No. (FAS) 71, *Accounting for the Effects of Certain Types of Regulation,* to the company.

Revenues for certain transportation services at TECO Transport are recognized using the percentage of completion method, which includes estimates of the distance traveled and/or the time elapsed, compared to the total estimated contract.

**Revenues and Fuel Costs**

Revenues include amounts resulting from cost recovery clauses which provide for monthly billing charges to reflect increases or decreases in fuel, purchased power, conservation and environmental costs for Tampa Electric and purchased gas, interstate pipeline capacity and conservation costs for PGS. These adjustment factors are based on costs incurred and projected for a specific recovery period. Any over-recovery or under-recovery of costs plus an interest factor are taken into account in the process of setting adjustment factors for subsequent recovery periods. Over-recoveries of costs are recorded as deferred credits, and under-recoveries of costs are recorded as deferred charges.

Certain other costs incurred by the regulated utilities are allowed to be recovered from customers through prices approved in the regulatory process. These costs are recognized as the associated revenues are billed. The regulated utilities accrue base revenues for services rendered but unbilled to provide a closer matching of revenues and expenses. See **Note 3**.

As of Dec. 31, 2004 and 2003, unbilled revenues of $46.3 million and $45.7 million, respectively, are included in the "Receivables" line item on the balance sheet.

**Purchased Power**

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. As a result of the sale of HPP in October 2003 (see **Note 16**), power purchases from HPP, subsequent to the sale, are reflected as non-affiliate purchases by Tampa Electric. Tampa Electric's long-term power purchase agreement from HPP was not affected by the sale of HPP. Under the existing purchase power agreement, which has been approved by the Federal Energy Regulatory Commission (FERC) and the Florida Public Service Commission (FPSC), Tampa Electric has full entitlement to the output of the CT2B unit at all times and full entitlement to the output of the remaining units at the Hardee power station at all times except when Seminole Electric Cooperative has entitlement due to outages and/or derations on a specified portion of its generating units. Tampa Electric purchased power from non-TECO Energy affiliates, including purchases from HPP, at a cost of $172.3 million, $234.9 million and $253.7 million, respectively, for the years ended Dec. 31, 2004, 2003 and 2002. The associated revenue at HPP from power sold to Tampa Electric of $50.1 million and $51.4 million for 2003 and 2002, respectively, is offset against "Regulated operations - Purchased power" in the income statement. The purchased power costs at Tampa Electric are recoverable through an FPSC-approved cost recovery clause.

**Accounting for Excise Taxes, Franchise Fees and Gross Receipts**

TECO Coal and TECO Transport incur most of TECO Energy's total excise taxes, which are accrued as an expense and reconciled to the actual cash payment of excise taxes. As general expenses, they are not specifically recovered through revenues. Excise taxes paid by the regulated utilities are not material and are expensed when incurred.

The regulated utilities are allowed to recover certain costs incurred from customers through prices approved by the FPSC. The amounts included in customers' bills for franchise fees and gross receipt taxes are included as revenues on the Consolidated Statements of Income. These amounts totaled $83.8 million, $77.7 million and $73.8 million for the years ended Dec. 31, 2004, 2003 and 2002, respectively. Franchise fees and gross receipt taxes payable by the regulated utilities are included as an expense on the Consolidated Statements of Income in "Taxes, other than income." For the years ended Dec. 31, 2004, 2003 and 2002, these totaled $83.6 million, $77.5 million and $73.7 million, respectively.

**Asset Impairments**

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* which superseded FAS 121, *Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of.* FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a component of a business.

In accordance with FAS 144, the company assesses whether there has been an impairment of its long-lived assets and certain intangibles held and used by the company when such impairment indicators exist. Indicators of impairment existed for certain asset groups, triggering a requirement to ascertain the recoverability of these assets using undiscounted cash flows before interest expense. See **Note 18** for specific details regarding the results of these assessments.

**Deferred Credits and Other Liabilities**

Other deferred credits primarily include the accrued post-retirement benefit liability, the pension liability, incurred but not reported medical and general liability claims, and deferred gains on sale-lease back transactions involving marine assets.

**Stock-Based Compensation**

TECO Energy has adopted the disclosure-only provisions of FAS 123, *Accounting for Stock-Based Compensation,* but applies Accounting Principles Board Opinion No. (APB) 25, *Accounting for Stock Issued to Employees,* and related interpretations in accounting for its stock-based compensation plans. Effective Jan. 1, 2003, the company adopted FAS 148, *Accounting for Stock-Based Compensation–Transition and Disclosure, an amendment of FASB Statement No. 123.* This standard amends FAS 123 to provide alternative methods of transition for companies that voluntarily change to the fair value-based method of accounting for stock-based employee compensation. It also requires prominent disclosure about the effects on reported net income of the company's accounting policy decisions with respect to stock-based employee compensation in both annual and interim financial statements.

Stock options are granted with an option price greater than or equal to the fair value on the grant date, therefore no compensation expense has been recognized for stock options granted under the Equity Plans and Director Equity Plans (see **Note 9** for a description of the plans). If the company had elected to recognize compensation expense for stock options based on the fair value at grant date, consistent with the method prescribed by FAS 123, net income and earnings per share would have been reduced to the pro forma amounts as follows. These pro forma amounts were determined using the Black-Scholes valuation model with weighted average assumptions set forth below:

**Pro Forma Stock-Based Compensation Expense**

| *(millions, except per share amounts)* *For the years ended Dec. 31,* | | *2004* | *2003* | *2002* |
|---|---|---|---|---|
| Net (loss) income from continuing operations | As reported | $(404.4) | $ 61.7 | $ 268.5 |
| | *Add:* Unearned compensation expense [1] | 3.2 | 1.0 | 1.0 |
| | *Less:* Pro forma expense [2] | 7.1 | 3.7 | 6.1 |
| | Pro forma | $(408.3) | $ 59.0 | $ 263.4 |
| Net (loss) income | As reported | $(552.0) | $ (909.4) | $ 330.1 |
| | *Add:* Unearned compensation expense [1] | 3.2 | 1.0 | 1.0 |
| | *Less:* Pro forma expense [2] | 7.1 | 3.7 | 6.1 |
| | Pro forma | $(555.9) | $ (912.1) | $ 325.0 |
| Net (loss) income from continuing operations - EPS, basic | As reported | $ (2.10) | $ 0.34 | $ 1.75 |
| | Pro forma | $ (2.12) | $ 0.33 | $ 1.72 |
| Net (loss) income from continuing operations - EPS, diluted | As reported | $ (2.10) | $ 0.34 | $ 1.75 |
| | Pro forma | $ (2.12) | $ 0.33 | $ 1.72 |
| Net (loss) income - EPS, basic | As reported | $ (2.87) | $ (5.05) | $ 2.15 |
| | Pro forma | $ (2.89) | $ (5.07) | $ 2.12 |
| Net (loss) income - EPS, diluted | As reported | $ (2.87) | $ (5.04) | $ 2.15 |
| | Pro forma | $ (2.89) | $ (5.06) | $ 2.12 |
| Assumptions | | | | |
| Risk-free interest rate | | 4.04% | 3.52% | 5.09% |
| Expected lives (in years) | | 7 | 7 | 6 |
| Expected stock volatility | | 34.09% | 32.68% | 25.92% |
| Dividend yield | | 5.67% | 6.87% | 5.47% |

(1) Unearned compensation expense reflects the compensation expense of restricted stock awards, after-tax.
(2) Compensation expense for stock options determined using the fair-value based method, after tax, plus compensation expense associated with restricted stock awards, after tax.

**Restrictions on Dividend Payments and Transfer of Assets**

Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The primary sources of funds to pay dividends on TECO Energy's common stock are dividends and other distributions from its operating companies. TECO Energy's $380 million note indenture contains a covenant that requires the company to achieve certain interest coverage levels in order to pay dividends. TECO Energy's credit facility contains a covenant that could limit the payment of dividends exceeding $50 million in any quarter under certain circumstances. In March 2004 Tampa Electric repaid $75 million of 7.75% first mortgage bonds issued under an indenture that included a limitation on dividends covenant. This covenant is no longer operative since there are no bonds outstanding under the indenture. Certain long-term debt at PGS contains restrictions that limit the payment of dividends and distributions on the common stock of Tampa Electric. Tampa Electric's $125 million credit facility, which included a covenant limiting cumulative distributions and outstanding affiliate loans, was amended in 2004 resulting in the elimination of this covenant.

In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport, TECO Coal and TECO Solutions, has a guarantee related to a coal supply agreement that limits the payment of dividends to its common shareholder, TECO Energy, but does not limit loans or advances.

See **Notes 6, 7 and 12** for a more detailed description of significant financial covenants.

TECO Energy holds the right to defer payments on its subordinated notes issued in connection with the issuance of trust preferred securities by TECO Capital Trust I and TECO Capital Trust II. Should the company exercise this right, it would be prohibited from paying cash dividends on its common stock until the unpaid distributions on the subordinated notes are made. TECO Energy has not exercised that right.

**Foreign Operations**

The functional currency of the company's foreign investments is primarily the U.S. dollar. Transactions in the local currency are re-measured to the U.S. dollar for financial reporting purposes. The aggregate re-measurement gains or losses included in net income in 2004, 2003, and 2002 were not significant. The foreign investments are generally protected from any significant currency gains or losses by the terms of the power sales agreements and other related contracts, in which payments are defined in U.S. dollars.

**Reclassifications**

Certain prior year amounts were reclassified to conform to the current year presentation. Results for all prior periods have been reclassified from continuing operations to discontinued operations as appropriate for each of the entities as discussed in **Note 21.**

## *2. New Accounting Pronouncements*

**Gains and Losses on Energy Trading Contracts**

On Oct. 25, 2002, the Emerging Issues Task Force released EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17,* which 1) precludes mark-to-market accounting for energy trading contracts that are not derivatives pursuant to FAS 133, 2) requires that gains and losses on all derivative instruments within the scope of FAS 133 be presented on a net basis in the income statement if held for trading purposes, and 3) limits the circumstances in which a reporting entity may recognize a "day one" gain or loss on a derivative contract. The measurement provisions of the issue are effective for all fiscal periods beginning after Dec. 15, 2002. The net presentation provisions are effective for all financial statements issued after Dec. 15, 2002. The adoption of the measurement provisions on Jan. 1, 2003 did not have a material impact. See **Note 21** for additional details of amounts presented on a net basis.

**Consolidation of Variable Interest Entities**

The equity method of accounting is generally used to account for significant investments in arrangements in which we or our subsidiary companies do not have a majority ownership interest or exercise control. A new approach for determining if a reporting entity should consolidate certain legal entities, including partnerships, limited liability companies, or trusts, among others, collectively defined as VIEs was developed and later revised under FIN 46 (FIN 46R), *Consolidation of Variable Interest Entities, an interpretation of ARB No. 51.*

A legal entity is considered a VIE, with some exemptions if specific criteria are met, if it does not have sufficient equity at risk to finance its own activities without relying on financial support from other parties. Additional criteria must be applied to determine if this condition is met or if the equity holders, as a group, lack any one of three stipulated characteristics of a controlling financial interest. If the legal entity is a VIE, then the reporting entity determined to be the primary beneficiary of the VIE must consolidate it. Even if a reporting entity is not obligated to consolidate a VIE, then certain disclosures must be made about the VIE if the reporting entity has a significant variable interest.

TECO Energy adopted the provisions of FIN 46 as of Oct. 1, 2003 with no material impact. As of Jan. 1, 2004, FIN 46R was adopted for the remaining VIEs as described below.

The company formed TCAE to own and construct the Alborada Power Station in Guatemala in 1995 . The company formed CGE to own and commence construction of the San José Power Station in Guatemala in 1998. The San José Power Station was completed in 2000. Both projects obtained a long-term power purchase agreement (PPA) with EEGSA, a distribution utility in Guatemala. The terms of the two separate PPAs include EEGSA's right to the full capacity of the plants for 15 years, U.S. dollar based capacity payments, certain terms for providing fuel and certain other terms including the right to extend the Alborada and San José contracts. Management believes that EEGSA is the primary beneficiary of the variable interests in TCAE and CGE due to the terms of the PPA. Accordingly, both entities were deconsolidated as of Jan. 1, 2004. The TCAE deconsolidation resulted in the initial removal of $25 million of debt and $15.1 million of net assets from the balance sheet. The San José deconsolidation resulted in the initial removal of $65.5 million of debt and $106.6 million of net assets from the balance sheet. The results of operations for the two projects are classified as "Income from Equity Investments" in the Consolidated Statements of Income since the date of deconsolidation.

TECO Funding I, LLC and TECO Funding II, LLC are limited liability, wholly-owned subsidiaries of TECO Energy. These funding companies sold preferred securities to Capital Trust I and Capital Trust II (see **Note 7** for additional details of the activities of the trusts). The funding companies used those proceeds to purchase junior subordinated notes from TECO Energy. The funding companies are considered VIEs in accordance with FIN 46R. Since management does not believe the company has any material exposure to losses as a result of its involvement with TECO Funding I and II, these entities were deconsolidated as of Jan. 1, 2004 reflecting that the company is not the primary beneficiary of the funding companies. The Funding companies are presented as equity investments in the balance sheet. The impact of the deconsolidation was an increase in liabilities of $20.2 million and a corresponding increase in assets.

Pike Letcher Synfuel, LLC was established as part of the Apr. 1, 2003, sale of TECO Coal's synthetic fuel production facilities. TECO Energy's maximum loss exposure in this entity is its equity investment of approximately $10.9 million and losses related to the production costs for the future production of synthetic fuel, in the event that such production creates Section 29 non-conventional fuel tax credits in excess of TECO Energy's or the other buyers' capacity to generate sufficient taxable income to use such credits. Management believes that the company is the primary beneficiary of this VIE and continues to consolidate the entity under the guidance of FIN 46R.

TECO Transport entered into two separate sale leaseback transactions for certain vessels which were recognized as sales in December 2001 and December 2002, and are currently recognized as operating leases for use of the assets. The sale leaseback transactions were entered into with separate third parties that the company believes meet the definition of a VIE. TECO Transport currently leases two ocean going tugboats, four ocean going barges, five river towboats and 49 river barges through these two trusts. The estimated maximum loss exposure faced by TECO Transport is the incremental cost of obtaining suitable equipment to meet the company's contractual shipping obligations. In accordance with the guidance of FIN 46R, management has concluded that the company is not the primary beneficiary of the lessor trusts and continues to report only the impacts of the operating leases and any other required cash contributions.

TECO Properties formed a limited liability company with a project developer which meets the definition of a VIE. Hernando Oaks, LLC was formed by TECO Properties with the Pensacola Group to buy and develop 627 acres of land in Hernando County, Florida into a residential golf community comprised of an 18 hole golf course and 975 single family lots for sale to homebuilders. The company has provided subordinated financial support in the form of a guarantee on behalf of the limited liability company and determined that it is the primary beneficiary of Hernando Oaks. The company consolidated Hernando Oaks, LLC as of Jan. 1, 2004, resulting in an increase in assets of $18.5 million and a corresponding increase in liabilities.

A subsidiary of TECO Solutions formed a partnership to construct, own and operate a water cooling plant to produce and distribute chilled water to customers via a local distribution loop primarily for use in air conditioning systems. The partnership, TECO AGC, Ltd.., meets the definition of a VIE. The company is the primary beneficiary, in accordance with FIN 46R, due to subordinated financing of $3.3 million provided to the partnership as of Dec. 31, 2003, in addition to the company's equity investment. This note receivable from the partnership is collateralized by the assets in the partnership. The company consolidated TECO AGC, Ltd.. as of Jan. 1, 2004 with no material increase in assets or liabilities.

In 1992, a subsidiary of the company, Hardee Power Partners, Ltd.. (HPP) commenced construction of the Hardee Power Station in central Florida. HPP obtained dual 20-year PPAs with Tampa Electric and another Florida utility company to provide peaking capacity. The company sold its interest in HPP to an affiliate of Invenergy LLC and GTCR Golden Rauner LLC in 2003. Under FIN 46R, the company is required to make an exhaustive effort to obtain sufficient information to determine if HPP is a VIE and which holder of the variable interests is the primary beneficiary. The new owners of HPP are not willing to provide the information necessary to make these determinations and have no obligation to do so. The information is not available publicly. As a result, the company is unable to determine if HPP is a VIE and if so, which variable interest holder, if any, is the primary beneficiary. The maximum exposure for the company is the ability to purchase electricity under terms of the PPA with HPP at rates unfavorable to the wholesale market. For a description and measure of the purchases of electricity under the HPP PPA, see **Note 1 – Purchased Power.**

**Amendment to Derivatives Accounting**

In April 2003, the FASB issued FAS 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities,* which clarifies the definition of a derivative and modifies, as necessary, FAS 133 to reflect certain decisions made by the FASB as part of the Derivatives Implementation Group (DIG) process. The majority of the guidance was already effective and previously applied by the company in the course of the adoption of FAS 133.

In particular, FAS 149 incorporates the conclusions previously reached in 2001 under DIG Issue C10, *Can Option Contracts and Forward Contracts with Optionality Features Qualify for the Normal Purchases and Normal Sales Exception?,* and DIG Issue C15, *Normal Purchases and Normal Sales Exception for Certain Option-Type Contracts and Forward Contracts in Electricity.* In limited circumstances when the criteria are met and documented, TECO Energy designates option-type and forward contracts in electricity as a normal purchase or normal sale (NPNS) exception to FAS 133. A contract designated and documented as qualifying for the NPNS exception is not subject to the measurement and recognition requirements of FAS 133. The incorporation of the conclusions reached under DIG Issues C10 and C15 into the standard did not and will not have a material impact on the consolidated financial statements of TECO Energy.

FAS 149 establishes multiple effective dates based on the source of the guidance. For all DIG Issues previously cleared by the FASB and not modified under FAS 149, the effective date of the issue remains the same. For all other aspects of the standard, the guidance is effective for all contracts entered into or modified after Jun. 30, 2003. The adoption of the additional guidance in FAS 149 did not have a material impact on the consolidated financial statements.

**Financial Instruments with Characteristics of both Liabilities and Equity**

In May 2003, the FASB issued FAS 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity*, which requires that an issuer classify certain financial instruments as a liability or an asset. Previously, many financial instruments with characteristics of both liabilities and equity were classified as equity. Financial instruments subject to FAS 150 include financial instruments with any of the following features:

- An unconditional redemption obligation at a specified or determinable date, or upon an event that is certain to occur;
- An obligation to repurchase shares, or indexed to such an obligation, and may require physical share or net cash settlement;
- An unconditional, or for new issuances conditional, obligation that may be settled by issuing a variable number of equity shares if either (a) a fixed monetary amount is known at inception, (b) the variability is indexed to something other than the fair value of the issuer's equity shares, or (c) the variability moves inversely to changes in the fair value of the issuer's shares.

The standard requires that all such instruments be classified as a liability, or an asset in certain circumstances, and initially measured at fair value. Forward contracts that require a fixed physical share settlement and mandatorily redeemable financial instruments must be subsequently re-measured at fair value on each reporting date.

This standard is effective for all financial instruments entered into or modified after May 31, 2003, and for all other financial instruments, at the beginning of the first interim period beginning after Jun. 15, 2003. See **Note 7** for a discussion of the impact of the adoption of this standard on Jul. 1, 2003.

**Reporting Discontinued Operations**

Emerging Issues Task Force (EITF) Issue No. 03-13, *Applying the Conditions in Paragraph 42 of FASB Statement No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, in Determining Whether to Report Discontinued Operations.* The company has adopted the guidance provided by the EITF as related to assessing the actual or projected direct and indirect cash flows of a disposal component to assess the extent or lack of continuing involvement. As a result of this assessment, the sale of Frontera and the expected sale of BCH will be reported as "Assets and Liabilities Held for Sale" and the results for both disposal components are reported as "Discontinued Operations".

**Stock-Based Compensation**

FASB Statement No. 123 (revised 2004), *Share-Based Payment*, will become effective for periods after Jun. 15, 2005. The revision to FAS 123 will require financial statement cost recognition for certain share-based payment transactions that are made after the effective date in return for goods and services. Additionally, the revision will require financial statement cost recognition for certain share-based payment transactions that have been made prior to the effective date but for which the requisite service is provided after the effective date. (See **Note 1** to the Consolidated Financial Statements, which includes proforma information to assess the impact of implementing the revised statement.)

**Inventory Costs**

FASB Statement No. 151, *Inventory Costs, an amendment to ARB No. 43, Chapter 4*, sets forth certain costs related to inventory that must be included as current period costs. This Statement becomes effective for periods beginning after Jun. 15, 2005 and is not expected to materially impact the company.

**Nonmonetary Assets**

FASB Statement No. 153, *Exchanges of Nonmonetary Assets, an amendment of APB Opinion No. 29*, becomes effective for periods beginning after Jun. 15, 2005 and is not expected to materially impact the company.

## 3. Regulatory

As discussed in **Note 1**, Tampa Electric's and PGS' retail business are regulated by the FPSC.

**Base Rate – Tampa Electric**

Tampa Electric's rates and allowed return on equity (ROE) range of 10.75% to 12.75% with a midpoint of 11.75% are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions as a result of rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties. Tampa Electric expects to continue maintaining earnings within its allowed ROE range for the foreseeable future.

Tampa Electric has not sought a base rate increase to recover significant plant investment, including the Bayside Power Station, which entered service in 2003 and 2004.

**Cost Recovery – Tampa Electric**

*2004 Proceedings*

In September 2004, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January through December 2005. In November, the FPSC approved Tampa Electric's requested changes. The rates include the impacts of increased natural gas and coal prices, the collection of underestimated 2004 fuel expenses, the proceeds from the sale of SO2 emissions allowances associated with Hookers Point Station and the O&M costs associated with the Environmental Protection Agency (EPA) Consent Decree and Florida Department of Environmental Protection (FDEP) Consent Final Judgment required Big Bend Units 1 - 3 Pre-SCR projects (see **Note 12** for additional details regarding projected environmental expenditures). In addition, the rates also reflect the FPSC's September 2004 decision to reduce the annual cost recovery amount for water transportation services for coal and petroleum coke provided under Tampa Electric's contract with TECO Transport described below (See **Note 13**). The 2004 costs associated with this disallowance were recognized in 2004.

As part of the regulatory process, it is reasonably likely that third parties may intervene on similar matters in the future. The company is unable to predict the timing, nature or impact of such future actions.

**Base Rate – PGS**

As a result of a base rate proceeding, effective Jan. 16, 2003 PGS' allowable ROE range is 10.25% to 12.25% with an 11.25% midpoint. PGS expects to continue earning within its allowed ROE range for the foreseeable future.

### Cost Recovery – PGS

In November 2004, the FPSC approved the annual cap on rates under PGS' Purchased Gas Adjustment (PGA) cap factor for the period January 2005 through December 2005. The PGA is a factor that can vary monthly due to changes in actual fuel costs but is not anticipated to exceed the annual cap.

### Other Items

*Regional Transmission Organization (RTO)*

In October 2002, the RTO process involving the proposed formation of GridFlorida, LLC, as initiated in response to the Federal Energy Regulatory Commission's (FERC's) continuing efforts to affect open access to transmission facilities in large regional markets, was delayed when the Office of Public Counsel (OPC) filed an appeal with the Florida Supreme Court asserting that the FPSC could not relinquish its jurisdictional responsibility to regulate the investor-owned electric utilities (IOUs) and the approval of GridFlorida would result in such a relinquishment. Oral arguments occurred in May 2003, and the Florida Supreme Court dismissed the OPC appeal citing that it was premature because certain portions of the FPSC GridFlorida order were not final.

In September 2003, a joint meeting of the FERC and FPSC took place to discuss wholesale markets and RTO issues related to GridFlorida and, in particular, federal/state interactions. During 2004, deliberations by the FPSC were put on hold to allow a consulting firm, engaged by the GridFlorida applicants, to conduct a cost/benefit study of the GridFlorida RTO. As a result, the FPSC held a series of collaborative meetings during the year with all interested parties to facilitate development of the study methodology as well as participate in the submission of data required to complete the study. Upon conclusion of the study, which is expected to occur in the first quarter of 2005, the study results will be presented to the FPSC. The FPSC is then expected to set the remaining items for hearing and establish a hearing schedule.

*Storm Damage Cost Recovery*

Following Hurricane Andrew in 1992, Florida's IOUs were unable to obtain transmission and distribution insurance coverage in the event of hurricanes, tornados or other damage due to destructive acts of nature. Tampa Electric and other IOUs were permitted to implement a self-insurance program effective Jan. 1, 1994 for such costs of restoration, and the FPSC authorized Tampa Electric to accrue $4 million annually to grow its unfunded storm damage reserve. Tampa Electric had never utilized its reserve before the 2004 hurricane season and would have had a reserve balance of $44 million at Dec. 31, 2004.

The costs for restoration associated with hurricanes Charley, Frances and Jeanne were estimated to be $72 million at year-end, which exceeded the storm damage reserve by $28 million. These excess costs over the reserve amounts were charged against the reserve and are reflected as a regulatory asset at Dec. 31, 2004. The storm costs did not reduce earnings but did reduce cash flow from operations.

Tampa Electric filed for and received approval from the FPSC to defer prudently incurred storm damage restoration costs to the reserve until alternative accounting treatment is sought. At this time Tampa Electric is evaluating several options, based upon other Florida public utilities' proceedings before the FPSC.

*Coal Transportation Contract*

In September 2004, the FPSC voted to disallow certain costs that Tampa Electric can recover from its customers for waterborne fuel transportation services under a contract with TECO Transport (see **Note 13** and **Note 23** for additional details).

### Regulatory Assets and Liabilities

Tampa Electric and PGS maintain their accounts in accordance with recognized policies of the FPSC. In addition, Tampa Electric maintains its accounts in accordance with recognized policies prescribed or permitted by the FERC. These policies conform with GAAP in all material respects.

Tampa Electric and PGS apply the accounting treatment permitted by FAS 71, *Accounting for the Effects of Certain Types of Regulation.* Areas of applicability include deferral of revenues under approved regulatory agreements; revenue recognition resulting from cost recovery clauses that provide for monthly billing charges to reflect increases or decreases in fuel; purchased power, conservation and environmental costs; and deferral of costs as regulatory assets, when cost recovery is ordered over a period longer than a fiscal year, to the period that the regulatory agency recognizes them. Details of the regulatory assets and liabilities as of Dec. 31, 2004 and 2003 are presented in the following table:

**Regulatory Assets and Liabilities**

| *(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| **Regulatory assets:** | | |
| Regulatory tax asset [1] | $ 57.6 | $ 63.3 |
| Other: | | |
| Cost recovery clauses | 48.2 | 59.7 |
| Coal contract buy-out [2] | – | 2.7 |
| Deferred bond refinancing costs [3] | 32.5 | 32.2 |
| Environmental remediation | 16.9 | 20.7 |
| Competitive rate adjustment | 6.1 | 5.3 |
| Transmission and distribution storm reserve | 28.0 | – |
| Other | 11.6 | 4.4 |
| | 143.3 | 125.0 |
| Total regulatory assets | $ 200.9 | $ 188.3 |
| **Regulatory liabilities:** | | |
| Regulatory tax liability [1] | $ 29.5 | $ 29.9 |
| Other: | | |
| Deferred allowance auction credits | 2.3 | 1.9 |
| Recovery clause related | 8.7 | – |
| Environmental remediation | 16.9 | 20.7 |
| Transmission and distribution storm reserve | – | 40.0 |
| Deferred gain on property sales | 1.7 | 1.9 |
| Accumulated reserve – cost of removal | 479.9 | 462.2 |
| Other | – | 3.6 |
| | 509.5 | 530.3 |
| Total regulatory liabilities | $ 539.0 | $ 560.2 |

(1) Related to plant life. Includes $14.6 million and $17.0 million of excess deferred taxes as of Dec. 31, 2004 and Dec. 31, 2003, respectively.
(2) Amortized over a 10-year period ending December 2004.
(3) Amortized over the term of the related debt instrument.

## *4. Income Tax Expense*

Income tax expense consists of the following components:

**Income Tax Expense (Benefit)**

| *(millions)* | *Federal* | *Foreign* | *State* | *Total* |
|---|---|---|---|---|
| **2004** | | | | |
| Continuing operations | | | | |
| Current payable | **$ (9.1)** | **$ (1.1)** | **$ 10.6** | **$ 0.4** |
| Deferred | **(217.6)** | **0.3** | **(45.3)** | **(262.6)** |
| Amortization of investment tax credits | **(2.9)** | **–** | **–** | **(2.9)** |
| Income tax (benefit) from continuing operations | **(229.6)** | **(0.8)** | **(34.7)** | **(265.1)** |
| Discontinued operations | | | | |
| Current payable | **9.7** | **–** | **5.5** | **15.2** |
| Deferred | **(86.1)** | **–** | **(6.6)** | **(92.7)** |
| Income tax (benefit) from discontinued operations | **(76.4)** | **–** | **(1.1)** | **(77.5)** |
| Total income tax (benefit) | **$ (306.0)** | **$ (0.8)** | **$ (35.8)** | **$ (342.6)** |
| **2003** | | | | |
| Continuing operations | | | | |
| Current payable | $ 58.3 | $ 2.2 | $ 7.4 | $ 67.9 |
| Deferred | (143.0) | 5.3 | (17.0) | (154.7) |
| Amortization of investment tax credits | (4.7) | – | – | (4.7) |
| Income tax (benefit) expense from continuing operations | (89.4) | 7.5 | (9.6) | (91.5) |
| Discontinued operations | | | | |
| Current payable | (0.3) | – | 7.1 | 6.8 |
| Deferred | (519.7) | – | (35.0) | (554.7) |
| Income tax (benefit) from discontinued operations | (520.0) | – | (27.9) | (547.9) |
| Total income tax (benefit) expense | $ (609.4) | $ 7.5 | $ (37.5) | $ (639.4) |
| **2002** | | | | |
| Continuing operations | | | | |
| Current payable | $ 11.0 | $ 1.0 | $ 10.3 | $ 22.3 |
| Deferred | (69.2) | – | (5.2) | (74.4) |
| Amortization of investment tax credits | (4.8) | – | – | (4.8) |
| Income tax (benefit) expense from continuing operations | (63.0) | 1.0 | 5.1 | (56.9) |
| Discontinued operations | | | | |
| Current payable | 29.0 | – | 5.8 | 34.8 |
| Deferred | (20.0) | – | (2.2) | (22.2) |
| Income tax expense from discontinued operations | 9.0 | – | 3.6 | 12.6 |
| Total income tax (benefit) expense | $ (54.0) | $ 1.0 | $ 8.7 | $ (44.3) |

TECO Energy uses the liability method to determine deferred income taxes. Under the liability method, the company estimates its current tax exposure and assesses the temporary differences resulting from differences in the treatment of items, such as depreciation, for financial statement and tax purposes. These differences are reported as deferred taxes, measured at current rates, in the consolidated financial statements. Management reviews all reasonably available current and historical information, including forward-looking information, to determine if it is more likely than not, that some or all of the deferred tax asset will not be realized. If management determines that it is likely that some or all of a deferred tax asset will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized.

Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's core utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2004 will be realized in future periods.

The principal components of the company's deferred tax assets and liabilities recognized in the balance sheet are as follows:

**Deferred Income Tax Assets and Liabilities**

| *(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| Deferred income tax assets [(1)] | | |
| Property related | **$ 780.3** | $ 517.3 |
| Alternative minimum tax credit forward | **208.5** | 224.6 |
| Investment in partnership | **80.8** | 56.4 |
| Goodwill write-down | **16.0** | 107.5 |
| Net operating loss carryforward | **158.8** | – |
| Other | **134.7** | 145.7 |
| Total deferred income tax assets | **$ 1,379.1** | $1,051.5 |
| Deferred income tax liabilities [(1)] | | |
| Property related | **$ (557.6)** | $ (521.8) |
| Basis difference in oil and gas properties | **–** | 4.4 |
| Other | **53.5** | 19.4 |
| Total deferred income tax liabilities | **$ (504.1)** | $ (498.0) |
| Net deferred tax assets | **$ 875.0** | $ 553.5 |

(1) Certain property related assets and liabilities have been netted.

Included in the "Property related" component of the deferred tax asset, as of Dec. 31, 2004, is the impact of the asset impairments discussed in **Notes 18** and **21.**

At Dec. 31, 2004 the company has unused federal and state (Florida) net operating losses of approximately $413.0 million and $259.0 million, respectively, expiring in 2024. In addition, the company has available alternative minimum tax credit carryforwards for tax purposes of approximately $208 million which may be used indefinitely to reduce federal income taxes.

**Effective Income Tax Rate**

| *(millions)* *For the years ended Dec. 31,* | *2004* | *2003* | *2002* |
|---|---|---|---|
| Net (loss) income from continuing operations before minority interest | **$(483.9)** | $ 12.9 | $ 268.5 |
| *Plus:* minority interest | **79.5** | 48.8 | – |
| Net (loss) income from continuing operations | **(404.4)** | 61.7 | 268.5 |
| Total income tax provision (benefit) | **(265.1)** | (91.5) | (56.9) |
| (Loss) income from continuing operations before income taxes | **(669.5)** | (29.8) | 211.6 |
| Income taxes on above at federal statutory rate of 35% | **(234.4)** | (10.4) | 74.1 |
| Increase (decrease) due to | | | |
| State income tax, net of federal income tax | **(22.4)** | (6.3) | 3.3 |
| Foreign income taxes | **(0.8)** | 7.5 | 1.0 |
| Amortization of investment tax credits | **(2.9)** | (4.7) | (4.8) |
| Permanent reinvestment – foreign income | **(10.5)** | (12.3) | (8.1) |
| Non-conventional fuels tax credit | – | (66.0) | (107.3) |
| AFUDC equity | **(0.3)** | (6.9) | (8.7) |
| Dividend income | **14.6** | – | – |
| Other | **(8.4)** | 7.6 | (6.4) |
| Total income tax provision from continuing operations | **$(265.1)** | $ (91.5) | $ (56.9) |
| Provision for income taxes as a percent of income from continuing operations, before income taxes | **39.6%** | 307.1% (1) | (26.9%) |

(1) This calculation is not necessarily meaningful as a result of the interaction between tax losses and tax credits for the period.

We have experienced a number of events that have impacted the overall effective tax rate on continuing operations. These events included the recognition of non-conventional fuel credits, permanent reinvestment of foreign income under Accounting Principles Board Opinion No. 23, *Accounting for Taxes - Special Areas,* (APB 23), repatriation of foreign source income to the United States resulting in the discontinuance of the permanent reinvestment criteria for certain investments under APB 23, Guatemalan tax reform effective Jul. 1, 2004, and equity treatment of variable interest entities as required under FIN 46R.

At Dec. 31, 2004, the portion of cumulative undistributed earnings from our investments in EEGSA was approximately $42 million. Since these earnings have been and are intended to be indefinitely reinvested in foreign operations, no provision has been made for U.S. taxes or foreign withholding taxes that may be applicable upon an actual or deemed repatriation.

The consolidated entity recorded a net state benefit in 2004 to reflect state deferred balances at the expected realizable rate which is lower than in prior years and to record estimated state benefits from impairments.

The provision for income taxes as a percent of income from discontinued operations was 34.4%, 36.2% and 17.0%, respectively, in 2004, 2003, and 2002. The total effective income tax rate differs from the federal statutory rate due to state income tax, net of federal income tax, the non-conventional fuels tax credit and other miscellaneous items. The actual cash paid for income taxes as primarily required for the alternative minimum tax, state income taxes and payments for prior year audits in 2004, 2003 and 2002 was $22.4 million, $58.8 million and $71.9 million, respectively.

## 5. Employee Postretirement Benefits

### Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings. The company's policy is to fund the plan based on the amount determined by the company's actuaries within the guidelines set by ERISA for the minimum annual contribution. In 2004, the company made a contribution of $14.2 million to the plan. In 2005, the company expects to make a contribution of about $13.6 million.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plans. These are non-qualified, non-contributory defined benefit retirement plans available to certain members of senior management. In 2004, the company made a contribution of $9.8 million to these plans. In 2005, the company expects to make a contribution of about $4.6 million to these plans.

TECO Energy reported other comprehensive income of $7.2 million in 2004 and other comprehensive losses of $43.9 million and $4.4 million in 2003 and 2002, respectively, related to adjustments to the minimum pension liability associated with these pension plans (See **Note 10**).

The asset allocation for the company's pension plan as of Sep. 30, 2004 and 2003, the measurement dates for the company's postretirement benefit plans, and the target allocation for 2005, by asset category, follows:

**Asset Allocation**

| *Asset category* | *Target Allocation for 2005* | *Percentage of Plan Assets at Sep. 30, 2004* | *2003* |
|---|---|---|---|
| Equities | 55% – 60% | 60% | 57% |
| Fixed income | 40% – 45% | 40% | 43% |
| Total | | 100% | 100% |

The company's investment objective is to obtain above-average returns while minimizing volatility of expected returns over the long term. The target equities/fixed income mix is designed to meet investment objectives. The company's strategy is to hire proven managers and allocate assets to reflect a mix of investment styles, emphasize preservation of principal to minimize the impact of declining markets, and stay fully invested except for cash to meet benefit payment obligations and plan expenses.

The assumptions for the expected return on plan assets were developed based on an analysis of historical market returns, the plan's past experience and current market conditions.

### Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 meeting certain service requirements. The company contribution toward health care coverage for most employees who retired after the age of 55 between Jan. 1, 1990 and Jun. 30, 2001 is limited to a defined dollar benefit based on age and service. The company contribution toward pre-65 and post-65 health care coverage for most employees retiring on or after Jul. 1, 2001 is limited to a defined dollar benefit based on a service schedule. In 2005, the company expects to make a contribution of about $9.8 million to this program. Postretirement benefit levels are substantially unrelated to salary. The company reserves the right to terminate or modify the plans in whole or in part at any time.

On Dec. 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the MMA) was signed into law. Beginning in 2006, the new law adds prescription drug coverage to Medicare, with a 28% tax-free subsidy to encourage employers to retain their prescription drug programs for retirees, along with other key provisions. TECO Energy's current retiree medical program for those eligible for Medicare (generally over age 65) includes coverage for prescription drugs.

On May 19, 2004, the FASB issued FSP 106-2, *Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003* (FSP 106-2), which supersedes FSP 106-1 and was effective for the period beginning Jul. 1, 2004 for the company. The guidance in FSP 106-2 related to the accounting for the federal subsidy applies only to the sponsor of a single-employer defined-dollar-benefit postretirement health care plan for which (a) the employer has concluded that prescription drug benefits available under the plan to some or all participants for some or all future years are "actuarially equivalent" to Medicare Part D and thus qualify for the subsidy under the MMA and (b) the expected federal subsidy will offset or reduce the employer's share of the cost of the underlying postretirement prescription drug coverage on which the federal subsidy is based. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan will at least be "actuarially equivalent" to the standard drug benefits to be offered under Medicare Part D. As a result, the company calculated the incremental effect of the Medicare subsidy and the related assumption changes on its accumulated postretirement benefit obligation as of Jan. 1, 2004, to be a reduction of $27.0 million. The expected subsidy reduced the net periodic benefit cost for 2004 by $2.8 million.

The company is continuing to analyze what, if any, plan design changes should be made with respect to the company's retiree medical program in response to the MMA.

The following charts summarize the income statement and balance sheet impact, as well as the benefit obligations, assets, funded status and rate assumptions associated with the pension and other postretirement benefits.

**Benefit Expense**

| *(millions)* | *Pension Benefits* | | | *Other Postretirement Benefits* | | |
|---|---|---|---|---|---|---|
| *For the years ended Dec. 31,* | *2004* | *2003* | *2002* | *2004* | *2003* | *2002* |
| **Components of net periodic benefit expense** | | | | | | |
| Service cost (benefits earned during the period) | **$ 17.0** | $ 14.3 | $ 11.8 | **$ 4.3** | $ 4.2 | $ 3.5 |
| Interest cost on projected benefit obligations | **33.0** | 30.8 | 28.7 | **10.8** | 12.5 | 11.2 |
| Expected return on assets | **(39.1)** | (42.1) | (42.9) | **–** | – | – |
| Amortization of: | | | | | | |
| Transition obligation (asset) | **(1.1)** | (1.1) | (1.1) | **2.7** | 2.7 | 2.7 |
| Prior service cost (benefit) | **(0.5)** | (0.5) | (0.5) | **1.8** | 1.8 | 1.9 |
| Actuarial (gain) loss | **2.7** | 1.4 | (3.7) | **0.7** | 1.5 | 0.1 |
| Pension expense (benefit) | **12.0** | 2.8 | (7.7) | **20.3** | 22.7 | 19.4 |
| Special termination benefit charge | **–** | – | 2.7 | **–** | – | 0.6 |
| Settlement | **6.6** | – | – | **–** | – | – |
| Additional amounts recognized | **0.4** | – | – | **–** | 0.1 | – |
| Net pension expense (benefit)recognized in the Consolidated Statements of Income | **$ 19.0** | $ 2.8 | $ (5.0) | **$ 20.3** | $ 22.8 | $ 20.0 |
| **Assumptions used to determine net cost** | | | | | | |
| Discount rate | **6.00%** | 6.75% | 7.50% | **6.00%** | 6.75% | 7.50% |
| Rate of compensation increase | **4.25%** | 4.82% | 4.66% | **4.25%** | 4.82% | 4.66% |
| Expected return on plan assets | **8.75%** | 9.00% | 9.00% | **N/A** | N/A | N/A |

The following table shows the funded status of the qualified and non-qualified pension plans for which the projected obligation exceeds the fair value of the plan assets:

**Pension Plans – Projected Obligation Exceeds Plan Assets**

| *(millions) Sep. 30,* | *2004* | *2003* |
|---|---|---|
| Projected benefit obligation | **$ 545.4** | $ 554.5 |
| Fair value of plan assets | **407.6** | 391.8 |
| Projected obligation in excess of plan assets | **$ 137.8** | $ 162.7 |

As of Sep. 30, 2004 and 2003, for the qualified and non-qualified pension plans, the accumulated obligation exceeded the fair value of the plan assets. The table below shows the funded status for the respective plans:

**Pension Plans – Accumulated Obligation Exceeds Plan Assets**

| *(millions) Sep. 30,* | *2004* | *2003* |
|---|---|---|
| Accumulated benefit obligation | **$ 476.2** | $ 480.0 |
| Fair value of plan assets | **407.6** | 391.8 |
| Accumulated obligation in excess of plan assets | **$ 68.6** | $ 88.2 |

The accumulated postretirement benefit obligation exceeds plan assets for the postretirement health and welfare benefits plan.

**Employee Postretirement Benefits**

| (millions) | Pension Benefits 2004 | Pension Benefits 2003 | Other Postretirement Benefits 2004 | Other Postretirement Benefits 2003 |
|---|---|---|---|---|
| **Change in benefit obligation** | | | | |
| Net benefit obligation at prior measurement date | **$ 554.5** | $ 455.1 | **$ 198.7** | $ 184.6 |
| Service cost | **17.0** | 14.3 | **4.3** | 4.2 |
| Interest cost | **33.0** | 30.8 | **10.8** | 12.5 |
| Plan participants' contributions | **–** | – | **3.5** | 1.4 |
| Actuarial loss | **(0.9)** | 89.7 | **(34.3)** | 6.5 |
| Plan amendments | **1.5** | – | **17.0** | – |
| Special termination benefits | **–** | – | **–** | – |
| Curtailment | **(2.2)** | (1.9) | **–** | – |
| Gross benefits paid | **(57.5)** | (33.5) | **(14.3)** | (10.5) |
| Net benefit obligation at measurement date | **$ 545.4** | $ 554.5 | **$ 185.7** | $ 198.7 |
| **Change in plan assets** | | | | |
| Fair value of plan assets at prior measurement date | **$ 391.8** | $ 371.9 | **$ –** | $ – |
| Actual return on plan assets | **43.0** | 51.7 | **–** | – |
| Employer contributions | **30.3** | 1.7 | **10.8** | 9.1 |
| Plan participants' contributions | **–** | – | **3.5** | 1.4 |
| Gross benefits paid | **(57.5)** | (33.5) | **(14.3)** | (10.5) |
| Fair value of plan assets at measurement date | **$ 407.6** | $ 391.8 | **$ –** | $ – |
| **Funded status** | | | | |
| Fair value of plan assets | **$ 407.6** | $ 391.8 | **$ –** | $ – |
| Benefit obligation | **545.4** | 554.5 | **185.7** | 198.7 |
| Funded status at measurement date | **(137.8)** | (162.7) | **(185.7)** | (198.7) |
| Net contributions after measurement date | **0.4** | 6.7 | **2.8** | 2.4 |
| Unrecognized net actuarial loss | **149.2** | 165.6 | **12.4** | 47.4 |
| Unrecognized prior service cost (benefit) | **(5.4)** | (6.9) | **35.6** | 20.5 |
| Unrecognized net transition obligation (asset) | **(0.2)** | (1.4) | **22.0** | 24.7 |
| Accrued liability at end of year | **$ 6.2** | $ 1.3 | **$(112.9)** | $(103.7) |
| **Amounts recognized in the statement of financial position** | | | | |
| Prepaid benefit cost | **$ 23.6** | $ 16.9 | **$ –** | $ – |
| Accrued benefit cost | **(17.4)** | (15.7) | **(112.9)** | (103.7) |
| Additional minimum liability | **(74.4)** | (82.7) | **–** | – |
| Intangible asset | **2.2** | 1.3 | **–** | – |
| Accumulated other comprehensive income | **72.2** | 81.5 | **–** | – |
| Net amount recognized at end of year | **$ 6.2** | $ 1.3 | **$(112.9)** | $(103.7) |
| **Assumptions used in determining benefit obligations, end of year** | | | | |
| Discount rate to determine projected benefit obligation | **6.00%** | 6.00% | **6.00%** | 6.00% |
| Rate of increase in compensation levels | **4.25%** | 4.25% | **4.25%** | 4.25% |

Employer contributions and benefits paid in the above table include both those amounts contributed directly to, and paid directly from both plan assets and directly to plan participants. The assumed health care cost trend rate for medical costs was 10.5% and 11.5% in 2004 and 2003, respectively, and decreases to 5.0% in 2013 and thereafter.

A 1% increase in the medical trend rates would produce an 8% ($1.2 million) increase in the aggregate service and interest cost for 2004 and a 5% ($8.5 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2004, the measurement date.

A 1% decrease in the medical trend rates would produce a 6% ($0.9 million) decrease in the aggregate service and interest cost for 2004 and a 3% ($6.3 million) decrease in the accumulated postretirement benefit obligation as of Sep. 30, 2004, the measurement date.

Information about expected benefit payments for the pension and postretirement benefit plans follows:

**Expected Benefit Payments**
**(including projected service and net of employee contributions)**

| (millions) For the years ended Dec. 31, | Pension Benefits | Other Benefits (exclusive of subsidy payments under MMA) | Employer Value of Expected Payments MMA | Other Benefits net of Expected Payments under MMA |
|---|---|---|---|---|
| 2005 | $ 34.9 | $ 9.8 | $ – | $ 9.8 |
| 2006 | $ 32.5 | $ 10.5 | $ (0.7) | $ 9.8 |
| 2007 | $ 33.3 | $ 11.4 | $ (0.8) | $ 10.6 |
| 2008 | $ 34.5 | $ 12.2 | $ (0.9) | $ 11.3 |
| 2009 | $ 37.8 | $ 13.0 | $ (0.9) | $ 12.1 |
| 2010-2014 | $ 222.4 | $ 75.8 | $ (4.9) | $ 70.9 |

## 6. Short-Term Debt

At Dec. 31, 2004 and 2003, the following credit facilities and related borrowings existed:

**Credit Facilities**

| | Dec. 31, 2004 | | | Dec. 31, 2003 | | |
|---|---|---|---|---|---|---|
| *(millions)* | *Credit Facilities* | *Borrowings Outstanding*[1] | *Letters of Credit Outstanding* | *Credit Facilities* | *Borrowings Outstanding*[1] | *Letters of Credit Outstanding* |
| Tampa Electric: | | | | | | |
| 1-year facility | $ – | $ – | $ – | $ 125.0 | $ – | $ – |
| 3-year facility | 150.0 | 115.0 | – | – | – | – |
| 3-year facility | 125.0 | – | – | 125.0 | – | – |
| TECO Energy: | | | | | | |
| 18-month facility | – | – | – | 100.0 | – | – |
| 1-year facility | – | – | – | 37.5 | 37.5 | – |
| 3-year facility | 200.0 | – | 27.4 | 350.0 | – | 109.9 |
| **Total** | $ 475.0 | $ 115.0 | $ 27.4 | $ 737.5 | $ 37.5 | $ 109.9 |

(1) Borrowings outstanding are reported as notes payable.

These credit facilities require commitment fees ranging from 17.5 to 50.0 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2004 and 2003 was 3.32% and 6.63%, respectively.

*TECO Energy Credit Facility*

On Jul. 6, 2004, TECO Energy completed its new $200 million bank credit facility upon cancellation of its existing $350 million credit facility. The new facility has a three-year term and is secured by the stock of TECO Transport. The security will be released if TECO Energy achieves investment-grade ratings and stable outlooks from both Moody's and Standard & Poor's. This facility includes a $100 million sub-limit for letters of credit. The new facility requires that at the end of each quarter the ratio of debt to earnings before interest, taxes, depreciation and amortization (EBITDA), as defined in the agreement, not exceed 5.25 times through Dec. 30, 2005, 5.00 times from Dec. 31, 2005 through Dec. 30, 2006 and 4.90 times from and after Dec. 31, 2006, and TECO Energy's EBITDA to interest coverage ratio, as defined in the agreement, to be not less than 2.25 times through Dec. 30, 2005 and 2.60 times thereafter. It does not have a debt to total capital covenant. The new facility places certain limitations on the ability to sell core assets and limits the ability of TECO Energy and certain of its subsidiaries, excluding Tampa Electric, to issue additional indebtedness in excess of $100 million, unless the indebtedness refinances currently outstanding indebtedness or meets certain other conditions. The new facility also provides that, in the event the aggregate quarterly dividend payments on TECO Energy common stock were to equal or exceed $50 million, TECO Energy would not be able to declare or pay cash dividends on the common stock or make certain other distributions unless it had previously delivered liquidity projections satisfactory to the administrative agent under the credit facility demonstrating that TECO Energy will have sufficient cash to pay such dividends and distributions and the three succeeding quarterly dividends.

*Tampa Electric $150 million Credit Facility*

On Oct. 22, 2004, Tampa Electric replaced its $125 million credit facility maturing Nov. 5, 2004 with a $150 million credit facility maturing Oct. 22, 2007. The facility requires that at the end of each quarter the ratio of debt to total capital not exceed 60% and that the ratio of EBITDA to interest not be less than 2.0 times. The new facility does not include the restriction on distributions included in the former facility. Also, Tampa Electric's existing $125 million facility maturing Nov. 6, 2006 was amended to eliminate the restriction on distributions and conform the financial covenants requirements to the new facility levels.

*Repayment of $37.5 million TECO Energy Credit Facility*

On Jan. 5, 2004, TECO Energy repaid $20 million of the $37.5 million one-year credit facility collateralized by the Union and Gila River assets. On Feb. 4, 2004, TECO Energy repaid the remaining $17.5 million of the credit facility.

## 7. Long-Term Debt

At Dec. 31, 2004, total long-term debt, excluding amounts currently due, had a carrying amount of $3,880.0 million and an estimated fair market value of $4,203.7 million. The estimated fair market value of long-term debt was based on quoted market prices for the same or similar issues, on the current rates offered for debt of the same remaining maturities, or for long-term debt issues with variable rates that approximate market rates, at carrying amounts.

A substantial part of the tangible assets of Tampa Electric is pledged as collateral to secure its first mortgage bonds, and certain pollution control equipment is pledged to secure certain installment contracts payable. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.

TECO Energy's maturities and annual sinking fund requirements of long-term debt for 2005 through 2009 and thereafter are as follows:

**Long-Term Debt Maturities For Continuing Operations**

| *Dec. 31, 2004 (millions)* | *2005* | *2006* | *2007* | *2008* | *2009* | *Thereafter* | *Total Long-term Debt* |
|---|---|---|---|---|---|---|---|
| TECO Energy | | | | | | | |
| Debt securities | $ – | $ – | $ 680.0 | $ – | $ – | $1,300.0 | $ 1,980.0 |
| Junior subordinated notes | – | – | 71.4 | – | – | 206.2 | 277.6 |
| Tampa Electric | – | – | 125.0 | – | – | 1,223.9 | 1,348.9 |
| Peoples Gas | 5.5 | 5.9 | 31.1 | 5.7 | 5.5 | 120.5 | 174.2 |
| TECO Transport | – | – | 110.6 | – | – | – | 110.6 |
| Other | 8.1 | 10.8 | 0.9 | 0.8 | 0.9 | – | 21.5 |
| Total long-term debt maturities | $ 13.6 | $ 16.7 | $1,019.0 | $ 6.5 | $ 6.4 | $2,850.6 | $ 3,912.8 |

**Debt**

*TECO Energy – $300 million 7.5% Senior Unsecured Notes*

On Jun. 13, 2003, TECO Energy issued $300 million of 7.5% Senior Unsecured Notes due in 2010. Net proceeds of $293 million were used to repay short-term debt and for general corporate purposes. See **Note 12** for a summary of significant financial covenants and performance against these covenant requirements.

*TECO Energy – $380 million 10.5% Senior Unsecured Notes*

In November 2002, the proceeds from the issuance of TECO Energy notes were used for general corporate purposes and to pay the $34.1 million option premium associated with the refinancing of $200 million of notes. The $34.1 million option premium ($20.9 million after tax) was recognized as a charge in 2002. See **Note 12** for a summary of significant financial covenants and performance against these covenant requirements.

*Tampa Electric – $250 million 6.25% Senior Notes*

In April 2003, Tampa Electric issued $250 million of 6.25% Senior Notes due 2014-2016, in a private placement. Net proceeds of approximately $250 million were used to repay short-term indebtedness and for general corporate purposes at Tampa Electric. See **Note 12** for a summary of significant financial covenants and performance against these covenant requirements.

**Junior Subordinated Notes**

As a result of the adoption of FAS 150 on Jul. 1, 2003, the preferred securities issued by the company were reclassified and presented as long-term debt for external financial reporting purposes. The cumulative effect of the adoption of FAS 150 was an after-tax loss of $3.2 million ($5.3 million pretax), reflecting an adjustment to recognize interest expense ratably over the life of the instruments in accordance with the new guidance.

Effective Jan. 1, 2004, TECO Energy adopted FIN 46R. As a result, the company's preferred securities were no longer recognized as a result of the deconsolidation of the funding companies established to issue the securities purchases by the trusts described below. As described below, the company issued junior subordinated notes to the funding companies in connection with the issuance of the trust preferred securities. The company has reflected the junior subordinated notes and the equity investment in the funding companies on the balance sheet. See **Note 2** for additional discussion of the impact of FIN 46R.

*Capital Trust I*

In Dec. 2000, TECO Capital Trust I, a trust established for the sole purpose of issuing Trust Preferred Securities (TRuPS) and purchasing company preferred securities, issued 8 million shares of $25 par, 8.5% TRuPS, due 2041, with an aggregate liquidation value of $200 million. Each TRuPS represents an undivided beneficial interest in the assets of the Trust. The TRuPS represent an indirect interest in a corresponding amount of the TECO Energy 8.5% junior subordinated notes due 2041. Distributions are payable quarterly in arrears on Jan. 31, Apr. 30, Jul. 31, and Oct. 31 of each year. Distributions were $17.0 million in 2004, 2003 and 2002. For 2004, these distributions were reflected in interest expense.

The junior subordinated notes may be redeemed at the option of TECO Energy at any time on or after Dec. 20, 2005 at 100% of their principal amount plus accrued interest through the redemption date. Upon any liquidation of the company preferred securities, holders of the TRuPS would be entitled to the liquidation preference of $25 per share plus all accrued and unpaid dividends through the date of redemption.

*Capital Trust II*

In January 2002, TECO Energy sold 17.965 million mandatorily convertible equity security units in the form of 9.5% equity units at $25 per unit resulting in $436 million of net proceeds. Each equity unit consisted of $25 in principal amount of a trust preferred security of TECO Capital Trust II, a Delaware business trust formed for the purpose of issuing these securities, with a stated liquidation amount of $25 and a contract to purchase shares of common stock of TECO Energy in January 2005 at a price per share of between $26.29 and $30.10 based on the market price at that time. For the terms of the final settlement see **Note 23**. The equity units represent an indirect interest in a corresponding amount of the TECO Energy 5.11% junior subordinated notes. The holders of these contracts were entitled to quarterly contract adjustment payments at the annualized rate of 4.39% of the stated amount of $25 per year through and including Jan. 15, 2005.

In August 2004, the company exchanged approximately 10.227 million common shares and $14.9 million in cash for 10.756 million units through an early settlement offer (see **Note 9**). After the acceptance of the early settlement offer, approximately 7.209 million units remained outstanding. If these remaining equity units had been converted as of Dec. 31, 2004, the company would have been required to issue approximately 6.85 million shares of common stock to satisfy the mandatory conversion obligation. This was also the maximum number of shares issuable under the conversion feature.

In October 2004, $162.7 million of TECO Capital Trust II trust preferred securities out of a total $180.2 million aggregate stated liquidation amount of such trust preferred securities outstanding were remarketed. The distribution rate on the trust preferred securities was reset to a coupon rate of 5.934% per annum, payable quarterly, effective on and after Oct. 16, 2004.

At the closing of the remarketing on Oct. 15, 2004, the company purchased approximately $122.7 million of the trust preferred securities that were remarketed and retired the trust preferred securities it purchased. The company funded its participation by borrowing $124.1 million under an unsecured bridge loan facility with JP Morgan Chase Bank and Merrill Lynch Bank USA. The company received the proceeds of this loan on Oct. 15, 2004 and repaid the loan on Dec. 23, 2004 with the proceeds from the sale of Frontera Generation Limited Partnership (see **Note 16**).

At Dec. 31, 2004 and 2003, TECO Energy had the following long-term debt outstanding:

| **Long-Term Debt** *(millions) Dec. 31,* | | *Due* | *2004* | *2003* |
|---|---|---|---|---|
| **TECO Energy** | Notes: 7.2% (effective rate of 7.38%) [1] | 2011 | $ 600.0 | $ 600.0 |
| | 6.125% (effective rate of 6.31%) [1] | 2007 | 300.0 | 300.0 |
| | 7% (effective rate of 7.08%) [1] | 2012 | 400.0 | 400.0 |
| | 10.5% (effective rate of 12.37%) [1][2] | 2007 | 380.0 | 380.0 |
| | 7.5% (effective rate of 7.85%) [1][2] | 2010 | 300.0 | 300.0 |
| | Junior subordinated notes: 8.50% [3] | 2041 | 206.2 | – |
| | 5.93% [4] | 2007 | 71.4 | – |
| | Preferred Securities: 8.5% [14] | 2041 | – | 200.0 |
| | 9.5% [14] | 2007 | – | 449.1 |
| | | | 2,257.6 | 2,629.1 |
| **Tampa Electric** | First mortgage bonds (issuable in series): | | | |
| | 7.75% (effective rate of 7.96% for 2003) | 2022 | – | 75.0 |
| | Installment contracts payable: [5] | | | |
| | 6.25% Refunding bonds (effective rate of 6.81%) [1][6] | 2034 | 86.0 | 86.0 |
| | 5.85% Refunding bonds (effective rate of 5.88%) | 2030 | 75.0 | 75.0 |
| | 5.1% Refunding bonds (effective rate of 5.75%) [7] | 2013 | 60.7 | 60.7 |
| | 5.5% Refunding bonds (effective rate of 6.32%) [7] | 2023 | 86.4 | 86.4 |
| | 4% (effective rate of 4.19%) [8] | 2025 | 51.6 | 51.6 |
| | 4% (effective rate of 4.16%) [8] | 2018 | 54.2 | 54.2 |
| | 4.25% (effective rate of 4.44%) [8] | 2020 | 20.0 | 20.0 |
| | Notes: 6.875% (effective rate of 6.98%) [1] | 2012 | 210.0 | 210.0 |
| | 6.375% (effective rate of 7.35%) [1] | 2012 | 330.0 | 330.0 |
| | 5.375% (effective rate of 5.59%) [1] | 2007 | 125.0 | 125.0 |
| | 6.25% (effective rate of 6.31%) [1][2] | 2014 - 2016 | 250.0 | 250.0 |
| | | | 1,348.9 | 1,423.9 |
| **Peoples Gas System** | Senior Notes: [1][2] 10.35% | 2005-2007 | 2.6 | 3.4 |
| | 10.33% | 2005-2008 | 4.0 | 4.8 |
| | 10.3% | 2005-2009 | 5.6 | 6.4 |
| | 9.93% | 2005-2010 | 5.8 | 6.6 |
| | 8% | 2005-2012 | 21.2 | 23.3 |
| | Notes: 6.875% (effective rate of 6.98%) [1] | 2012 | 40.0 | 40.0 |
| | 6.375% (effective rate of 7.35%) [1] | 2012 | 70.0 | 70.0 |
| | 5.375% (effective rate of 5.59%) [1] | 2007 | 25.0 | 25.0 |
| | | | 174.2 | 179.5 |
| **TWG-Merchant** | Non-recourse secured facility notes, variable rate: | | | |
| | 8.13% for 2004 and 3.00% for 2003 [9][10][11] | 2004 | 1,395.0 | 1,395.0 |
| | Non-recourse financing facility - Union County: 7.5% [5][10] | 2005-2021 | 676.1 | 692.3 |
| | | | 2,071.1 | 2,087.3 |
| **Other Unregulated** | Dock and wharf bonds, 5% [5] | 2007 | 110.6 | 110.6 |
| | Non-recourse mortgage notes, variable rate: | | | |
| | 5.43% for 2004 and 4.45% for 2003 [12] | 2005 | 4.1 | 4.6 |
| | 3.95% for 2003 (effective rate of 4.16%) [12] | 2004 | – | 3.0 |
| | 4.78% (effective rate of 5.09%) [13] | 2005-2006 | 13.0 | – |
| | Non-recourse secured facility notes, variable rate: | | | |
| | 4.38% for 2003 [9] | 2004 | – | 36.7 |
| | 6.63% for 2004 and 2003 [9] | 2005-2009 | 4.4 | 16.0 |
| | 4.75% for 2003 [9] | 2004 | – | 14.0 |
| | Non-recourse secured facility notes: 10.1% | 2004 | – | 15.3 |
| | 9.629% | 2004 | – | 19.1 |
| | | | 132.1 | 219.3 |
| Unamortized debt (discount), net | | | (19.2) | (27.6) |
| | | | 5,964.7 | 6,511.5 |
| Less amount due within one year | | | 13.6 | 31.6 |
| Less long-term liabilities held for sale [10] | | | 2,071.1 | 2,087.3 |
| Total long-term debt | | | $3,880.0 | $4,392.6 |

(1) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(2) These long-term debt agreements contain various restrictive financial covenants (see **Note 12**).
(3) These securities may be redeemed in whole or in part, at par by action of the company on or after Dec. 20, 2005.
(4) The rate on these securities was reset from 5.11% (effective rate of 5.85%) to 5.93% on Oct. 15, 2004. These securities, along with the forward purchase contract to purchase the company's common stock, comprise the mandatorily convertible equity security units of TECO Capital Trust II.
(5) Tax-exempt securities.
(6) Proceeds of these bonds were used to refund bonds with an interest rate of 9.9% in February 1995. For accounting purposes, interest expense has been recorded using a blended rate of 6.52% on the original and refunding bonds, consistent with regulatory treatment.
(7) Proceeds of these bonds were used to refund bonds with interest rates of 5.75%-8%.
(8) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(9) Composite year-end interest rate.
(10) This obligation is expected to be transferred in the disposition of the Union and Gila River power plants. As a result, the liability has been reclassified to "Liabilities associated with assets held for sale". See **Note 21** and **Note 23** for additional details.
(11) These notes were in default as of Dec. 31, 2004. See **Note 12**.
(12) These notes represent 100% of the debt for BT-One, LLC, an 80% owned consolidated affiliate. In total, the company has a $1.0 million guarantee on these notes.
(13) These notes represent 100% of the debt for Hernando Oaks, LLC, a 50% owned consolidated affiliate. In total, the company has a $9.2 million guarantee on these notes.
(14) As a result of the adoption of FIN46R, effective Jan. 1, 2004, the preferred securities are no longer recognized on the Consolidated Balance Sheet.

## 8. Preferred Stock

**Preferred stock of TECO Energy – $1 par**
10 million shares authorized, none outstanding.
**Preference stock (subordinated preferred stock) of Tampa Electric – no par**
2.5 million shares authorized, none outstanding.
**Preferred stock of Tampa Electric – no par**
2.5 million shares authorized, none outstanding.
**Preferred stock of Tampa Electric – $100 par**
1.5 million shares authorized, none outstanding.

## 9. Common Stock

**Stock-Based Compensation**

In April 2004, the shareholders approved the 2004 Equity Incentive Plan (2004 Plan). The 2004 Plan superseded the 1996 Equity Incentive Plan (1996 Plan), and no additional grants will be made under the 1996 Plan. The rights of the holders of the outstanding options under the 1996 Plan were not affected. The purpose of the 2004 Plan is to attract and retain key employees and consultants of the company, to provide an incentive for them to achieve long-range performance goals and to enable them to participate in the long-term growth of the company. The 2004 Plan amended the 1996 Plan to increase the number of shares of common stock subject to grants by 10,000,000 shares, place various limitations on the types of awards available to be granted, specify a ten-year term for the 2004 Plan and any grants made thereunder and allow awards to consultants of the company. Under the 2004 Plan, the Compensation Committee of the Board of Directors may award stock grants, stock options and / or stock equivalents to officers, key employees and consultants of TECO Energy and its subsidiaries.

The Compensation Committee has discretion to determine the terms and conditions of each award, which may be subject to conditions relating to continued employment, restrictions on transfer or performance criteria.

Under the 2004 Plan and the 1996 Plan (collectively referred to as the "Equity Plans"), 2.4 million, 2.8 million and 1.8 million stock options were granted to employees in 2004, 2003 and 2002, respectively, each with a maximum term of 10 years. The weighted average fair value per share of stock options granted to employees under the Equity Plans in 2004, 2003, and 2002, respectively, was $2.80, $1.79 and $4.90, using the Black-Scholes option pricing model with assumptions as described in **Note 1**. In addition, 0.3 million, 0.6 million and 0.3 million shares of restricted stock were awarded in 2004, 2003 and 2002, respectively, with weighted average fair values of $13.30, $11.14 and $27.97, respectively.

Compensation expense recognized for stock grants awarded under the 2004 Plan and the 1996 Plan was $5.2 million, $1.6 million and $1.7 million in 2004, 2003 and 2002, respectively. Approximately half of the stock grants awarded in 2004, 2003 and 2002 are performance shares, restricted subject to meeting specified total shareholder return goals, vesting in three years with final payout ranging from zero to 200% of the original grant. Adjustments are made to reflect contingent shares which could be issuable based on current period results. The consolidated balance sheets at Dec. 31, 2004 and 2003 reflected a $(0.5) million and a $(4.7) million liability, respectively, classified as other deferred credits, for these contingent shares. The remaining stock grants are restricted subject to continued employment generally, with the majority of the 2004, 2003 and 2002 stock grants vesting in three years, and the 1997 and 1996 stock grants vesting at normal retirement age.

Stock option transactions during the last three years under the Equity Plans are summarized as follows:

**Stock Options - Equity Plans**

| | *Option Shares (thousands)* | *Weighted Avg. Option Price* |
|---|---|---|
| Balance at Dec. 31, 2001 | 5,190 | $24.79 |
| Granted | 1,770 | $27.97 |
| Exercised | (487) | $20.93 |
| Cancelled | (57) | $27.03 |
| Balance at Dec. 31, 2002 | 6,416 | $25.94 |
| Granted | 2,829 | $11.10 |
| Exercised | (14) | $11.09 |
| Cancelled | (306) | $23.35 |
| Balance at Dec. 31, 2003 | 8,925 | $21.35 |
| Granted | 2,388 | $13.44 |
| Exercised | (512) | $11.17 |
| Cancelled | (489) | $22.87 |
| Balance at Dec. 31, 2004 | **10,312** | **$19.95** |
| Exercisable at Dec. 31, 2004 | **741** | **$11.09** |
| Available for future grant at Dec. 31, 2004 | **9,456** | |

As of Dec. 31, 2004, the 10.3 million options outstanding under the Equity Plans are summarized below.

**Stock Options Outstanding at Dec. 31, 2004**

| *Option Shares (thousands)* | *Range of Option Prices* | *Weighted Avg. Option Price* | *Weighted Avg. Remaining Contractual Life* |
|---|---|---|---|
| 4,577 | $11.09 - $13.50 | $12.30 | 9 Years |
| 1,917 | $20.75 - $22.48 | $21.27 | 4 Years |
| 493 | $23.55 - $25.97 | $24.09 | 2 Years |
| 3,325 | $27.56 - $31.58 | $29.11 | 6 Years |

In April 1997, the Shareholders approved the 1997 Director Equity Plan (1997 Plan), as an amendment and restatement of the 1991 Director Stock Option Plan (1991 Plan). The 1997 Plan superseded the 1991 Plan, and no additional grants will be made under the 1991 Plan. The rights of the holders of outstanding options under the 1991 Plan will not be affected. The purpose of the 1997 Plan is to attract and retain highly qualified non-employee directors of the company and to encourage them to own shares of TECO Energy common stock. The 1997 Plan is administered by the Board of Directors. The 1997 Plan amended the 1991 Plan to increase the number of shares of common stock subject to grants by 250,000 shares, expanded the types of awards available to be granted and replaced the fixed formula grant by giving the Board discretionary authority to determine the amount and timing of awards under the plan.

Under the 1997 Plan, 5,000, 6,000 and 5,500 stock grants were awarded to directors in 2004, 2003 and 2002, respectively, with weighted average fair values of $13.56, $11.09 and $27.97, respectively. In addition, 35,000, 40,000 and 27,500 stock options were granted to directors in 2004, 2003 and 2002, respectively, each with a maximum term of 10 years. The weighted average fair value per share of stock options granted to directors under the 1997 Plan in 2004, 2003 and 2002, respectively, was $2.90, $1.49 and $4.90, using the Black-Scholes option pricing model with assumptions as described in **Note 1**. Stock option transactions during the last three years under the 1997 Plan are summarized as follows:

**Stock Options - Director Equity Plans**

| | *Option Shares (thousands)* | *Weighted Avg. Option Price* |
|---|---|---|
| Balance at Dec. 31, 2001 | 202 | $24.49 |
| Granted | 28 | $27.97 |
| Exercised | (22) | $20.95 |
| Cancelled | (2) | $27.56 |
| Balance at Dec. 31, 2002 | 206 | $25.31 |
| Granted | 40 | $11.72 |
| Exercised | – | – |
| Cancelled | (10) | $23.41 |
| Balance at Dec. 31, 2003 | 236 | $23.08 |
| Granted | 35 | $14.03 |
| Exercised | – | $ – |
| Cancelled | (8) | $19.81 |
| Balance at Dec. 31, 2004 | **263** | **$21.97** |
| Exercisable at Dec. 31, 2004 | **75** | **$12.80** |
| Available for future grant at Dec. 31, 2004 | **198** | |

As of Dec. 31, 2004, the 263,000 options outstanding under the 1997 Plan with option prices of $11.09 – $31.58, had a weighted average option price of $21.97 and a weighted average remaining contractual life of six years.

**Dividend Reinvestment Plan**

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised $5.1 million, $8.0 million and $11.2 million of common equity from this plan in 2004, 2003 and 2002, respectively.

**Common Stock and Treasury Stock**

In June 2002, the company completed a public offering of 15.525 million common shares at a price to the public of $23.00 per share. The sale of these shares resulted in net proceeds to the company of approximately $346.4 million, which were used to repay short-term debt and for general corporate purposes. In October 2002, the company issued 19.385 million common shares at a price to the public of $11.00 per share. The sale of these shares resulted in net proceeds to the company of approximately $206.8 million, which were used to repay short-term debt.

In September 2003, TECO Energy sold 11 million shares of common stock to funds managed by Franklin Advisers, Inc. at a price of $11.76 per share. Net proceeds of approximately $129 million were used to repay short-term indebtedness and for general corporate purposes.

On Aug. 25, 2004, the company completed an early settlement exchange offer of its TECO Capital Trust II Equity Security Units for 10.2 million shares of common stock (see Note 7 and Note 23)

**Shareholder Rights Plan**

In accordance with the company's Shareholder Rights Plan, a Right to purchase one additional share of the company's common stock at a price of $90 per share is attached to each outstanding share of the company's common stock. The Rights expire in May 2009, subject to extension. The Rights will become exercisable 10 business days after a person acquires 10% or more of the company's outstanding common stock or commences a tender offer that would result in such person owning 10% or more of such stock. If any person acquires 10% or more of the outstanding common stock, the rights of holders, other than the acquiring person, become rights to buy shares of common stock of the company (or of the acquiring company if the company is involved in a merger or other business combination and is not the surviving corporation) having a market value of twice the exercise price of each Right.

The company may redeem the Rights at a nominal price per Right until 10 business days after a person acquires 10% or more of the outstanding common stock.

**Employee Stock Ownership Plan**

Effective Jan. 1, 1990, TECO Energy amended the TECO Energy Group Retirement Savings Plan, a tax-qualified benefit plan available to substantially all employees, to include an employee stock ownership plan (ESOP). During 1990, the ESOP purchased 7 million shares of TECO Energy common stock on the open market for $100 million. The share purchase was financed through a loan from TECO Energy to the ESOP. This loan was at a fixed interest rate of 9.3% and was repaid from dividends on ESOP shares and from TECO Energy's contributions to the ESOP.

TECO Energy's contributions to the ESOP were $2.1 million, $21.1 million, and $13.6 million in 2004, 2003 and 2002, respectively. TECO Energy's annual contribution equals the interest accrued on the loan during the year plus additional principal payments needed to meet the matching allocation requirements under the plan, less dividends received on the ESOP shares. The components of net ESOP expense recognized for the past three years are as follows:

**ESOP Expense**

| *(millions)* <br> *For the years ended Dec. 31,* | *2004* | *2003* | *2002* |
|---|---|---|---|
| Interest expense | **$ 0.3** | $ 2.6 | $ 4.3 |
| Compensation expense | **8.4** | 16.0 | 12.2 |
| Dividends | **(4.0)** | (5.3) | (8.5) |
| Net ESOP expense | **$ 4.7** | $13.3 | $ 8.0 |

Compensation expense was determined by the shares allocated method.

At Dec. 31, 2004, the ESOP had no shares remaining to be allocated. Shares were released to provide employees with the company match in accordance with the terms of the TECO Energy Group Retirement Savings Plan and in lieu of dividends on allocated ESOP shares. The dividends received by the ESOP were used to pay debt service on the loan between TECO Energy and the ESOP.

For financial statement purposes, the unallocated shares of TECO Energy stock were reflected as a reduction of common equity, classified as unearned compensation. Dividends on all ESOP shares were recorded as a reduction of retained earnings, as are dividends on all TECO Energy common stock. The tax benefit related to dividends paid to the ESOP for allocated shares is a reduction of income tax expense and was $1.5 million, $1.6 million and $2.0 million for 2004, 2003 and 2002, respectively. The tax benefit related to dividends paid to the ESOP for unallocated shares is an increase in retained earnings and was $0.1 million, $0.4 million and $1.3 million in 2004, 2003 and 2002, respectively. All ESOP shares were considered outstanding for earnings per share computations.

## 10. Other Comprehensive Income

TECO Energy reported the following other comprehensive income (loss) (OCI) for the years ended Dec. 31, 2004, 2003 and 2002, related to changes in the fair value of cash flow hedges, foreign currency adjustments and adjustments to the minimum pension liability associated with the company's supplemental executive retirement plan:

| **Comprehensive Income (Loss)** *(millions)* | *Gross* | *Tax* | *Net* |
|---|---|---|---|
| **2004** | | | |
| Unrealized (loss) on cash flow hedges | **$ (14.6)** | **$ (4.9)** | **$ (9.7)** |
| Less: Loss reclassified to net income (1) | **22.8** | **8.3** | **14.5** |
| Gain on cash flow hedges | **8.2** | **3.4** | **4.8** |
| Foreign currency adjustments | **–** | **–** | **–** |
| Pension adjustments (2) | **9.5** | **2.3** | **7.2** |
| Total other comprehensive income | **$ 17.7** | **$ 5.7** | **$ 12.0** |
| **2003** | | | |
| Unrealized (loss) on cash flow hedges (1) | $ (31.8) | $ (10.6) | $ (21.2) |
| Less: Loss reclassified to net income (1) | 76.4 | 27.1 | 49.3 |
| Gain on cash flow hedges | 44.6 | 16.5 | 28.1 |
| Foreign currency adjustments | 1.2 | — | 1.2 |
| Pension adjustments(2) | (69.3) | (25.4) | (43.9) |
| Total other comprehensive (loss) | $ (23.5) | $ (8.9) | $ (14.6) |
| **2002** | | | |
| Unrealized (loss) on cash flow hedges (1) | $ (51.2) | $ (20.4) | $ (30.8) |
| Less: Loss reclassified to net income | 29.0 | 11.4 | 17.6 |
| (Loss) on cash flow hedges | (22.2) | (9.0) | (13.2) |
| Foreign currency adjustments | (1.2) | – | (1.2) |
| Pension adjustments(2) | (7.2) | (2.8) | (4.4) |
| Total other comprehensive (loss) | $ (30.6) | $ (11.8) | $ (18.8) |

(1) Amounts include interest rate swaps designated as cash flow hedges at TPGC, which was consolidated effective Apr. 1, 2003 as a result of the termination of the partnership. Prior to Apr. 1, 2003, only the company's proportionate share of its equity investee's comprehensive loss was included. See **Notes 20** and **21** for additional details regarding the OCI balances for cash flow hedges.
(2) See **Note 5** for additional details regarding pension adjustments.

| **Accumulated Other Comprehensive Income** *(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| Minimum pension liability adjustment (1) | **$ (44.3)** | $ (51.5) |
| Net unrealized gains (losses) from cash flow hedges (2) | **0.5** | (4.3) |
| Total accumulated other comprehensive income | **$ (43.8)** | $ (55.8) |

(1) Net of tax benefit of $27.9 million and $30.2 million, respectively, as of Dec. 31, 2004 and 2003, respectively.
(2) Net of tax benefit of $1.3 million and $4.7 million, respectively, as of Dec. 31, 2004 and 2003, respectively.

## 11. Earnings Per Share

For the years ended Dec. 31, 2004, 2003 and 2002, stock options for 10.6 million shares, 6.3 million shares and 4.5 million shares, respectively, were excluded from the computation of diluted earnings per share due to their antidilutive effect. Additionally, 1.9 million, 14.9 million and 14.9 million common shares issuable under the purchase contract associated with the mandatorily convertible equity units were also excluded from the computation of diluted earnings per share for the years ended Dec. 31, 2004, 2003 and 2002, respectively, due to their antidilutive effect.

| **Earnings Per Share** *(millions, except per share amounts) For the years ended Dec. 31,* | | | *2004* | *2003* | *2002* |
|---|---|---|---|---|---|
| **Numerator** | Net (loss) income from continuing operations, basic and diluted | | **$(404.4)** | $ 61.7 | $ 268.5 |
| | Discontinued operations, net of tax | | **(147.6)** | (966.8) | 61.6 |
| | Cumulative effect of a change in accounting principle, net | | **–** | (4.3) | – |
| | Net (loss) income, basic and diluted | | **$(552.0)** | $(909.4) | $ 330.1 |
| **Denominator** | Average number of shares outstanding - basic | | **192.6** | 179.9 | 153.2 |
| | Plus: Incremental shares for assumed conversions: | | | | |
| | Stock options at end of period and contingent performance shares | | **–** | 2.8 | 2.1 |
| | Less: Treasury shares which could be purchased | | **–** | (2.5) | (2.0) |
| | Average number of shares outstanding - diluted | | **192.6** | 180.2 | 153.3 |
| **Earnings per share from continuing operations** | | Basic | **$ (2.10)** | $ 0.34 | $ 1.75 |
| | | Diluted | **$ (2.10)** | $ 0.34 | $ 1.75 |
| **Earnings per share from discontinued operations, net** | | Basic | **$ (0.77)** | $ (5.37) | $ 0.40 |
| | | Diluted | **$ (0.77)** | $ (5.36) | $ 0.40 |
| **Earnings per share from cumulative effect of change in accounting principle, net** | | Basic | **$ –** | $ (0.02) | $ – |
| | | Diluted | **$ –** | $ (0.02) | $ – |
| **Earnings per share** | | Basic | **$ (2.87)** | $ (5.05) | $ 2.15 |
| | | Diluted | **$ (2.87)** | $ (5.04) | $ 2.15 |

## 12. Commitments and Contingencies

**Capital Investments**

TECO Energy has made certain commitments in connection with its continuing capital expenditure program. At Dec. 31, 2004, these estimated capital investments total approximately $1.7 billion for the years 2005 through 2009 and are summarized as follows:

**Forecasted Capital Investments**

| *As of Dec. 31, 2004* *(millions)* | *2005* | *2006* | *2007-2009* | *Total 2005-2009* |
|---|---|---|---|---|
| Tampa Electric | | | | |
| Transmission | $ 19.2 | $ 25.1 | $ 98.6 | $ 142.9 |
| Distribution | 75.4 | 78.4 | 235.8 | 389.6 |
| Generation | 56.1 | 57.5 | 190.8 | 304.4 |
| Other | 19.5 | 16.3 | 43.4 | 79.2 |
| Environmental | 44.3 | 69.3 | 285.6 | 399.2 |
| Tampa Electric Total | 214.5 | 246.6 | 854.2 | 1,315.3 |
| Peoples Gas | 40.0 | 40.0 | 120.0 | 200.0 |
| TECO Coal | 23.7 | 22.1 | 54.9 | 100.7 |
| TECO Transport | 19.6 | 20.2 | 59.4 | 99.2 |
| Other | 5.0 | 0.2 | 0.6 | 5.8 |
| Total | $302.8 | $ 329.1 | $1,089.1 | $1,721.0 |

For 2005, Tampa Electric's electric division expects to spend $215 million, consisting of $171 million to support system growth and generation reliability and $44 million for environmental compliance including $30 million for the addition of selective catalytic reduction (SCR) equipment at the Big Bend Power Station. At the end of 2004, Tampa Electric had outstanding commitments of about $105 million primarily for long-term capitalized maintenance agreements for its combustion turbines. Tampa Electric's total capital expenditures over the 2006 - 2009 period are projected to be $1,101 million, including $253 million for compliance with the Environmental Consent Decree for the SCR equipment and $101 million for other required environmental capital expenditures. The environmental compliance expenditures are eligible for recovery of depreciation and a return on investment through the Environmental Cost Recovery Clause (see **Note 1**).

Capital expenditures for PGS are expected to be about $40 million in 2005 and $160 million during the 2006 - 2009 period. Included in these amounts are approximately $25 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety.

TECO Coal and TECO Transport expect to invest $43 million in 2005 and $157 million during the 2006-2009 period. Included in these amounts is normal renewal and replacement capital, including coal mining equipment and capitalized maintenance on ocean-going vessels and inland river equipment.

The other unregulated companies expect to invest $5.0 million in 2005 and $0.8 million during 2006 through 2009, mainly for normal renewal and replacement capital.

**Legal Contingencies**

*TM Delmarva Power Arbitration*

TM Delmarva Power L.L.C. (TMDP), a TWG subsidiary, had reserved, but not yet paid, the full $49 million, representing the maximum payment obligation for an arbitration award plus accrued interest issued by the arbitration panel in a proceeding brought against TMDP by the non-equity member, NCP of Virginia, L.L.C. (NCP), in the Commonwealth Chesapeake Project (CCC). In August 2004, the company entered into an agreement with NCP and its owners under which TECO Energy and its subsidiary agreed to purchase NCP's interest in CCC for $30 million in cash plus shares of TECO Energy common stock having a value of $10 million, and NCP released all claims against the company and its subsidiaries. The funds and shares were released from escrow upon receipt of FERC approval on Sep. 30, 2004. The transaction to purchase the remaining interest in CCC from NCP therefore had a positive impact on pretax earnings of approximately $9 million in the third quarter of 2004. (See **Note 23** for discussion of a subsequent event involving CCC).

*Grupo Lawsuit*

In March 2001, TWG (under its former name of TECO Power Services Corporation) was served with a lawsuit filed in the Circuit Court for Hillsborough County by a Tampa-based firm named Grupo Interamerica, LLC. ("Grupo") in connection with a potential investment in a power project in Colombia in 1996. Grupo alleged, among other things, that TWG breached an oral contract with Grupo. On Aug. 3, 2004, the trial court granted TWG's motion for summary judgment, resulting in only one count remaining. On Oct. 18, 2004, TWG's motion for summary judgment on the remaining count was granted. The plaintiffs have appealed and the company expects that the appellate court would render a decision by the end of 2005.

On Aug. 30, 2004, a Colombian trade union, Sindicato de Trabajadores de la Electricidad de Colombia, which was to be the owner/lessor of the power plant if the transaction had been consummated, filed a demand for arbitration in Colombia pursuant to provisions of a confidentiality and exclusivity agreement (the "confidentiality agreement") between the trade union and a subsidiary of TWG, TPS International Power, Inc., alleging breach of contract and seeking damages of $48 million. TECO Energy, Inc. and TWG also were named, although those companies were not parties to the confidentiality agreement. This arbitration is being funded by Grupo pursuant to a contract under which Grupo would share in any recovery. The arbitration is in its preliminary stages, and, although the respondents have not been served, the parties' arbitrators have been selected by the parties.

*Other Issues*

A number of securities class action lawsuits were filed in August, September and October 2004 against the company and certain current and former officers by purchasers of TECO Energy securities. These suits, which were filed in the U.S. District Court for the Middle District of Florida, allege disclosure violations under the Securities Exchange Act of 1934. These actions were consolidated and remain in the initial pleading stage as of Dec. 31, 2004. On Feb. 1, 2005, the Court entered its order appointing the (i) "TECO Lead Plaintiff Group", comprised of NECA-IBEW Pension Fund (The Decatur Plan), Monroe County Employees Retirement System, John Marder and Charles Korpak, as the Lead Plaintiff for the Class and (ii) the law firm of Lerach Coughlin Stoia Geller Rudman & Robbins LLP as Lead Counsel. The plaintiffs have 60 days (or until Apr. 4, 2005) to file its consolidated complaint. The defendants will then have 60 days (or as late as Jun. 3, 2005) to file a motion to dismiss and supporting brief, and then the plaintiffs would have 60 days (or as late as Aug. 2, 2005) to file their opposition brief. The motion would then be before the Judge for a decision which could be made based on the papers or, after a hearing if scheduled at the Judge's discretion. The company intends to defend the litigation vigorously. In addition, in connection with the previously disclosed SEC informal inquiry resulting from a letter from the non-equity member in the CCC raising issues related to the arbitration proceeding involving that project, the SEC has requested additional information primarily relating to the allegations made in these securities class action lawsuits focusing on various merchant plant investments and related matters.

The company cannot predict the ultimate resolution of these matters, including the class action litigation and the Grupo-related proceedings, at this time, and there can be no assurance that any such matters will not have a material adverse impact on TECO Energy's financial condition or results of operations.

From time to time TECO Energy and its subsidiaries are involved in various other legal, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies in the ordinary course of its business. Where appropriate, accruals are made in accordance with FAS 5, *Accounting for Contingencies*, to provide for matters that are probable of resulting in an estimable, material loss. While the outcome of such proceedings is uncertain, management does not believe that the ultimate resolution of pending matters will have a material adverse effect on the company's results of operations or financial condition.

**Superfund and Former Manufactured Gas Plant Sites**

Tampa Electric Company, through its Tampa Electric and Peoples Gas divisions, is a potentially responsible party for certain superfund sites and, through its Peoples Gas division, for certain former manufactured gas plant sites. While the joint and several liability associated with these sites presents the potential for significant response costs, as of Dec. 31, 2004, Tampa Electric Company has estimated its ultimate financial liability to be approximately $17 million, and this amount has been accrued in the company's financial statements. The environmental remediation costs associated with these sites, which are expected to be paid over many years, are not expected to have a significant impact on customer prices.

The estimated amounts represent only the estimated portion of the cleanup costs attributable to Tampa Electric Company. The estimates to perform the work are based on actual estimates obtained from contractors, or Tampa Electric Company's experience with similar work adjusted for site specific conditions and agreements with the respective governmental agencies. The estimates are made in current dollars, are not discounted and do not assume any insurance recoveries.

Allocation of the responsibility for remediation costs among Tampa Electric Company and other potentially responsible parties (PRPs) is based on each party's relative ownership interest in or usage of a site. Accordingly, Tampa Electric Company's share of remediation costs varies with each site. In virtually all instances where other PRPs are involved, those PRPs are considered creditworthy.

Factors that could impact these estimates include the ability of other PRPs to pay their pro rata portion of the cleanup costs, additional testing and investigation which could expand the scope of the cleanup activities, additional liability that might arise from the cleanup activities themselves or changes in laws or regulations that could require additional remediation. These costs are recoverable through customer rates established in subsequent base rate proceedings.

**Long Term Commitments**

TECO Energy has commitments under long-term operating leases, primarily for building space, office equipment and heavy equipment, and marine assets at TECO Transport. On Dec. 30, 2002, TECO Transport completed a sale-leaseback transaction to be accounted for as an operating lease covering one ocean-going tug and barge, five river towboats and 49 river barges. On Dec. 21, 2001, TECO Transport sold three ocean-going barges and one ocean-going tug boat in a sale-leaseback transaction to be accounted for as an operating lease. Both lease terms are 12 years with early buyout options after 5 years.

Total rental expense for these operating leases, included in the Consolidated Statements of Income for the years ended Dec. 31, 2004, 2003 and 2002 was $32.3 million, $28.9 million and $26.0 million, respectively.

The following is a schedule of future minimum lease payments at Dec. 31, 2004 for all operating leases with noncancelable lease terms in excess of one year:

**Future Minimum Lease Payments For Operating Leases**

| *Year ended Dec. 31:* | *Amount (millions)* |
|---|---|
| 2005 | $ 25.2 |
| 2006 | 20.7 |
| 2007 | 17.2 |
| 2008 | 13.0 |
| 2009 | 12.6 |
| Later years | 68.3 |
| Total minimum lease payments | $ 157.0 |

In 1994, Tampa Electric bought out a long-term coal supply contract which would have expired in 2004 for a lump sum payment of $25.5 million. In February 1995, the FPSC authorized the recovery of this buy-out amount plus carrying costs through the Fuel and Purchased Power Cost Recovery Clause over the 10-year period beginning Apr. 1, 1995. In each of the years 2004, 2003 and 2002, $2.7 million of buy-out costs were amortized to expense.

**Guarantees and Letters of Credit**

On Jan. 1, 2003, TECO Energy adopted the prospective initial measurement provisions for certain types of guarantees, in accordance with FASB Interpretation No. (FIN) 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others (an interpretation of FASB Statements No. 5, 57 and 107 and rescission of FASB Interpretation No. 34).* Upon issuance or modification of a guarantee after Jan. 1, 2003, the company must determine if the obligation is subject to either or both of the following:

- Initial recognition and initial measurement of a liability; and/or
- Disclosure of specific details of the guarantee.

Generally, guarantees of the performance of a third party or guarantees that are based on an underlying (where such a guarantee is not a derivative subject to FAS 133) are likely to be subject to the recognition and measurement, as well as the disclosure provisions, of FIN 45. Such guarantees must initially be recorded at fair value, as determined in accordance with the interpretation.

Alternatively, guarantees between and on behalf of entities under common control or that are similar to product warranties are subject only to the disclosure provisions of the interpretation. The company must disclose information as to the term of the guarantee and the maximum potential amount of future gross payments (undiscounted) under the guarantee, even if the likelihood of a claim is remote.

A summary of the face amount or maximum theoretical obligation under TECO Energy's letters of credit and guarantees as of Dec. 31, 2004 are as follows:

**Letters of Credit and Guarantees**

| *(millions)* Letters of Credit and Guarantees for the Benefit of: | Maturing 2005 | 2006 | 2007-2009 | After 2009 | Total | Liabilities Recognized at Dec. 31, 2004 |
|---|---|---|---|---|---|---|
| **Tampa Electric** | | | | | | |
| Letters of credit | $ – | $ – | $ – | $ 2.4 | $ 2.4 | $ – |
| Guarantees: | | | | | | |
| Fuel purchase/energy management [1][2] | – | – | – | 20.0 | 20.0 | 0.1 |
| | – | – | – | 22.4 | 22.4 | 0.1 |
| **TECO Wholesale Generation-Merchant** | | | | | | |
| Guarantees: | | | | | | |
| Fuel purchase/energy management [2] | 174.9 | – | – | – | 174.9 | 5.0 |
| Construction/Investment related | 2.0 | – | – | – | 2.0 | – |
| | 176.9 | – | – | – | 176.9 | 5.0 |
| **TECO Transport** | | | | | | |
| Letters of credit | – | – | – | 2.4 | 2.4 | – |
| **TECO Coal** | | | | | | |
| Letters of credit | – | – | – | 20.0 | 20.0 | – |
| Guarantees: Other [2] | 10.0 | – | – | 1.4[1] | 11.4 | 2.2 |
| | 10.0 | – | – | 21.4 | 31.4 | 2.2 |
| **Other unregulated** | | | | | | |
| Letters of credit | – | 4.7 | – | – | 4.7 | – |
| Guarantees: | | | | | | |
| Debt related | – | – | – | 10.2 | 10.2 | 10.2 |
| Fuel purchase/energy management [1][2] | – | – | – | 8.7 | 8.7 | – |
| | – | 4.7 | – | 18.9 | 23.6 | 10.2 |
| Total | $186.9 | $ 4.7 | $ – | $ 65.1 | $ 256.7 | $17.5 |

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2009.
(2) The amounts shown are the maximum theoretical amount guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy under these agreements at Dec. 31, 2004. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.

**Financial Covenants**

A summary of TECO Energy's significant financial covenants as of Dec. 31, 2004 is as follows:

**TECO Energy Significant Financial Covenants**

| *(millions, unless otherwise indicated)* Instrument | *Financial Covenant* [1] | *Requirement/Restriction* | *Calculation at Dec. 31, 2004* |
|---|---|---|---|
| **Tampa Electric** | | | |
| PGS senior notes | EBIT/interest [2] | Minimum of 2.0 times | 3.5 times |
| | Restricted payments | Shareholder equity at least $500 | $1,662 |
| | Funded debt/capital | Cannot exceed 65% | 49.5% |
| | Sale of assets | Less than 20% of total assets | –% |
| Credit facilities [3] | Debt/capital | Cannot exceed 60% | 49.7% |
| | EBITDA/interest [2] | Minimum of 2.0 times | 5.5 times |
| 6.25% senior notes | Debt/capital | Cannot exceed 60% | 49.7% |
| | Limit on liens | Cannot exceed $787 | $287 liens outstanding |
| **TECO Energy** | | | |
| Credit facility [3] | Debt/EBITDA [2] | Cannot exceed 5.25 times | 4.5 times |
| | EBITDA/interest [2] | Minimum of 2.25 times | 2.7 times |
| | Limit on additional indebtedness | Cannot exceed $100 million | $ – |
| $380 million note indenture | Limit on restricted payments [4] | Cumulative operating cash flow in excess of 1.7 times interest | $258 unrestricted |
| | Limit on liens | Cannot exceed 5% of tangible assets | $236 unrestricted |
| | Limit on indebtedness | Interest coverage at least 2.0 times | 2.5 times |
| $300 million note indenture | Limit on liens | Cannot exceed 5% of tangible assets | $236 unrestricted |
| Union and Gila River project guarantees [5] | Debit/capital | Cannot exceed 65% | 70.0% [6] |
| | EBITDA/interest [2] | Minimum of 3.0 times | 1.9 times [6] |
| **TECO Diversified** | | | |
| Coal supply agreement guarantee | Dividend restriction | Net worth not less than $418 (40% of tangible net assets) | $564 |

(1) As defined in each applicable instrument.
(2) EBIT generally represents earnings before interest and taxes. EBITDA generally represents EBIT before depreciation and amortization. However, in each circumstance, the term is subject to the definition prescribed under the relevant agreements.
(3) See description of credit facilities in **Note 6**.
(4) The limitation on restricted payments restricts the company from paying dividends or making distributions or certain investments unless there is sufficient cumulative operating cash flow, as defined, in excess of 1.7 times interest to make such distribution or investment. The operating cash flow and restricted payments are calculated on a cumulative basis since the issuance of the 10.5% Notes in the fourth quarter of 2002. This calculation, at Dec. 31, 2004, reflects the amount accumulated since the issuance of the notes available for future restricted payments.
(5) See **TPGC Guarantees** below.
(6) The Construction Undertakings permit TECO Energy to terminate its obligation is thereunder, including the requirement to comply with the covenants, by providing a Substitute Guarantor reasonably satisfactory to the lending group. On Sep. 22, 2003, TECO Energy tendered a Substitute Guarantor, which it believes satisfied the requirements of the Construction Undertakings. The lending group declined to accept this tender as being satisfactory. TECO Energy has the right to assert that the Construction Undertakings are terminated in the event that the lending group seeks to exercise its remedies based on a violation of the EBITDA-to-interest coverage ratio and the debt-to-capital covenants.

**TPGC Guarantees**

The TECO Energy guarantees of the equity contribution agreements of TPGC and the Construction Undertaking contain debt/capital and EBITDA/interest financial covenants. The company was not in compliance with the EBITDA/interest covenant at any quarterly measurement period in 2004 and was not in compliance with the debt/capital covenant at Dec. 31, 2004. Non-compliance constitutes a default under the non-recourse bank credit agreements of the Union and Gila River project companies (TPGC), but does not create a cross-default under any TECO Energy agreement.

In December 2003, the Union and Gila River project companies were unable to make interest payments on the non-recourse debt and payments under interest rate swap agreements due Dec. 31, 2003 when the project lenders declined to fund the debt service reserve. Subsequently, the project companies, the project lenders and TECO Energy entered into a series of discussions and agreements and during 2004 the company announced that an agreement had been reached with the steering committee of the project lenders on all material terms and forms of definitive agreements for the sale and transfer to the lenders of ownership of these plants. See **Note 21** for further discussion on this agreement and **Note 23** for details of a related subsequent event.

## *13. Related Parties*

In October 2003, Tampa Electric signed a five-year contract renewal with an affiliate company, TECO Transport, for integrated waterborne fuel transportation services effective Jan. 1, 2004. The contract calls for inland river and ocean transportation along with river terminal storage and blending services for up to 5.5 million tons of coal annually through 2008. In September 2004, the FPSC voted to disallow approximately $14 to $16 million (pretax) of the costs that Tampa Electric can recover from its customers for water transportation services. This impact has been fully recognized by Tampa Electric for 2004. The decision allows, but does not require, Tampa Electric to rebid the water transportation and terminal service contract. Tampa Electric filed its objection to the disallowance on Oct. 27, 2004, and a decision on this matter is expected in the first quarter of 2005. See **Note 23** for a subsequent event.

In February 2002, Tampa Electric and TECO-Panda Generating Company II (TPGC II) entered into an assignment and assumption agreement under which Tampa Electric obtained TPGC II's rights and interests to four combustion turbines being purchased from General Electric, and assumed the corresponding liabilities and obligations for such equipment. In accordance with the terms of the assignment and assumption agreement, Tampa Electric paid $62.5 million to TPGC II as reimbursement for amounts already paid to General Electric by TPGC II for such equipment. No gain or loss was incurred on the transfer. In the first quarter of 2003, Tampa

Electric recorded a $48.9 million after-tax charge related to the cancellation of these turbine purchase commitments (see **Note 18**).

As of Dec. 31, 2003, a note receivable of $8.1 million due from EEGSA, an unconsolidated affiliate, bearing a current effective interest rate of 6.14%, was recorded on the balance sheet. In 2004, this note was repaid in full.

On Jan. 3, 2003, the $137.0 million loan receivable from PLC, a wholly-owned subsidiary of Panda Energy, converted to a 50% ownership interest in PLC, leading to a joint venture with Panda Energy. This joint venture held a 50% ownership interest in Texas Independent Energy, L.P. (TIE). The TIE partnership owns and operates the Odessa and Guadalupe power stations in Texas. In September 2003, TWG completed foreclosure proceedings against Panda Energy for their ownership interest in PLC as a result of Panda's default under a $23.0 million note receivable. Consequently, in 2003, PLC was fully consolidated and the $23.0 million note receivable was converted to an equity interest. The investment in PLC was sold in 2004. See also **Note 16** for additional information regarding PLC.

The company and its subsidiaries had certain transactions, in the ordinary course of business, with entities in which directors of the company had interests. The company paid legal fees of $1.4 million, $1.2 million and $1.1 million for the years ended Dec. 31, 2004, 2003 and 2002, respectively, to Ausley McMullen, of which Mr. Ausley (a director of TECO Energy) is an employee. Other transactions were not material for the years ended Dec. 31, 2004, 2003 and 2002. No material balances were payable as of Dec. 31, 2004 or 2003.

## *14. Segment Information*

TECO Energy is an electric and gas utility holding company with significant diversified activities. Segments are determined based on how management evaluates, measures and makes decisions with respect to the operations of the entity. The management of TECO Energy reports segments based on each subsidiary's contribution of revenues, net income and total assets, as required by FAS 131, *Disclosures about Segments of an Enterprise and Related Information*. All significant intercompany transactions are eliminated in the consolidated financial statements of TECO Energy, but are included in determining reportable segments.

As more fully described in **Note 1**, in 2003, the company revised internal reporting information for the purpose of evaluating, measuring and making decisions with respect to the components which previously comprised the TECO Power Services operating segment. The revised operating segment, TWG-Mechant, is comprised of all merchant operations. The non-merchant components are now included in Other Unregulated operations.

The information presented in the following table excludes all discontinued operations. See **Note 21** for additional details of the components of discontinued operations.

**Segment Information** [1]

| (millions) | | Tampa Electric | Peoples Gas | TECO Coal | TECO Transport | Other Unregulated | TWG Merchant | Eliminations & Other | Total TECO Energy |
|---|---|---|---|---|---|---|---|---|---|
| **2004** | Revenues - outsiders | $ 1,683.8 | $ 417.2 | $ 327.6 | $ 173.4 | $ 29.0 | $ 37.3 | $ 0.8 | $ 2,669.1 |
| | Sales to affiliates | 3.6 | – | – | 76.2 | 7.6 | – | (87.4) | – |
| | Total revenues | $ 1,687.4 | $ 417.2 | $ 327.6 | $ 249.6 | $ 36.6 | $ 37.3 | $ (86.6) | $ 2,669.1 |
| | Depreciation | 180.9 | 34.1 | 36.3 | 21.9 | 1.6 | 7.4 | 0.1 | 282.3 |
| | Restructuring costs [2] | – | 0.7 | – | – | – | 0.5 | – | 1.2 |
| | Total interest charges [3] | 95.8 | 15.2 | 11.2 | 4.7 | 15.8 | 49.4 | 129.5 | 321.6 |
| | Internally allocated interest [3] | – | – | 11.1 | (1.0) | 15.3 | 50.7 | (77.8) | (1.7) |
| | (Benefit) provision for taxes | 83.9 | 17.3 | 22.8 | 4.6 | 16.2 | (334.0) | (75.9) | (265.1) |
| | Net (loss) income from continuing operations [3] | $ 146.0 | $ 27.7 | $ 61.3 | $ 10.2 | $ 12.1 [5] | $(583.0) [4] | $ (78.7) | $ (404.4) |
| | Goodwill, net | – | – | – | – | 59.4 | – | – | 59.4 |
| | Investment in unconsolidated affiliates | – | – | – | 3.3 | 239.5 | – | 20.2 | 263.0 |
| | Other non-current investments | – | – | – | – | 8.0 | – | – | 8.0 |
| | Total assets | 4,167.3 | 671.1 | 413.9 | 315.4 | 500.8 | 2,736.8 | 671.2 | 9,476.5 |
| | Capital expenditures | 181.2 | 38.7 | 22.9 | 20.2 | 0.5 | 0.2 | – | 263.7 |
| **2003** | Revenues - outsiders | $ 1,582.7 | $ 408.4 | $ 296.3 | $ 162.2 | $ 115.5 | $ 32.8 | $ 0.4 | $ 2,598.3 |
| | Sales to affiliates | 3.4 | – | – | 98.4 | 58.0 | – | (159.8) | – |
| | Total revenues | $ 1,586.1 | $ 408.4 | $ 296.3 | $ 260.6 | $ 173.5 | $ 32.8 | $ (159.4) | $ 2,598.3 |
| | Depreciation | 210.3 | 32.7 | 34.2 | 20.6 | 15.3 | 5.9 | 0.1 | 319.1 |
| | Restructuring costs [2] | 9.9 | 4.1 | – | 1.7 | 5.9 | 0.4 | 2.6 | 24.6 |
| | Total interest charges [3] | 85.0 | 15.6 | 11.0 | 4.9 | 25.4 | 57.2 | 118.9 | 318.0 |
| | Internally allocated interest [3] | – | – | 11.0 | (2.0) | 15.3 | 67.8 | (95.8) | (3.7) |
| | (Benefit) provision for taxes | 48.3 | 15.7 | (64.4) | 9.7 | 6.6 | (60.1) [7] | (47.3) | (91.5) |
| | Net income (loss) from continuing operations [3] | $ 98.9 [6] | $ 24.5 | $ 77.1 | $ 15.3 | $ 23.2 [5] | $ (99.8) [4] | $ (77.5) | $ 61.7 |
| | Goodwill, net | – | – | – | – | 71.2 | – | – | 71.2 |
| | Investment in unconsolidated affiliates | – | – | – | – | 184.6 | 158.9 | – | 343.5 |
| | Other non-current investments | – | – | – | – | 16.5 | – | – | 16.5 |
| | Total assets | 4,178.6 | 651.5 | 340.8 | 315.8 | 851.2 | 3,504.4 | 620.0 | 10,462.3 |
| | Capital expenditures | 289.1 | 42.6 | 20.6 | 19.6 | 21.2 | 6.0 | 0.1 | 399.2 |
| **2002** | Revenues - outsiders | $ 1,548.9 | $ 318.1 | $ 316.4 | $ 143.9 | $ 155.2 | $ 28.0 | $ – | $ 2,510.5 |
| | Sales to affiliates | 34.3 | – | 0.7 | 110.7 | 60.6 | – | (206.3) | – |
| | Total revenues | $ 1,583.2 | $ 318.1 | $ 317.1 | $ 254.6 | $ 215.8 | $ 28.0 | $ (206.3) | $ 2,510.5 |
| | Depreciation | 189.8 | 30.5 | 31.4 | 22.3 | 16.4 | 5.6 | 0.1 | 296.1 |
| | Restructuring costs [2] | 16.6 | – | – | – | 1.2 | – | – | 17.8 |
| | Total interest charges [3] | 51.5 | 14.8 | 8.2 | 6.3 | 34.9 | 24.2 | 29.4 | 169.3 |
| | Internally allocated interest [3] | – | – | 8.1 | (1.7) | 17.1 | 87.5 | (115.7) | (4.7) |
| | (Benefit) provision for taxes | 86.1 | 14.7 | (130.2) | 10.8 | 0.5 | (9.4) [7] | (29.4) | (56.9) |
| | Net income (loss) from continuing operations [3] | $ 171.8 | $ 24.2 | $ 76.4 | $ 21.0 | $ 27.0 | $ (15.7) | $ (36.2) | $ 268.5 |
| | Goodwill, net | – | – | – | – | 98.6 | 95.1 | – | 193.7 |
| | Investment in unconsolidated affiliates | – | – | – | – | 187.4 | (38.2) | – | 149.2 |
| | Other non-current investments | – | – | – | – | 49.2 | 795.8 | 0.3 | 845.3 |
| | Total assets | 4,119.4 | 629.9 | 283.5 | 355.1 | 1,072.4 | 2,113.9 | 504.2 | 9,078.4 |
| | Capital expenditures | 632.2 | 53.5 | 48.2 | 25.2 | 77.0 | 222.7 | – | 1,058.8 |

(1) From continuing operations. All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for: Frontera Generation Limited Partnership, and the Union and Gila River projects (formerly part of TWG); and TECO Coalbed Methane, Prior Energy, BGA, BCH Mechanical and AGC (formerly part of Other Unregulated). See **Note 21**.

(2) See **Note 19** for a discussion of restructuring charges in 2004, 2003 and 2002.

(3) *Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2004, 2003 and 2002 were at pre-*tax rates of 8%, 8% and 7%, respectively, based on the average investment in each subsidiary. Internally allocated interest charges are a component of total interest charges.

(4) Net income for 2004 includes after-tax charges of $442.8 million ($690.8 million pretax) for asset and intangible impairments for the Dell, McAdams and CCC merchant assets (see **Note 18**), and a $99.0 million after-tax charge ($152.3 million pretax) to write-off its investment in TIE (see **Note 16**). Net income for 2003 includes a $26.7 million after-tax charge ($42.0 million pretax) related to a contingent arbitration proceeding (see the **Legal Contingencies** section of **Note 12**) and, a $16.4 million after-tax charge ($26.3 million pretax) for goodwill impairment (see **Note 17**).

(5) Net income for 2004 includes a $12.8 million after-tax asset impairment charge ($21.1 million pretax) related to certain steam turbines (see **Note 18**), $24.1 million in after-tax charges associated with debt extinguishment and income taxes due to repatriation of cash following refinancing for the San José Power Station in Guatemala and a $12.0 million after-tax gain ($19.7 million pretax) on the sale of its interest in the propane business (see **Note 16**). Net income for 2003 includes $37.5 million after-tax asset and intangible impairment charges ($59.9 million pretax) primarily related to the steam turbines and *project cancellation costs (see* **Note 18***) and $34.6 million of after-tax gains ($56.3 million pretax) on the sale of HPP (see* **Note 16***).*

(6) Net income for 2003 includes a $48.9 million after-tax ($79.6 million pretax) asset impairment charge related to turbine purchase cancellations (see **Note 18**).

(7) Taxes have been allocated, for segment reporting purposes, to TWG based on the weighted-average tax rates of the TWG components.

Tampa Electric Company provides retail electric utility services to more than 625,000 customers in West Central Florida. Its Peoples Gas System division is engaged in the purchase and distribution of natural gas for more than 314,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

TECO Transport, through its wholly-owned subsidiaries, transports, stores and transfers coal and other dry bulk commodities for third parties and Tampa Electric. TECO Transport's subsidiaries operate on the Mississippi, Ohio and Illinois rivers, in the Gulf of Mexico and worldwide.

TECO Coal, through its wholly owned subsidiaries, owns mineral rights and owns or operates surface and underground mines and coal processing and loading facilities in Kentucky, Tennessee and Virginia. TECO Coal acquired and began operating two synfuel facilities in 2000, whose production qualifies for the non-conventional fuels tax credit. In 2003 these synfuel operations were transferred into a newly formed LLC for the purpose of continuing growth in the production and sale of synthetic fuel. In April 2003, TECO Coal sold 49.5% interest in this entity and an additional 40.5% in 2004 (see **Note 16**).

TWG-Mechant has subsidiaries that have interests in independent power projects in Virginia, Arkansas, and Mississippi.

TECO Energy's other unregulated businesses are primarily engaged in owning and operating independent power projects with long-term contracts in Guatemala, and, until the date of the sale of the Hamakua Power Station, Hawaii (see **Note 16**).

**Foreign Operations**

Other Unregulated includes independent power operations and investments in Guatemala. TECO Energy, through its equity investments, has a 96% ownership interest and operates the 78-megawatt Alborada power station that supplies energy to EEGSA, an electric utility in Guatemala, under a U.S. dollar-denominated power sales agreement. TECO Energy, through its equity investments, also has a 100% ownership interest in the 120-megawatt San José power station and in transmission facilities in Guatemala. The plant provides capacity under a U.S. dollar-denominated power sales agreement to EEGSA. Prior to 2004 and the adoption of FIN 46R, the subsidiaries that hold interests in the San José and Alborada power stations in Guatemala were consolidated entities. As of Jan. 1, 2004, in accordance with the interpretation and application of the consolidation guidance established in FIN 46R to long-term power purchase agreements, TECO Energy can no longer consolidate these project companies and they are considered equity investments (see **Notes 1** and **2** for additional details).

TECO Energy, through a wholly-owned subsidiary, owns a 30% interest in a three member consortium that also includes Iberdrola, an electric utility in Spain, and Electricidad de Portugal, an electric utility in Portugal. The consortium, called Distribuidora Eléctrica Centroamericana Dos ("DECA II") owns an 80.9% interest in both EEGSA and Inversiones Eléctricas Centroamericanas, S.A. ("INVELCA"), the holding company for Guatemalan-based electric transmission ("TRELEC"), services ("Energica") and unregulated distribution ("Comegsa") companies, and a 55% interest in Novega.com, a telecommunications and data transmission carrier.

Total assets at Dec. 31, 2004, 2003 and 2002 included $327.2 million, $445.8 million and $415.9 million, respectively, related to these Guatemalan operations and investments. Revenues included $6.7 million, $82.7 million and $85.1 million for the years ended Dec. 31, 2004, 2003 and 2002, respectively, and income from equity investments included $45.2 million, $8.8 million and $3.3 million for the same periods from these Guatemalan operations and investments.

## 15. Asset Retirement Obligations

On Jan. 1, 2003, TECO Energy adopted FAS 143, *Accounting for Asset Retirement Obligations*. The company recognized liabilities for retirement obligations associated with certain long-lived assets, in accordance with the relevant accounting guidance. An asset retirement obligation (ARO) for a long-lived asset is recognized at fair value at inception of the obligation if there is a legal obligation under an existing or enacted law or statute, a written or oral contract, or by legal construction under the doctrine of promissory estoppel. Retirement obligations are recognized only if the legal obligation exists in connection with or as a result of the permanent retirement, abandonment or sale of a long-lived asset.

When the liability is initially recorded, the carrying amount of the related long-lived asset is correspondingly increased. Over time, the liability is accreted to its future value. The corresponding amount capitalized at inception is depreciated over the remaining useful life of the asset. The liability must be revalued each period based on current market prices.

TECO Energy has recognized asset retirement obligations for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations. Prior to the adoption of FAS 143, TECO Coal accrued reclamation costs for such activities. For TECO Coal, the adoption of FAS 143 modified the valuation and accrual methods used to estimate the fair value of asset retirement obligations.

As a result of the adoption of FAS 143, in 2003 TECO Energy recorded an increase to net property, plant and equipment of $7.8 million (net of accumulated depreciation of $6.6 million) and an increase to asset retirement obligations of $22.1 million, partially offset by previously recognized accrued reclamation obligations associated with coal mining activities of $12.3 million. A pretax charge of $1.8 million, net of a $0.2 million offset due to a regulatory asset at Tampa Electric, ($1.1 million after tax) was recognized as a change in accounting principle.

For the years ended Dec. 31, 2004 and Dec. 31, 2003, TECO Energy recognized $2.0 million and $1.2 million of accretion expense, respectively, associated with asset retirement obligations. During 2004, no significant additional ARO obligations were incurred, and no significant revisions to estimated cash flows used in determining the recognized asset retirement obligations were necessary. FAS 143 was not effective for the year ended Dec. 31, 2002.

As regulated utilities, Tampa Electric and PGS must file depreciation and dismantlement studies periodically and receive approval from the FPSC before implementing new depreciation rates. Included in approved depreciation rates is either an implicit net salvage factor or a cost of removal factor, expressed as a percentage. The net salvage factor is principally comprised of two components—a salvage factor and a cost of removal or dismantlement factor. The company uses current cost of removal or dismantlement factors as part of the estimation method to approximate the amount of cost of removal in accumulated depreciation.

Upon adoption of FAS 143 at Jan. 1, 2003, the estimated accumulated cost of removal and dismantlement included in net accumulated depreciation as of Dec. 31, 2003 of $462.2 million was reclassified to a regulatory liability (see also **Note 3**). For Tampa Electric and PGS, the original cost of utility plant retired or otherwise disposed of and the cost of removal, or dismantlement, less salvage value is charged to accumulated depreciation and the accumulated cost of removal reserve reported as a regulatory liability, respectively.

## *16. Mergers, Acquisitions and Dispositions*

**PLC Development/TIE**

At Dec. 31, 2002, TWG had a loan receivable of $137 million from PLC, a subsidiary of Panda Energy International. On Jan. 3, 2003, this loan was converted to a partnership interest in PLC. See **Notes 1** and **13** for additional details regarding the conversion of this loan to an equity interest in PLC. Furthermore, in September 2003, the company consummated the foreclosure on Panda Energy's interest in PLC for a default under a $23 million note receivable leading to TWG's 100% ownership in PLC which owns 50% of TIE (see **Notes 1, 13** and **20**). As of Sep. 30, 2003, TWG consolidated PLC, resulting in a net increase in investment in unconsolidated affiliates of approximately $18 million. On Aug. 30, 2004, a TWG-Mechant subsidiary completed the sale of its 50% indirect interest in TIE to PSEG Americas Inc., for $0.5 million. The company recorded a $152.3 million pretax impairment ($99.0 million after tax) to write off the value of the investment as a result of the sale.

Summary financial information for TIE is included in the table below.

| *(millions)* | *2004*(1) | *2003* |
|---|---|---|
| Revenues | **$ 319.7** | $ 453.1 |
| Operating income | **4.8** | 25.5 |
| Net (loss) available for allocation to partners | **$ (18.3)** | $ (14.4) |
| | | |
| Current assets | **$ –** | $ 57.9 |
| Non-current assets | **–** | 802.7 |
| Current liabilities | **–** | 83.5 |
| Non-current liabilities | **$ –** | $ 500.1 |

(1) 2004 only reflects results through Jul. 31, 2004, the effective date of the sale. The amounts reflected for July 2004 represent estimates based on information received from the management of TIE

**Frontera**

On Dec. 22, 2004, a subsidiary of TWG Mechant, Inc. completed the sale of its interests in Frontera Generation Limited Partnership (Frontera), the owner of the Frontera Power Station in Texas, to a subsidiary of Centrica plc for $133.7 million, consisting of $128.5 million of cash and assumption of $5.2 million of liabilities. TECO Energy has the opportunity to receive an Annual Earnout Payment if Frontera is the successful bidder and enters into a Reliability Must Run Contract with the Electric Reliability Council of Texas (ERCOT). Both TECO Energy and Centrica plc have guaranteed the payment obligations of their respective direct or indirect subsidiaries under the Purchase Agreement, with Centrica's obligation limited to 10% of the Adjusted Purchase Price (as defined in the Purchase Agreement). As a result of the sale, a pretax loss of $42.1 million ($27.0 million after tax) was recorded. The sale is subject to certain ordinary and customary post-closing adjustments to working capital items. These adjustments are not expected to be material. See **Note 21 – Other transactions** for additional details related to this transaction.

**Commonwealth Chesapeake**

In August 2004, the company entered into an agreement with NCP of Virginia, LLC (NCP), the non-equity member in Commonwealth Chesapeake Company (CCC), under which TECO Energy and a subsidiary agreed to purchase NCP's interest in CCC for $30 million in cash plus shares of TECO Energy common stock having a value of $10 million, and NCP released all claims against the company and its subsidiaries. The funds and shares were released from escrow upon receipt of FERC approval on Sept. 30, 2004 (see **Note 12** for additional details of this transaction and **Note 23** for discussion of a subsequent event involving CCC).

**TECO Propane Ventures**

In the first quarter of 2004, US Propane, LLC sold a majority of its assets, consisting of direct and indirect equity investments in Heritage Propane Partners, L.P., and the remaining indirect investment was sold in the second quarter of 2004. The sales resulted in cash proceeds of $53 million and after-tax gains totaling $12.0 million.

**Hamakua Power Station**

On Jul. 15, 2004, TECO Wholesale Generation's 50% indirect interest in the Hamakua Power Station in Hawaii was sold to an affiliate of Black River Energy, an affiliate of Energy Investors Funds' US Power Fund, L.P. Via its ownership of Black River Energy, which already owns 50% of the plant, Energy Investors Funds is now the sole owner of Hamakua. Cash proceeds from the sale were approximately $12 million, and resulted in an immaterial gain. As a result of the transaction, TECO Energy was also relieved of certain financial guarantees related to the facility.

**Prior Energy**

Effective Feb. 1, 2004, a subsidiary of TECO Energy completed the sale of Prior Energy for net proceeds of approximately $30 million. This sale did not result in a material gain or loss to the company. See the **Other transactions** section of **Note 21** for additional details relating to this disposition.

**BGA**

Effective Jan. 1, 2004, the company completed the sale of TECO BGA, Inc. (formerly a component of TECO Energy Services) to an entity owned by an employee group for a loss on disposal of $12.2 million ($7.5 million after tax). This loss was recorded as part of the asset impairment charge reported in the income statement for the year ended Dec. 31, 2003.

**Synthetic Fuel Facilities**

Effective Apr. 1, 2003, TECO Coal sold a 49.5% interest in its synthetic fuel production facilities located at its operations in eastern Kentucky. No significant gain or loss was recognized at the time of the sale. The company, through its various affiliates, will provide feedstock supply, and operating, sales and management services to the buyer through 2007, the current expiry date for the related Section 29 credit for which the production qualifies. Because the transaction was structured on a deferred payment basis typical of similar transactions in the industry, TECO Coal received no significant cash at the time of sale. The sale required receipt of a positive response to a Private Letter Ruling (PLR) request, and the proceeds from this transaction were held in escrow pending resolution of this contingency. On Oct. 31, 2003, TECO Coal received a PLR from the IRS that resolved any uncertainty related to the previous sale of the 49.5% interest in its synthetic fuel facilities; triggered the release of certain cash escrows related to this sale; and confirmed that synthetic fuel produced by TECO Coal is eligible for Section 29 credits and that its testing procedures are in compliance with the requirements of the IRS. On Nov. 5, 2003, $58.9 million of restricted cash that had been held in escrow was released following receipt of the PLR. In June 2004, TECO Coal sold an additional 40.5% of its membership interest in the synthetic fuel facilities under similar terms as the first transaction. In addition to retaining a 10% membership interest in the facilities, the TECO Coal subsidiary will continue to supply the feedstock and operate the facilities.

**TECO Coalbed Methane**

TECO Coalbed Methane, a subsidiary of TECO Energy, produced natural gas from coal seams in Alabama's Black Warrior Basin. In September 2002, the company announced its intent to sell the TECO Coalbed Methane gas assets. On Dec. 20, 2002, substantially all of TECO Coalbed Methane's assets in Alabama were sold to the Municipal Gas Authority of Georgia. Proceeds from the sale were $140 million, $42 million paid in cash at closing, and a $98 million note receivable which was paid in January 2003. Net income for the year ended Dec. 31, 2003 included a $23.5 million after-tax gain for the final cash installment from the sale of these assets. TECO Coalbed Methane's results are included in discontinued operations for all periods presented (see **Note 21**).

**Hardee Power Partners**

In 2003, Hardee Power Partners, Ltd.. (HPP), which holds a 370-MW gas-fired generation facility located in central Florida, was sold to an affiliate of Invenergy LLC and GTCR Golden Rauner LLC. Under the terms of the sale, subsidiaries of the company would continue to provide service to HPP under the existing operation and maintenance agreement. Under the terms of the agreement, these services ceased in September 2004. Additionally, Tampa Electric's long-term power purchase obligation to receive electricity from HPP remains in effect with no changes as a result of the transaction (see **Note 1**). The sale proceeds of approximately $107 million exceeded the net book value of $51.5 million (including assets of $149.1 million and liabilities of $97.6 million) resulting in a pretax gain of $56.3 million.

Due to the anticipated power purchases by Tampa Electric from HPP under the pre-existing long-term power purchase agreement (see the **Purchased Power** section of **Note 1**) resulting in cash outflows, the results from operations are precluded from being presented as discontinued operations.

## *17. Goodwill and Other Intangible Assets*

Effective Jan. 1, 2002, TECO Energy and its subsidiaries adopted FAS 141, *Business Combinations*, and FAS 142, *Goodwill and Other Intangible Assets*. FAS 141 requires all business combinations initiated after Jun. 30, 2001 to be accounted for using the purchase method of accounting. With the adoption of FAS 142, goodwill is no longer subject to amortization. Rather, goodwill and intangible assets, with an indefinite life, are subject to an annual assessment for impairment by applying a fair-value-based test. Intangible assets with a measurable useful life are required to be amortized.

As required under FAS 142, TECO Energy reviews recorded goodwill and intangible assets at least annually for each reporting unit. Reporting units are generally determined as one level below the operating segment level; reporting units with similar characteristics are grouped for the purpose of determining the impairment, if any, of goodwill and other intangible assets. The fair value for the reporting units evaluated is generally determined using discounted cash flows appropriate for the business model of each significant group of assets within each reporting unit. The models incorporate assumptions relating to future results of operations that are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Management periodically reviews and adjusts the assumptions, as necessary, to reflect current market conditions and observable activity. If a sale is expected in the near term or a similar transaction can be readily observed in the marketplace, then this information is used by management to estimate the fair value of the reporting unit.

In December 2004, the company recognized an $11.8 million pretax charge ($8.4 million after tax) to write off the value of the remaining goodwill associated with BCH Mechanical. In 2003, the company recorded pretax goodwill impairments of $17.7 million ($10.9 million after tax) and $1.7 million ($1.1 million after tax), respectively, for BCH Mechanical and TECO BGA. These charges are reflected in discontinued operations. See **Notes 21** and **23** for additional details.

In December 2004, as a result of its annual impairment assessment, the company recognized a pretax impairment charge of $4.8 million ($3.1 million after tax) to write off the value of an intangible asset associated with the acquisition of the Commonwealth Chesapeake power station (See **Note 18** for additional details). In 2003, the company also recognized pretax impairment charges of $6.6 million ($4.1 million after tax) to write-off technology licenses at TWG. Included in discontinued operations in 2003 is a pretax impairment charge of $1.5 million ($0.8 million after tax) to write off a long-term customer arrangement at BGA. For the years ended Dec. 31, 2004, 2003 and 2002, the company recognized amortization expense of $0.2 million, $4.7 million and $23.1 million, respectively.

Further, the company recognized a pretax impairment charge in June 2003 of $95.2 million ($61.2 million after tax) to write off all of the goodwill previously recorded at TWG merchant based on the implied fair value of its goodwill, in accordance with FAS 142. This goodwill arose from the previous acquisitions of the Commonwealth Chesapeake power station in Virginia and the Frontera power station in Texas. Of this amount, the impairment of Frontera goodwill of $68.9 million ($44.8 million after tax) is reflected in discontinued operations as a result of the company's sale of its interest in Frontera in December 2004 (See **Note 16** for additional details).

The company has $59.4 million of goodwill remaining on its balance sheet as of Dec. 31, 2004, which is reflected in the other unregulated segment. Additionally, as of Dec. 31, 2004, the company has no more intangible assets.

## *18. Asset Impairments*

Following major investments in merchant power, during 2001 and 2002 conditions in merchant energy markets changed dramatically, reducing prospects for profitability and leading to cessation of new merchant development activities in 2003. During 2003, the company announced that it would re-focus on its regulated utilities and its profitable unregulated businesses, and reduce its exposure to the merchant power sector. This led to the decision in 2003 to exit the Union and Gila River power stations (see **Note 21** for additional details). During 2004, wholesale power prices remained weak and prospects for price recovery for the next several years remained poor. While management monitored these events throughout 2004, there were no specific triggering events prior to the fourth quarter that warranted a SFAS 142 or 144 impairment analysis. In the fourth quarter of 2004, management conducted a review of prospects for long-term price recovery as well as opportunities for sales of the assets. This review led to the sale of the company's investment in the Frontera power station in Dec. 2004 (see **Note 16**). Also as a result of this review, management determined as of Dec. 31, 2004 a lower probability that the remaining merchant investments would be held for the long term, resulting in impairments to the Dell, McAdams, and Commonwealth Chesapeake power stations described below.

In December 2004, a pretax impairment charge of $609.5 million ($390.7 million after tax) was recognized related to the company's investments in the Dell and McAdams power stations. Under a probability analysis weighted toward short-term recovery, the investments failed the recoverability test of FAS 144. As a result, the assets were written down to fair market value based on a probability weighting of potential sales of the assets and salvage value, which represented the best estimate of fair market value.

In December 2004, the company recognized a pretax impairment charge of $81.3 million ($52.1 million after tax) related to its investment in the Commonwealth Chesapeake power station. Under a probability analysis weighted toward short-term recovery, the investments failed the recoverability test of FAS 144. As a result, the assets were written down to fair market value based on a probability weighting of potential sales of the assets, which represented the best estimate of fair market value. Of the $81.3 million charge, $4.8 million ($3.0 million after tax) was recorded as an impairment of an intangible asset related to the acquisition of the membership interest in the project and is included in Goodwill and intangible asset impairment on the income statement. See **Note 23** for additional details of a subsequent event.

On Aug. 30, 2004, a TWG-Mechant subsidiary completed the sale of its 50% indirect interest in TIE. In the second quarter of 2004 the company recorded a $151.9 million pretax impairment ($98.7 million after-tax) to record the estimated write-off of the investment reflecting the anticipated sale. This estimate was finalized resulting in an additional $0.4 million pretax impairment ($0.3 million after-tax) being recorded in the third quarter of 2004. See **Note 16** for additional details.

In December 2004, a pretax impairment charge of $8.2 million ($5.9 million after tax) was recognized related to the company's interests in BCH Mechanical. See **Note 23** for details of a subsequent event. The impairment charge and results of operations are reflected in discontinued operations (see **Note 21**).

In December, 2004 as part of its annual impairment review, pretax impairment charges of $21.1 million ($12.8 million after tax) were recognized to write off the remaining value of steam turbines originally planned for use in a cogeneration project. Based on management's review of the market for steam turbines and its refocus on its core businesses, it was determined that the turbines should be written down to fair market value. In December 2003, pretax asset impairment charges of $27.8 million ($17.4 million after tax) were recognized primarily related to the steam turbines and licenses that were also planned for use in a cogeneration project. The charges are reflected in the Other Unregulated segment.

In the first quarter of 2004, Litestream Technologies, LLC, an entity in which TECO Fiber, a subsidiary of TECO Solutions, holds an equity investment, was placed into bankruptcy by creditors. As a result of the bankruptcy, the company recognized a pretax loss of $5.5 million ($3.4 million after tax). The loss on the equity investment in Litestream was determined using the estimated fair value of the company's claims to net assets. The charge is reflected in the Other Unregulated segment.

Additional impairment charges recognized in 2004 include a $2.4 million pretax ($1.5 million after tax) valuation adjustment at TECO Solutions, Inc. (TECO Solutions) related to a district cooling plant, which is reflected in discontinued operations, and a pretax impairment of $0.9 million ($0.6 million after tax) on ocean-going barges at TECO Transport.

As of Dec. 31, 2003, based on the negotiations with potential buyers, including the project lenders, a change in management's expectations regarding an exit strategy in the near term, and management's designation of the Union and Gila River project companies as held for sale, a pretax asset impairment charge of $1,185.7 million ($770.7 million after tax) was recognized and reflected in discontinued operations, in accordance with FAS 144 (see **Note 21** for additional details).

In 2003, TECO Energy recognized a pretax asset impairment charge of $104.1 million ($64.2 million after tax) relating to installment payments made and capitalized under turbine purchase commitments in prior periods. As reported previously and in **Note 13**, certain turbine rights had been transferred from Other Unregulated operations to Tampa Electric in 2002 for use in Tampa Electric's generation expansion activities. These cancellations, made in April 2003, fully terminate all turbine purchase obligations for these entities.

## 19. Restructuring Costs

In 2004, as part of the company's continued focus to exit merchant operations and to grow the core utility operations to provide for centralized oversight along functional lines, certain restructuring activities were implemented. These actions involved seven employees, including officers and other personnel from operations and support services. In September and October of 2003, TECO Energy announced a corporate reorganization to restructure the company along functional lines, consistent with its objectives to grow the core utility operations, maintain liquidity, generate cash and maximize the value in the existing assets. The 2003 actions included the involuntary termination or retirement of 337 employees, including officers and other personnel from operations and support services.

In 2002, TECO Energy initiated a restructuring program that impacted approximately 250 employees across multiple operations and services within, primarily, Tampa Electric. This program included retirements, the elimination of positions and other cost control measures. The total costs associated with this program, included severance, salary continuation and other termination and retirement benefits.

The company recognized a pretax expense of $1.2 million, $24.6 million and $17.8 million for accrued benefits and other termination and retirement benefits for the years ended Dec. 31, 2004, 2003 and 2002, respectively.

**Restructuring Charges**

| *(millions)* *For the years ended Dec. 31,* | *2004* | *2003* | *2002* |
|---|---|---|---|
| Tampa Electric | $ – | $ 9.9 | $16.6 |
| Peoples Gas | 0.7 | 4.1 | – |
| TWG | 0.5 | 0.4 | – |
| TECO Transport | – | 1.7 | – |
| TECO Coal | – | – | – |
| Other Unregulated | – | 5.9 | 1.2 |
| Eliminations and other [1] | – | 2.6 | – |
| Total TECO Energy | $ 1.2 | $24.6 | $17.8 |

(1) This amount relates to charges at TECO Energy parent.

**Accrued Liability for Restructuring Costs**

| *(millions)* | *2004* | *2003* | *2002* |
|---|---|---|---|
| Beginning balance | $15.8 | $ 6.0 | $ 0.2 |
| Charged to income (pretax) | 1.2 | 24.6 | 17.8 |
| Payments and settlements | 16.5 | 14.8 | 12.0 |
| Ending balance | $ 0.5 | $15.8 | $ 6.0 |

## 20. TPGC Joint Venture Termination

In January 2002, TWG (formerly TECO Power Services Corporation) subsidiaries agreed to purchase the interests of Panda Energy in the TPGC projects in 2007 for $60 million, and TECO Energy guaranteed payment of this obligation. Panda Energy obtained bank financing using the purchase obligation and assigned TECO Energy's guarantee as collateral. Under certain circumstances, the purchase obligation could have been accelerated for a reduced price based on the timing of the acceleration. In connection with this purchase obligation, Panda Energy retained a cancellation right, exercisable in 2007 for $20 million by the holder, with early exercise permitted for a reduced price of $8 million.

On Apr. 9, 2003, the TWG subsidiaries and Panda Energy amended the agreements related to the purchase obligation. The modified terms accelerated the purchase obligation to occur on or before Jul. 1, 2003, and reduced the overall purchase obligation to $58 million. Under the guarantee, TWG became obligated to make interest and certain principal payments to or on behalf of Panda related to the collateralized loan obligation of Panda. The purchase obligation of $58 million included $35 million for Panda Energy's interest in TPGC, and a short-term receivable from Panda, collateralized by Panda's remaining interests in PLC (see **Notes 1** and **13** for additional details on TECO Energy's indirect ownership interest in PLC). Both modifications to the purchase obligation were subject to the condition, which TECO Energy could waive, that bank financing be obtained by TECO Energy. Panda Energy's cancellation right was accelerated to expire on Jun. 16, 2003. TECO Energy's guarantee of the TWG subsidiaries' obligation was modified to reflect the amendments to the purchase obligation. In April 2003, TECO Energy recognized the fair value of the guarantee as a pretax loss of $35.0 million ($21.4 million after tax), included in discontinued operations, as a result of the expected disposition of the project companies (see **Note 21**). From April 2003 through June 2003, TECO Energy made and accrued certain principal payments under the guarantee commitment.

As a result of the amendments to these agreements in early April 2003, management believed the exercise of the modified guarantee and the related purchase obligation became highly probable. The likelihood of the exercise of the purchase obligation created a presumption of effective control. When combined with TECO Energy's exposure to the majority of risk of loss under the previously disclosed letters of credit and contractor undertakings, management believed that consolidation of TPGC was appropriate as of the date of the modifications to the agreements. Prior to Apr. 1, 2003, TWG recognized assets of $839.1 million, liabilities of $48.9 million and an unrealized loss in OCI of $69.0 million, to reflect the equity method of accounting for its investment in TPGC. As a result of the consolidation on Apr. 1, 2003, the company recognized additional assets of $2,446.9 million, primarily relating to utility plant and construction work in progress, additional liabilities of $1,976.8 million (including non-recourse debt), and an additional unrealized loss in OCI of $69.0 million for interest rate swaps designated as hedges. See **Note 21** for a discussion of the subsequent designation of the TPGC projects as assets and liabilities held for sale.

In June 2003, TECO Energy satisfied the bank financing condition resulting in the acceleration of TECO Energy's guarantee obligation and executed a final agreement with Panda to effect the termination of Panda's involvement in the partnership. Proceeds from the bank financing obtained in June 2003, which is more fully discussed in **Note 6**, were used to fund the net termination payment to Panda. Upon acceleration of the guarantee obligation and the resulting partnership termination, TWG received the 50% outstanding partnership interests in TPGC. As previously discussed, under the amended agreements, $35.0 million, pretax, had been recognized in April 2003 as the fair value of the guarantee obligation. The remaining amount was recorded as due from Panda and collateralized by Panda's remaining interests in PLC. Foreclosure proceedings were consummated on Panda's remaining interests in PLC in September 2003. As of Dec. 31, 2004 and Dec. 31, 2003 substantially all of the assets and liabilities associated with the TPGC projects (Union and Gila River) were classified as held for sale. All results of operations for these two projects have been reclassified to discontinued operations for all periods presented.

For the year ended Dec. 31, 2003, TWG recorded total pretax charges of $249.1 million ($155.9 million after tax) as a direct result of the consolidation of TPGC. See **Note 21** for a discussion of the remaining amount recorded in discontinued operations.

## 21. Discontinued Operations and Assets Held for Sale

**Union and Gila River Project Companies (TPGC)**

During 2004 an agreement was reached with the steering committee of the lending group for the Union and Gila River power stations on all material terms and forms of definitive agreements for the previously announced sale and transfer to the lenders of ownership of these plants. The lenders process of seeking approval for the transaction to be completed required a 100% approval by the lenders. Two lenders, representing approximately 10% of the debt, dissented. The lending group indicated that in order to facilitate the completion of this transaction, a pre-negotiated Chapter 11 case of the Union and Gila River project entities was likely to be required. A pre-negotiated reorganization can be achieved if the approval of at least one-half of the lenders comprising two-thirds of the amount of debt can be obtained in contrast to the 100% approval contemplated in the consensual sale and transfer (see **Note 23** for details of a subsequent event). No material changes in the terms of the transaction from that previously announced are anticipated. Based on these events, as of Dec. 31, 2004 management expects to complete the transfer of the project entities in 2005, therefore the assets and liabilities of TPGC continue to be reported as held for sale. The Union and Gila River project companies comprised part of the TWG operating segment until designated as assets held for sale in December 2003.

As an asset held for sale, the assets and liabilities that are expected to be transferred as part of the sale, as of Dec. 31, 2004 and 2003, have been reclassified, respectively, in the balance sheet. Furthermore, the company has determined that TPGC meets the criteria of a discontinued operation. Results from operations for the Union and Gila River project companies have been reflected in discontinued operations for all periods presented. For the year ended Dec. 31, 2002 TPGC was a development stage company. The following table provides selected components of discontinued operations for TPGC.

**Components of income from discontinued operations – Union and Gila River Project Companies**

| *(millions)* *For the years ended Dec. 31,* | *2004* | *2003* | *2002* |
|---|---|---|---|
| Revenues | $ 510.7 | $ 319.4 | $ – |
| Asset impairment [1] | – | (1,185.7) | – |
| (Loss) from operations | (33.5) | (1,239.8) | – |
| (Loss) on joint venture termination | – | (153.9) | – |
| (Loss) income before provision for income taxes | (144.9) | (1,441.4) | 27.4 |
| (Benefit) provision for income taxes | (48.9) | (522.7) | 10.6 |
| Net (loss) income from discontinued operations | $ (96.0) | $ (918.7) | $ 16.8 |

(1) Includes charges recognized in accordance with FAS 133.

*Asset impairment charge*

The pretax asset impairment charge of $1,185.7 million ($762.0 million after tax) recorded in 2003 is comprised of an impairment in long-lived assets and a related charge to reflect the impacts of hedge accounting. The asset impairment charge was recognized in accordance with FAS 144. The recognition of the asset impairment effectively accelerated the recognition of previously capitalized interest. As a result, in accordance with cash flow hedge accounting under FAS 133, a reversal from OCI of $22.6 million of pretax losses on the interest rate swaps was required to give effect in the income statement to the previously hedged interest which was capitalized during construction.

In addition, as of Dec. 31, 2003 the change in future expectations regarding the probability of the company retaining the long-term, non-recourse debt resulted in the reversal of an additional $63.8 million pretax losses which were previously deferred in OCI and related to the future recognition of capitalized interest amortization and future interest expense on the non-recourse debt, anticipated to be recognized in periods subsequent to 2004.

*Loss on joint venture termination*

As discussed in greater detail in **Note 20**, the consolidation of TPGC on Apr. 1, 2003 resulted in the recognition of a pretax charge of $153.9 million ($94.7 million after tax) which was recorded in discontinued operations. This pretax charge included: $35.0 million ($21.4 million after tax) related to the partnership termination under the guarantee; and $118.9 million ($73.3 million after tax) related to the consolidation of TPGC to reflect the impact of Panda's portion of TPGC's partnership deficit and the elimination of certain related-party liabilities (see **Note 13**).

The following table provides a summary of the carrying amounts of the significant assets and liabilities reported in the combined current and non-current "Assets held for sale" and "Liabilities associated with assets held for sale" line items:

**Assets held for sale – Union and Gila River Project Companies**

| *(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| Current assets | $ 128.8 | $ 72.9 |
| Net property, plant and equipment | 1,369.0 | 1,367.9 |
| Other investments | 658.5 | 676.1 |
| Other non-current assets | 22.4 | 23.7 |
| Total assets held for sale | $2,178.7 | $2,140.6 |

**Liabilities associated with assets held for sale – Union and Gila River Project Companies**

| *(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| Current portion of long-term debt, non-recourse - Secured Facility Note | **$ 1,395.0** | $ 1,395.0 |
| Other current liabilities | **233.8** | 94.0 |
| Long-term debt, non-recourse Financing Facility Note | **658.5** | 676.1 |
| Other non-current liabilities | **13.7** | 21.7 |
| Total liabilities associated with assets held for sale | **$ 2,301.0** | $2,186.8 |

*Current and non-current assets*

Current assets include $47.9 million and $18.8 million of restricted cash as of Dec. 31, 2004 and 2003, respectively. Also included in current assets is $17.6 million and $16.2 million, as of Dec. 31, 2004 and 2003, respectively, representing the current portion of the investment in Union County bonds, described in Other investments below.

*Net property, plant and equipment*

Net property, plant and equipment has been reduced by accumulated depreciation of $49.4 million and a valuation adjustment of $1,099.3 million as of Dec. 31, 2004 and 2003. In accordance with FAS 144, no depreciation was recognized on TPGC's assets in 2004 as a result of being classified as held for sale. Had TPGC's assets not been classified as held for sale, $84.7 million of depreciation expense would have been recognized in 2004. This impairment charge arose as a result of changes in management's expectations, including its long-term strategic outlook, and is more fully described in **Note 18.** The decline of the fair value of the disposal group (comprised of the assets and liabilities expected to be transferred upon disposition) below the carrying value is principally attributable to the decline in future wholesale power price expectations as a result of the repercussions of the failure of deregulation in California and the Enron bankruptcy; less than economic dispatch in some areas of the country; the U.S. economic slowdown; uncertainty with respect to long-term price recovery; and the significant excess generating capacity in many areas of the country. The primary triggering event for the recognition of the charge by the company was the significant change in management's expectations regarding the company's long-term future involvement in the Union and Gila River project companies and the decision, during the fourth quarter of 2003, to sell the project companies.

*Other investments*

Other investments represent industrial revenue bonds from Union County, Arkansas, which were acquired by Union Power Partners, L.P. (UPP), a subsidiary of TPGC, with financing obtained by borrowings from Union County (the County). As of Dec. 31, 2004 and 2003, respectively, UPP's investment in the bonds from the County (excluding the current position) totaled $658.5 million and $676.1 million, which equals the non-recourse financing facility from the County. The County's debt service payments on the bonds equal UPP's debt service obligations to the County. This agreement provides an incentive to and a means through which the company can invest in the County. For periods prior to Dec. 31, 2003, TECO Energy did not include TPGC in the Consolidated Balance Sheet (see **Note 20**).

Interest income on the investment and interest expense on the related long-term, non-recourse financing have no net impact on the company's results of discontinued operations. The obligation to pay cash under the long-term debt is fully offset by the right to receive cash from the bond issuer. The interest rate and maturity date on both the bonds and the related long-term debt is 7.5% per year and June 2021.

*Current and non-current liabilities*

Included in current liabilities is the current portion of the financing facility due to the County, described in Other investments above, of $17.6 million and $16.2 million as of Dec. 31, 2004 and 2003, respectively. Also included is $68.1 million and $58.6 million as of Dec. 31, 2004 and 2003, respectively, for interest rate swaps entered into by the Union and Gila River projects in connection with the non-recourse collateralized borrowings.

The purpose of the interest rate swap agreement was to effectively convert a portion of the floating-rate debt to a fixed rate. The interest rate swap agreements have terms ranging from 2 to 5 years with the majority maturing in June 2006. As more fully described in **Note 22**, the designation of the secured facility note as a liability associated with assets held for sale resulted in the prospective loss of hedge accounting for the periods beyond the expected effective date of the sale.

*Non-recourse, secured facility note*

In 2001, the Union and Gila River project companies obtained construction financing of $1,395.0 million in the form of floating rate, non-recourse senior secured credit facilities from a bank group. The Union and Gila River project companies each jointly and severally guarantee and cross-collateralize the loans and debts of the other. The loans are non-recourse to TECO Energy, TWG and its subsidiaries that own the project entities.

*Credit Facilities*

The Union and Gila River project companies, as part of the non-recourse project financing, have credit facilities for commercial letters of credit to facilitate gas purchases and power sales. These facilities are recourse only to the project companies, and not to TECO Energy or its other subsidiaries. At Dec. 31, 2004 and 2003, the credit facilities totaled $265.0 million and $200.0 million, respectively, and aggregate letters of credit outstanding under the facilities totaled $181.4 million and $144.2 million, respectively. The project companies also had an $80 million debt reserve facility, which was cancelled in 2004. The Union and Gila River project companies' non-recourse credit facilities have maturity dates of June 2006.

See **Note 23** regarding subsequent events relating to the Union and Gila River projects companies.

**Other transactions**

In 2004, 2003 and 2002, the company completed several sales transactions and achieved significant milestones towards additional transactions anticipated to be completed in 2005. The completed transactions include: the sale of Frontera in 2004; Prior Energy in 2004;TECO BGA in 2004; TECO AGC, Ltd.. in 2004; Hardee Power Partners, Ltd.. (HPP) in 2003; and the sale of TECO Coalbed Methane in 2002 (see **Note 16** for additional details). As a result of the accounting treatment of the sale of HPP, the results from operations of HPP through the date of the sale and for all prior periods presented are included in continuing operations. For all periods presented, the results from operations and gains and losses of Frontera, Prior Energy, TECO BGA, TECO AGC, Ltd.., and TECO Coalbed Methane are presented as discontinued operations on the income statement. As of Dec. 31, 2004, no significant assets or liabilities remained relating to these entities, with the exception of certain cash proceeds held by TECO Energy which are subject to restriction, as described in **Note 1**.

At Dec. 31, 2004, assets and liabilities held for sale–other includes BCH Mechanical and TECO Thermal, both investments of TECO Solutions (see **Note 23** for additional details of a subsequent event including BCH Mechanical). For all periods presented, the results from operations of each of these entities are presented as discontinued operations on the income statement.

The following table provides selected components of discontinued operations for transactions other than the Union and Gila River projects (TPGC) transaction:

**Components of income from discontinued operations – Other**

| *(millions)* *For the years ended Dec. 31,* | *2004* | *2003* | *2002* |
|---|---|---|---|
| Revenues | **$112.0** | $163.2 | $205.1 |
| (Loss) income from operations | **(33.3)** | (110.1) | 38.5 |
| (Loss) gain on sale | **(43.4)** | 39.7 | 12.7 |
| (Loss) income before provision for income taxes [1] | **(80.2)** | (73.3) | 46.8 |
| (Benefit) provision for income taxes | **(28.6)** | (25.2) | 2.0 |
| Net (loss) income from discontinued operations [1] | **$ (51.6)** | $(48.1) | $ 44.8 |

(1) Results for BCH, TECO Thermal, TECO BGA and Prior Energy include internal financing costs, allocated prior to discontinued operations designation. Internally allocated costs for 2004, 2003 and 2002 were at pretax rates of 8%, 8% and 7%, respectively, based on the average investment in each subsidiary.

*Revenues*

Revenues for energy marketing operations at Prior Energy and TECO Gas Services are presented on a net basis in accordance with Emerging Issues Task Force No. (EITF) 99-19, *Reporting Revenue Gross as a Principal versus Net as an Agent,* and EITF 02-3, *Recognition and Reporting of Gains and Losses on Energy Trading Contracts Under Issues No. 98-10 and 00-17,* to reflect the nature of the contractual relationships with customers and suppliers. As a result, costs netted against revenues for the years ended Dec. 31, 2004, 2003 and 2002 were $128.0 million, $853.4 million and $568.3 million, respectively.

*(Loss) Gain on sale*

As a result of the sale of Frontera in December 2004, the company recognized a pretax loss of $42.1 million ($27.0 million after-tax). The sales of Prior Energy and TECO AGC, Ltd.. in 2004 did not result in a material gain or loss to the company.

As a result of the sale of TECO Coalbed Methane in December 2002, the company recognized pretax gains of $39.7 million ($24.1 million after-tax) and $12.7 million ($7.7 million after-tax) for the years ended Dec. 31, 2003 and Dec. 31, 2002, respectively.

The following table provides a summary of the carrying amounts of the significant assets and liabilities reported in the combined current and non-current "Assets held for sale" and "Liabilities associated with assets held for sale" line items for all other transactions described above:

**Assets held for sale – Other**

| *(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| Current assets | $ – | $ 96.5 |
| Net property, plant and equipment | 7.7 | 1.5 |
| Other non-current assets | 1.5 | 8.2 |
| Total assets held for sale | $ 9.2 | $ 106.2 |

**Liabilities associated with assets held for sale – Other**

| *(millions) Dec. 31,* | *2004* | *2003* |
|---|---|---|
| Current liabilities | $ 3.0 | $ 55.4 |
| Total liabilities associated with assets held for sale | $ 3.0 | $ 55.4 |

## 22. Derivatives and Hedging

From time to time, TECO Energy and its affiliates enter into futures, forwards, swaps and option contracts for the following purposes:

- To limit the exposure to price fluctuations for physical purchases and sales of natural gas in the course of normal operations at Tampa Electric and PGS;
- To limit the exposure to interest rate fluctuations on debt securities at TECO Energy and its other affiliates;
- To limit the exposure to electricity, natural gas and fuel oil price fluctuations related to the operations of natural gas-fired and fuel oil-fired power plants at TWG;
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport; and
- To limit the exposure to Section 29 tax credits from TECO Coal's synthetic fuel produced as a result of changes to the reference price of domestically produced oil.

TECO Energy and its affiliates use derivatives only to reduce normal operating and market risks, not for speculative purposes. The company's primary objective in using derivative instruments for regulated operations is to reduce the impact of market price volatility on ratepayers. For unregulated operations, the company uses derivative instruments primarily to optimize the value of physical assets, including generation capacity, natural gas production, and natural gas delivery.

The risk management policies adopted by TECO Energy provide a framework through which management monitors various risk exposures. Daily and periodic reporting of positions and other relevant metrics are performed by a centralized risk management group which is independent of all operating companies.

The company applies the provisions of FAS 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended by FAS138, *Accounting for Certain Derivative Instruments and Certain Hedging Activity* and FAS 149, *Amendment on Statement 133 on Derivative Instruments and Hedging Activities.* These standards require companies to recognize derivatives as either assets or liabilities in the financial statements, to measure those instruments at fair value, and to reflect the changes in the fair value of those instruments as either components of OCI or in net income, depending on the designation of those instruments. The changes in fair value that are recorded in OCI are not immediately recognized in current net income. As the underlying hedged transaction matures or the physical commodity is delivered, the deferred gain or the loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of its reclassification. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the amount paid or received on the underlying physical transaction.

At Dec. 31, 2004 and 2003, respectively, TECO Energy and its affiliates had derivative assets (current and non-current) totaling $3.8 million and $21.1 million, and liabilities (current and non-current) totaling $12.0 million and $12.0 million. At Dec. 31, 2004 and 2003, accumulated other comprehensive income (AOCI) included $0.5 million and ($4.3) million, respectively, of unrealized after-tax gains (losses), representing the fair value of cash flow hedges whose transactions will occur in the future. Included in AOCI at Dec. 31, 2003 was an unrealized after-tax loss of $14.6 million on interest rate swaps designated as cash flow hedges, reflecting the remaining amount included in AOCI related to cash flow hedges for the period preceding the expected disposition of TPGC (see **Note 21**). At Dec. 31, 2002 the unrealized after-tax loss of $37.3 million, included in AOCI, represented the company's proportionate share of AOCI at TPGC, in accordance with the equity method of accounting. Amounts recorded in AOCI reflect the estimated fair value of derivative instruments designated as hedges, based on market prices as of the balance sheet date. These amounts are expected to fluctuate with movements in market prices and may or may not be realized as a loss upon future reclassification from OCI.

For the years ended Dec. 31, 2004, 2003 and 2002, TECO Energy and its affiliates reclassified amounts from OCI (excluding certain reclassifications for interest rate swaps described below) and recognized net pretax gains (losses) of $1.2 million, ($12.6) million and ($29.0) million, respectively. Amounts reclassified from OCI were primarily related to cash flow hedges of physical purchases of natural gas and physical sales of electricity. For these types of hedge relationships, the loss on the derivative, reclassified from OCI to earnings, is offset by the reduced expense arising from lower prices paid or received for spot purchases of natural gas or decreased revenue from sales of electricity. Conversely, reclassification of a gain from OCI to earnings is offset by the increased cost of spot purchases of natural gas or sales of electricity.

As a result of 1) the suspension of construction on the Dell and McAdams power plants at TWG in 2003 and 2) the maintenance activity on the Frontera Power Station at TWG in early 2003, the company discontinued hedge accounting for purchases of natural gas and sales of electricity which were no longer anticipated to take place within two months of the originally designated time period for delivery. The discontinuation of hedge accounting resulted in a reclassification of a pretax gain of $0.2 million from OCI to earnings, reflecting the fair value of the related derivatives as of the discontinuation date. This gain is included in the net pretax loss reported above for 2002. In addition, as a result of the designation of TPGC as an asset held for sale in 2003, the company concluded that the hedged interest expense for periods beyond the expected disposition date were no longer probable. As a result, the company reclassified pretax losses of $24.0 million ($15.6 million after-tax) and $63.8 million ($41.5 million after tax) from OCI to income from discontinued operations in 2004 and 2003, respectively (see **Note 21**). Gains and losses on these derivative instruments, subsequent to the discontinuation of hedge accounting treatment, were recorded in earnings.

Based on the fair value of cash flow hedges at Dec. 31, 2004, pretax losses of $11.5 million are expected to be reversed from OCI to the Consolidated Statements of Income within the next twelve months. However, these losses and other future reclassifications from OCI will fluctuate with movements in the underlying market price of the derivative instruments. The company does not currently have any cash flow hedges for transactions forecasted to take place in periods subsequent to 2006.

During the years ended Dec. 31, 2003 and 2002, respectively, Prior Energy, a subsidiary of TECO Energy, recognized pretax gains (losses) of $(1.3) million and $0.7 million, respectively for transactions that were in place to hedge gas storage inventory that qualified for fair value hedge accounting treatment under FAS 133. These gains and losses are included in discontinued operations as a result of the sale of Prior Energy (see **Notes 16** and **21**).

At Dec. 31, 2004, TECO Energy subsidiaries had derivative assets totaling $3.8 million for transactions that were not designated as either a cash flow or fair value hedge. These derivatives are marked-to-market with fair value gains and losses recognized through earnings. For the years ended Dec. 31, 2004, 2003 and 2002, the company recognized gains (losses) on marked-to-market derivatives of $0.8 million, ($6.5) million and ($2.4) million, respectively.

## *23. Subsequent Events*

**Tampa Electric accounts receivable securitized borrowing facility**

On Jan. 6, 2005, Tampa Electric and TEC Receivables Corp ("TRC"), a wholly-owned subsidiary of Tampa Electric, entered into a $150 million accounts receivable securitized borrowing facility. The assets of TRC are not intended to be generally available to the creditors of Tampa Electric Company. Under the Purchase and Contribution Agreement, Tampa Electric will sell and/or contribute to TRC all of its receivables for the sale of electricity or gas to its customers and related rights (the "Receivables") with the exception of certain excluded receivables and related rights defined in the agreement, and will assign to TRC the deposit accounts into which the proceeds of such Receivables are paid. The Receivables will be sold by Tampa Electric to TRC at a discount. Under the Loan and Servicing Agreement among Tampa Electric as Servicer, TRC as Borrower, certain lenders named therein and Citicorp North America, Inc. as Program Agent, TRC may borrow up to $150 million to fund its acquisition of the Receivables under the Purchase Agreement. TRC will secure such borrowings with a pledge of all of its assets including the Receivables and deposit accounts assigned to it. Tampa Electric will act as Servicer to service the collection of the Receivables. TRC will pay program and liquidity fees based on Tampa Electric's credit ratings. The terms of the Loan and Servicing Agreement include the following financial covenants: (i) for the 12-months ending each quarter-end, the ratio of Tampa Electric's earnings before interest, taxes, depreciation and amortization (EBITDA) to interest, as defined in the agreement, must be equal to or exceed 2.0 times; (ii) at each quarter-end, Tampa Electric's debt to capital, as defined in the agreement, must not exceed 60% and (iii) certain dilution and delinquency ratios with respect to the Receivables, set at levels substantially above historic averages, must be maintained.

**Sale of BCH Mechanical, Inc.**

On Jan. 7, 2005, an indirect subsidiary of TECO Energy completed the disposal of its 100% interest in BCH Mechanical, Inc. ("BCH") pursuant to a Stock Purchase Agreement dated as of Dec. 31, 2004. The purchaser of BCH was BCH Holdings, Inc., the majority owner of which is Daryl W. Blume, who was a Vice President of BCH and one of the owners of BCH when it was purchased by a subsidiary of TECO Energy in September 2000. Under the transaction, TECO Energy retained BCH's net working capital determined as of Dec. 31, 2004, and certain other existing obligations. As a result of asset and goodwill impairments recorded in the fourth quarter 2004 as part of the annual impairment testing, no additional gain or loss was recorded as a result of the completion of the sale (see **Note 18**). See the Other transactions section of **Note 21** for additional details relating to this disposition.

**Agreement to sell membership interests in Commonwealth Chesapeake Company, LLC**

On Jan. 13, 2005, an indirect subsidiary of TECO Energy entered into a Purchase Agreement to sell its membership interests in Commonwealth Chesapeake Company, LLC ("CCC"), the owner of the Commonwealth Chesapeake Power Station in Virginia, to an affiliate of Tenaska Power Fund, L.P. At Dec. 31, 2004, CCC had current assets of $7.0 million, property plant and equipment of $78.4 million, non-current assets of $2.9 million and current liabilities of $1.1 million. Proceeds from the sale are expected to be approximately $86 million after adjustments at closing for the value of fuel, inventory and working capital items, and the payment of transaction-related expenses associated with the sale. The sale is expected to close by the end of the first quarter of 2005, subject to a financing contingency and certain regulatory approvals. As a result of asset impairments recorded in the fourth quarter 2004 as part of the annual impairment testing (see **Note 18**), completion of the sale is not expected to result in a material gain or loss to the company.

**Final settlement of Equity Security Units**

On Jan. 14, 2005, the final settlement rate for TECO Energy's remaining outstanding 7,208,927 equity security units ("units") (NYSE: TE-PRU) that were not tendered in the early settlement offer completed in August 2004 was set based on the average trading price of TECO Energy common stock from the 20 consecutive trading days ending Jan. 12, 2005, as required under the terms of the units. As a result of the final settlement of the purchase contract component of the units, the units ceased trading on the NYSE before the opening of the market on Jan. 14, 2005. On Jan. 18, 2005, each holder of the TECO Energy units purchased from TECO Energy 0.9509 shares of TECO Energy common stock per unit for $25 per share. The cash for the unit holders' purchase obligation was satisfied from the proceeds received upon the maturity of a portfolio of U.S. Treasury securities acquired in connection with the October 2004 remarketing of the trust preferred securities to TECO Capital Trust II. As a result, TECO Energy issued 6.85 million shares of common stock on Jan. 18, 2005 and received approximately $180 million of proceeds from the settlement.

**Transfer of Union and Gila project companies**

On Jan. 24, 2005, 95% in number and 90% in aggregate principal amount of the Union and Gila River project lenders entered into a Master Settlement and Restructuring Support Agreement (the "Master Settlement Agreement") in which they agreed to vote their respective claims in favor of the pre-negotiated Joint Plan of Reorganization (the "Joint Plan"). Because two members of the 40-member lending group failed to agree to the consensual transfer, on Jan. 26, 2005, the Union and Gila River project entities filed Chapter 11 cases which included the Joint Plan in the U.S. Bankruptcy Court for the District of Arizona. For the Joint Plan to be confirmed, it must be approved by an affirmative vote of creditors holding more than 50% in number of obligations and more than two-thirds of the dollar amount of such obligations in each impaired class. The company also consented to the Joint Plan. The project entities are seeking approval of a schedule that contemplates confirmation of the Joint Plan in the March 2005 through May 2005 time frame.

In addition to the Master Settlement Agreement, 100% of the project lenders approved the Master Release Agreement (the "Release") providing for release of all claims against the company and the project entities, and vice versa, which is part of the Joint Plan. The Release becomes effective upon the transfer of the projects at such time as the Joint Plan is confirmed and payment by the company of the $30 million for settlement of all previous existing financial obligations is made. Also on Jan. 24, 2005, the project entities received FERC approval of the transfer of the ownership to the bank lending group.

**FPSC Ruling on Waterborne Fuel Transportation Contract**

In October 2004, Tampa Electric filed with the FPSC a motion for clarification and reconsideration of the disallowance of recovery of costs under its waterborne transportation contract with TECO Transport (see **Note 13**). On Mar. 1, 2005, the FPSC heard oral arguments on the motion and denied Tampa Electric's request for reconsideration and clarification. This decision by the FPSC had no additional impact on Tampa Electric's results as of Dec. 31, 2004.

## 24. Quarterly Data (unaudited)

Financial data by quarter is as follows:

| *(millions, except per share amounts)*<br>*Quarter ended* | *Dec. 31* | *Sep. 30*(1) | *Jun. 30*(1) | *Mar. 31*(1) |
|---|---|---|---|---|
| **2004** | | | | |
| Revenues | $ 660.2 | $705.8 | $ 677.9 | $ 625.2 |
| (Loss) income from operations | $(673.7) | $ 78.0 | $ 84.2 | $ 54.4 |
| Net (loss) income | | | | |
| Net (loss) income from continuing operations(3) | $(409.3) | $ 53.3 | $ (81.0) | $ 32.6 |
| Net (loss) income(3) | $(487.6) | $ 41.3 | $ (108.2) | $ 2.5 |
| Earnings per share (EPS) - basic | | | | |
| EPS from continuing operations | $ (2.05) | $ 0.27 | $ (0.43) | $ 0.17 |
| EPS | $ (2.44) | $ 0.21 | $ (0.57) | $ 0.01 |
| Earnings per share (EPS) - diluted | | | | |
| EPS from continuing operations | $ (2.05) | $ 0.27 | $ (0.43) | $ 0.17 |
| EPS | $ (2.44) | $ 0.21 | $ (0.57) | $ 0.01 |
| Dividends paid per common share | $ 0.19 | $ 0.19 | $ 0.19 | $ 0.19 |
| Stock price per common share(2) | | | | |
| High | $ 15.49 | $ 13.57 | $ 14.60 | $ 15.38 |
| Low | $ 13.40 | $ 11.87 | $ 11.30 | $ 13.86 |
| Close | $ 15.35 | $ 13.53 | $ 11.99 | $ 14.63 |

| *Quarter ended* | *Dec. 31*(1) | *Sep. 30*(1) | *Jun. 30*(1) | *Mar. 31*(1) |
|---|---|---|---|---|
| **2003** | | | | |
| Revenues | $ 598.9 | $716.1 | $ 658.8 | $ 624.5 |
| (Loss) income from operations | $ (17.9) | $ 90.6 | $ 70.1 | $ (3.5) |
| Net (loss) income | | | | |
| Net (loss) income from continuing operations | $ 23.6 | $ 3.9 | $ 50.7 | $ (16.5) |
| Net (loss) income(4) | $(790.7) | $ (19.5) | $ (101.9) | $ 2.7 |
| Earnings per share (EPS) - basic | | | | |
| EPS from continuing operations | $ 0.13 | $ 0.02 | $ 0.29 | $ (0.09) |
| EPS | $ (4.21) | $ (0.11) | $ (0.58) | $ 0.02 |
| Earnings per share (EPS) - diluted | | | | |
| EPS from continuing operations | $ 0.12 | $ 0.02 | $ 0.28 | $ (0.09) |
| EPS | $ (4.20) | $ (0.11) | $ (0.58) | $ 0.02 |
| Dividends paid per common share | $ 0.19 | $ 0.19 | $ 0.19 | $ 0.355 |
| Stock price per common share(2) | | | | |
| High | $ 14.85 | $ 14.20 | $ 13.69 | $ 17.00 |
| Low | $ 11.80 | $ 11.50 | $ 10.05 | $ 9.47 |
| Close | $ 14.41 | $ 13.82 | $ 11.99 | $ 10.63 |

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 21**.
(2) Trading prices for common shares.
(3) Second and fourth quarter results include impairment charges as described in **Note 17** and **Note 18**.
(4) Fourth quarter results include impairment charges related to TPGC, as described in **Note 18**.

## *Management's Report on Internal Control Over Financial Reporting*

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) of the Securities Exchange Act of 1934, as amended. We conducted an evaluation of the effectiveness of our internal control over financial reporting as of Dec. 31, 2004 based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under this framework, our management concluded that our internal control over financial reporting was effective as of Dec. 31, 2004.

PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, has audited management's assessment of the effectiveness of the Company's internal control over financial reporting as of Dec. 31, 2004 as stated in their report herein.

## *Report of Independent Registered Certified Public Accounting Firm*

**To the Board of Directors and Shareholders of TECO Energy, Inc.:**

We have completed an integrated audit of TECO Energy, Inc.'s 2004 consolidated financial statements and of its internal control over financial reporting as of Dec. 31, 2004 and audits of its 2003 and 2002 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

*Consolidated financial statements*

In our opinion, the accompanying consolidated balance sheets and the related statements of income, comprehensive income, cash flows and capital present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at Dec. 31, 2004 and 2003, and the results of their operations and their cash flows for each of the three years in the period ended Dec. 31, 2004 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits 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 of financial statements 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.

As discussed in the Note 2, 15, 7 and 17 to the Financial Statements, the Company adopted the provisions of Financial Accounting Standards Board Interpretation No. 46-R, *"Consolidation of Variable Interest Entities,"* on Jan. 1, 2004, Financial Accounting Standards 143, *"Accounting of Asset Retirement Obligations,"* on Jan. 1, 2003, Financial Accounting Standard 150, *"Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity,"* on Jan. 1, 2003, and Financial Accounting Standard 142, *"Goodwill and Other Intangible Assets,"* on Jan. 1, 2002, respectively.

*Internal control over financial reporting*

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing above, that the Company maintained effective internal control over financial reporting as of Dec. 31, 2004 based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of Dec. 31, 2004, based on criteria established in Internal Control - Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP

Tampa, Florida
March 1, 2005

## Selected Financial Data

| (millions, except per share amounts) Years ended Dec. 31, | 2004 | 2003 | 2002 | 2001 | 2000 |
|---|---|---|---|---|---|
| Revenues [1] | **$ 2,669.1** | $ 2,598.3 | $ 2,510.5 | $ 2,364.9 | $ 2,177.6 |
| Net (loss) income from continuing operations [1] | **$ (404.4)** | $ 61.7 | $ 268.5 | $ 264.0 | $ 225.5 |
| Net (loss) income from discontinued operations [1] | **(147.6)** | (966.8) | 61.6 | 39.7 | 25.4 |
| Cumulative effect of change in accounting principle, net | – | (4.3) | – | – | – |
| Net (loss) income | **$ (552.0)** | $ (909.4) | $ 330.1 | $ 303.7 | $ 250.9 |
| Total assets | **$ 9,476.5** | $10,462.3 | $ 9,078.4 | $ 7,176.2 | $ 6,167.8 |
| Long-term debt | **$ 3,880.0** | $ 4,392.6 | $ 3,324.3 | $ 1,842.5 | $ 1,374.6 |
| Earnings per share (EPS) – basic | | | | | |
| From continuing operations [1] | **$ (2.10)** | $ 0.34 | $ 1.75 | $ 1.96 | $ 1.79 |
| From discontinued operations [1] | **(0.77)** | (5.37) | 0.40 | 0.30 | 0.20 |
| From cumulative effect of change in accounting principle | – | (0.02) | – | – | – |
| EPS basic | **$ (2.87)** | $ (5.05) | $ 2.15 | $ 2.26 | $ 1.99 |
| Earnings per share - diluted | | | | | |
| From continuing operations [1] | **$ (2.10)** | $ 0.34 | $ 1.75 | $ 1.95 | $ 1.77 |
| From discontinued operations [1] | **(0.77)** | (5.36) | 0.40 | 0.29 | 0.20 |
| From cumulative effect of change in accounting principle | – | (0.02) | – | – | – |
| EPS diluted | **$ (2.87)** | $ (5.04) | $ 2.15 | $ 2.24 | $ 1.97 |
| Dividends paid per common share | **$ 0.76** | $ 0.925 | $ 1.41 | $ 1.37 | $ 1.33 |

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 21**.

March 16, 2005

*Notice of Annual Meeting of Shareholders*
*to be held on April 27, 2005*

The Annual Meeting of the Shareholders of TECO Energy, Inc. will be held at the principal office of the Corporation, TECO Plaza, 702 North Franklin Street, Tampa, Florida, on Wednesday, April 27, 2005 at 10:00 a.m., for the following purposes:

1. To elect four directors.
2. To ratify the selection of the Corporation's independent auditor.
3. To consider and act on such other matters as may properly come before the meeting.

Shareholders of record at the close of business on February 17, 2005 will be entitled to vote at the meeting and at any adjournments thereof.

Even if you plan to attend the meeting, you are requested to either mark, sign and date the enclosed proxy card and return it promptly in the accompanying envelope or vote by telephone or internet by following the instructions on the proxy card. If you attend the meeting and wish to vote in person, your proxy will not be used.

By order of the Board of Directors,

D. E. Schwartz, *Secretary*

**TECO Energy, Inc.**
**P. O. Box 111 Tampa, Florida 33601 (813) 228-1111**

*TECO Energy, Inc.*
*P. O. Box 111, Tampa, FL 33601*

## *Proxy Statement*

The enclosed proxy is solicited on behalf of the Board of Directors of TECO Energy, Inc. (the "Corporation") to be voted at the Annual Meeting of Shareholders of the Corporation to be held at the time and place and for the purposes set forth in the foregoing notice. This proxy statement and the enclosed proxy are being mailed to shareholders beginning on or about March 16, 2005.

## *Voting Securities*

As of February 17, 2005, the record date for the determination of shareholders entitled to vote at the meeting, the Corporation had outstanding 206,880,838 shares of Common Stock, $1 par value ("Common Stock"), the only class of stock of the Corporation outstanding and entitled to vote at the meeting. The holders of Common Stock are entitled to one vote for each share registered in their names on the record date with respect to all matters to be acted upon at the meeting.

The presence at the meeting, in person or by proxy, of a majority of the shares outstanding on the record date will constitute a quorum. Abstentions and broker non-votes will be considered as shares present for purposes of determining the presence of a quorum.

A shareholder submitting a proxy may revoke it at any time before it is exercised at the meeting by filing with the Secretary of the Corporation a written notice of revocation, submitting a proxy bearing a later date or attending the meeting and voting in person.

Shares represented by valid proxies received will be voted in the manner specified on the proxies. If no instructions are indicated on the proxy, the proxy will be voted for the election of the nominees for director named below and the ratification of the Corporation's independent auditor.

The affirmative vote of a majority of the Common Stock represented at the meeting in person or by proxy will be required to elect directors. Abstentions will be considered as represented at the meeting and, therefore, will be the equivalent of a negative vote; broker non-votes will not be considered as represented at the meeting.

## *Attending in Person*

Only shareholders or their proxy holders and the Corporation's guests may attend the meeting, and a form of personal photo identification will be required. Directions to the meeting are provided on the inside back cover of the annual report booklet. Admission will be on a first-come, first-served basis. For safety and security reasons, cameras will not be allowed in the meeting, and bags, briefcases and other items will be subject to security check.

For registered shareholders, an admission ticket is attached to your proxy card. Please bring the admission ticket with you to the meeting.

If your shares are held in the name of your broker, bank, or other nominee, you must bring to the meeting an account statement or letter from the nominee indicating that you beneficially owned the shares on February 17, 2005, the record date for voting.

Any persons who do not present proper photo identification and an admission ticket or verification of ownership may not be admitted to the meeting.

## *Election of Directors*

The Corporation's Bylaws provide for the Board of Directors to be divided into three classes, with each class to be as nearly equal in number as possible and to hold office until its successor is elected and qualified. As the term of one class of directors expires, their successors are elected for a term of three years at each annual meeting of shareholders. Messrs. Ausley, Ferman and Whiting have been nominated for reelection to terms expiring in 2008. Mr. Welch has been nominated for reelection to the class of directors whose term expires in 2007, but has indicated he only plans to serve until April 2006. Otherwise, each of these nominees has consented to serve if elected. If any nominee is unable to serve, the shares represented by valid proxies will be voted for the election of such other person as the Board may designate.

The following table contains certain information as to the nominees and each person whose term of office as a director will continue after the meeting. Information on the share ownership of each of these individuals is included under "Share Ownership" on pages 4 and 5.

| *Name* | *Age* | *Principal Occupation During Last Five Years and Other Directorships Held* [(1)] | *Director Since* [(1)] | *Present Term Expires* |
|---|---|---|---|---|
| *DuBose Ausley | 67 | Attorney and former Chairman, Ausley & McMullen (attorneys), Tallahassee, Florida; also a director of Capital City Bank Group, Inc., Huron Consulting Group, Inc. and Sprint Corporation | 1992 | 2005 |
| Sara L. Baldwin | 73 | Private Investor, Tampa, Florida | 1980 | 2006 |
| *James L. Ferman, Jr. | 61 | President, Ferman Motor Car Company, Inc. (automobile dealerships), Tampa, Florida; also a director of Florida Investment Advisers, Inc. and Chairman of The Bank of Tampa and its holding company, The Tampa Banking Company | 1985 | 2005 |
| Luis Guinot, Jr. | 69 | Attorney and former Equity Partner, Shapiro, Sher, Guinot & Sandler, P.A. (attorneys), Washington, D.C.; formerly United States Ambassador to the Republic of Costa Rica | 1999 | 2006 |
| Sherrill W. Hudson | 62 | Chairman of the Board and Chief Executive Officer, TECO Energy, Inc.; formerly Managing Partner for South Florida, Deloitte & Touche LLP (public accounting), Miami, Florida; also a director of Publix Super Markets, Inc. and The Standard Register Company | 2003 | 2006 |
| Tom L. Rankin | 64 | Independent Investment Manager; formerly Chairman of the Board and Chief Executive Officer, Lykes Energy, Inc. (the former holding company for Peoples Gas System) and Lykes Bros. Inc.; also a director of Media General, Inc. | 1997 | 2007 |
| William D. Rockford | 59 | President, Primary Energy Holdings LLC (power generation), Oak Brook, Illinois; formerly Managing Director, Chase Securities Inc. (financial services), New York, New York | 2000 | 2007 |
| William P. Sovey | 71 | Retired; formerly Chairman of the Board and Chief Executive Officer, Newell Rubbermaid Inc. (consumer products), Freeport, Illinois; also a director of Actuant Corporation | 1996 | 2006 |
| J. Thomas Touchton | 66 | President, The Witt-Touchton Company LLC (private investment company), Tampa, Florida | 1987 | 2007 |
| *James O. Welch, Jr. | 73 | Retired; formerly Vice Chairman, RJR Nabisco, Inc. and Chairman, Nabisco Brands, Inc. | 1976 | 2005 |
| *Paul L. Whiting | 61 | President, Seabreeze Holdings, Inc., (consulting and private investments), Tampa, Florida; also Chairman of the Board of Sykes Enterprises, Incorporated and a director of The Bank of Tampa and its holding company, The Tampa Banking Company | 2004 | 2005 |

*Nominee for election as director

(1) All of the directors of the Corporation also serve as directors of Tampa Electric Company, and the period of service shown includes service on Tampa Electric Company's Board prior to the formation of the Corporation on January 15, 1981. On April 15, 1981, the Corporation became the corporate parent of Tampa Electric Company as a result of a reorganization.

**Information about the Board and its Committees**

The Board of Directors held 14 meetings in 2004. All directors attended at least 75 percent of the meetings of the Board and Committees on which they served. The Corporation's policy is for directors to attend the Corporation's Annual Meeting of Shareholders; in 2004, all of the directors attended that meeting. In 2004, the non-management directors met in executive session at least quarterly, and the independent directors met in executive session at least once. The presiding director for the non-management executive sessions rotates alphabetically on a quarterly basis. The Board determined that all of the directors except Messrs. Ausley and Hudson meet the independence standards of the New York Stock Exchange and those set forth in the Corporation's Corporate Governance Guidelines. An excerpt from these Guidelines containing the independence standards set forth therein is attached as Appendix A to this proxy statement.

The Corporation has standing Audit, Compensation, Finance, and Governance and Nominating Committees of the Board of Directors. The Audit, Compensation and Governance and Nominating Committees are comprised exclusively of independent directors, as defined by the listing standards of the New York Stock Exchange. The Corporate Governance Guidelines, the Charters of each Committee and the Code of Ethics applicable to all directors, officers and employees, the *Standards of Integrity*, are available on the Investor Relations page of the Corporation's website, www.tecoenergy.com, or in print to any shareholder who requests them from the Director of Investor Relations, TECO Energy, Inc., P. O. Box 111, Tampa, Florida 33601. Any shareholder wishing to contact either the non-management directors or the Audit Committee may do so by mail at P. O. Box 1648, Tampa, Florida 33601, or by e-mail through the Investor Relations page of the Corporation's website, www.tecoenergy.com.

The Audit Committee met 14 times in 2004; its members are Messrs. Ferman, Rankin, Touchton (Chair) and Whiting. The Board of Directors has determined that Messrs. Rankin and Whiting are audit committee financial experts, as that term has been defined by the Securities and Exchange Commission, and are independent. Additional information about the Audit Committee is included in the Audit Committee Report on page 13.

The Compensation Committee, which met five times in 2004, is composed of Mrs. Baldwin and Messrs. Guinot, Sovey (Chair) and Welch. For additional information about the Compensation Committee, see the Compensation Committee Report on Executive Compensation on pages 6-8.

The Finance Committee, which assists the Board in formulating the financial policies of the Corporation and evaluating significant investments and other financial commitments by the Corporation, met seven times in 2004; its members are Messrs. Ausley, Hudson, Rankin (Chair) and Rockford.

The Governance and Nominating Committee assists the Board with respect to corporate governance matters, including the composition and functioning of the Board. It met five times in 2004, and its members are Mrs. Baldwin and Messrs. Ferman (Chair), Sovey and Touchton. The Committee has the responsibilities set forth in its Charter with respect to identifying individuals qualified to become members of the Board; recommending to the Board when new members should be added to the Board; recommending to the Board individuals to fill vacancies and nominees for the next annual meeting of shareholders; periodically developing and recommending to the Board updates to the Corporate Governance Guidelines; and overseeing the annual evaluation of the Board and its committees. The Governance and Nominating Committee's process for evaluating nominees for director, including nominees recommended by shareholders, is to consider an individual's character and professional ethics, judgment, business and financial experience, expertise and acumen, familiarity with national and international issues affecting business, and other relevant criteria, including the diversity, age, skills and experience of the Board of Directors as a whole. The Governance and Nominating Committee considers suggestions from many sources, including shareholders, regarding possible candidates for director, and has retained a search firm to identify potential director candidates and assist in their evaluation. Mr. Whiting, who was appointed to the Board in November 2004, was recommended to the Governance and Nominating Committee for consideration by a non-management director. The Governance and Nominating Committee reviews the qualifications and backgrounds of all the candidates, as well as the overall composition of the Board, and recommends to the Board the slate of candidates to be nominated for election at the annual meeting of shareholders and the composition of the Board's committees. Shareholder recommendations for nominees for membership on the Board will be given due consideration by the Committee for recommendation to the Board based on the nominee's qualifications in the same manner as all other candidates. Shareholder nominee recommendations should be submitted in writing to the Chairman of the Governance and Nominating Committee in care of the Corporate Secretary.

**Compensation of Directors**

Directors who are not employees or former employees of the Corporation or any of its subsidiaries are paid an annual retainer of $27,000 and attendance fees of $750 for each meeting of the Board of the Corporation, $750 for each meeting of the Board of Tampa Electric Company and $1,000 for each meeting of a standing Committee of the Board on which they serve. (The meeting fee for ad hoc committees formed by the Board ranges from $500 to $1,000.) Each director who serves as a Committee Chairman receives an additional annual retainer of $5,000. Directors may elect to receive all or a portion of their compensation in the form of Common Stock. Directors may also elect to defer any of their cash compensation with a return calculated at either one percent above the prime rate or a rate equal to the total return on the Corporation's Common Stock.

All non-management directors participate in the Corporation's 1997 Director Equity Plan, which allows for a variety of equity-based awards. Currently, each new non-management director receives an option for 10,000 shares of Common Stock and each continuing non-management director receives an annual grant consisting of 500 shares and an option for 2,500 shares of Common Stock. The exercise price for these options is the fair market value of the shares on the date of grant. They are exercisable immediately and expire ten years after grant or earlier as provided in the plan following termination of service on the Board.

## *Certain Relationships and Related Party Transactions*

The Corporation paid legal fees of $1,436,197 for 2004 to Ausley & McMullen, of which Mr. Ausley is an employee.

## *Share Ownership*

The following table sets forth information with respect to all persons who are known to the Corporation to be the beneficial owner of more than five percent of the outstanding Common Stock as of December 31, 2004.

| *Name and Address* | *Shares* | *Percent of Class* |
|---|---|---|
| Franklin Resources, Inc ("Franklin")<br>Charles B. Johnson<br>Rupert H. Johnson<br>One Franklin Parkway, San Mateo, CA 94403 | 18,746,080 (1) | 9.4 |

(1) Based on a Schedule 13G filed with the Securities and Exchange Commission on February 14, 2005, which reported that Franklin (and Charles B. Johnson and Rupert H. Johnson, as its principal shareholders) had sole voting power and investment power over these shares. Franklin and the Messrs. Johnson disclaim beneficial ownership of any of these shares. The Franklin-affiliated entities that purchased shares directly from the Corporation in 2003 have agreed to vote their shares, to the extent that the shares owned by them and the other Franklin-affiliated entities exceed five percent of the Corporation's outstanding Common Stock, in the same manner (proportionately) as all other shares of Common Stock entitled to vote on the matter, unless otherwise approved in writing in advance by the Corporation.

The following table sets forth the shares of Common Stock beneficially owned as of January 31, 2005 by the Corporation's directors and nominees, its executive officers named in the summary compensation table below and its directors and executive officers as a group. Except as otherwise noted, such persons have sole investment and voting power over the shares. The number of shares of the Corporation's Common Stock beneficially owned by any director or executive officer does not exceed 1% of such shares outstanding at January 31, 2005; the percentage beneficially owned by all directors and executive officers as a group as of such date is 1.3%.

| *Name* | *Shares (1)* | *Name* | *Shares (1)* |
|---|---|---|---|
| DuBose Ausley | 59,577 | James O. Welch, Jr. | 145,586 (6) |
| Sara L. Baldwin | 51,101 (2) | Paul L. Whiting | 10,000 |
| James L. Ferman, Jr. | 71,646 (3) | Robert D. Fagan | 808,861 (7)(8) |
| Luis Guinot, Jr. | 25,325 | John B. Ramil | 321,596 (8)(9) |
| Sherrill W. Hudson | 69,838 (4) | Gordon L. Gillette | 169,634 (8) |
| Tom L. Rankin | 755,428 (5) | William N. Cantrell | 307,304 (8)(10) |
| William D. Rockford | 27,613 | Jimmy J. Shackleford | 162,446 (8) |
| William P. Sovey | 43,082 | All directors and executive officers as a group (19 persons) | 2,652,335 (7)(8)(11) |
| J. Thomas Touchton | 71,792 | | |

(1) The amounts listed include the following shares that are subject to options granted under the Corporation's stock option plans that are exercisable within 60 days of January 31, 2005: Mrs. Baldwin and Messrs. Ausley, Ferman, Guinot, Touchton and Welch, 22,000 shares each; Mr. Hudson, 15,000 shares; Mr. Rankin, 26,000 shares; Mr. Rockford, 17,000 shares; Mr. Sovey, 28,000 shares; Mr. Whiting,

10,000 shares; Mr. Fagan, 784,742 shares; Mr. Ramil, 198,322 shares; Mr. Gillette, 95,309 shares; Mr. Cantrell, 164,350 shares; Mr. Shackleford, 103,143 shares and all directors and executive officers as a group, 1,006,203.

(2) Includes 381 shares held by a trust of which Mrs. Baldwin is a trustee.

(3) Includes 42,429 shares owned jointly by Mr. Ferman and his wife. Also includes 2,197 shares owned by Mr. Ferman's wife, as to which shares he disclaims any beneficial interest.

(4) Includes 2,500 shares owned jointly by Mr. Hudson and his wife.

(5) Includes 1,343 shares owned by Mr. Rankin's wife, as to which shares he disclaims any beneficial interest.

(6) Includes 41,990 shares owned by Mr. Welch's wife, as to which shares he disclaims any beneficial interest. Also includes 36,860 shares held by trusts of which Mr. Welch is a trustee.

(7) Mr. Fagan was the Corporation's Chairman, President and Chief Executive Officer until he resigned from the Corporation and as a director effective July 6, 2004. Mr. Fagan is included as a named executive officer in the Summary Compensation Table because he served as the Corporation's Chief Executive Officer for a portion of fiscal year 2004. Accordingly, the amounts for "all directors and executive officers as a group" in this table and in footnotes (1) and (8) exclude shares attributable to Mr. Fagan.

(8) The amounts listed include the following shares that are held by benefit plans of the Corporation for an officer's account: Mr. Fagan, 1,976 shares; Mr. Ramil, 6,565 shares; Mr. Gillette, 8,566 shares; Mr. Cantrell, 12,025 shares; Mr. Shackleford, 5,539 shares and all directors and executive officers as a group, 59,136 shares.

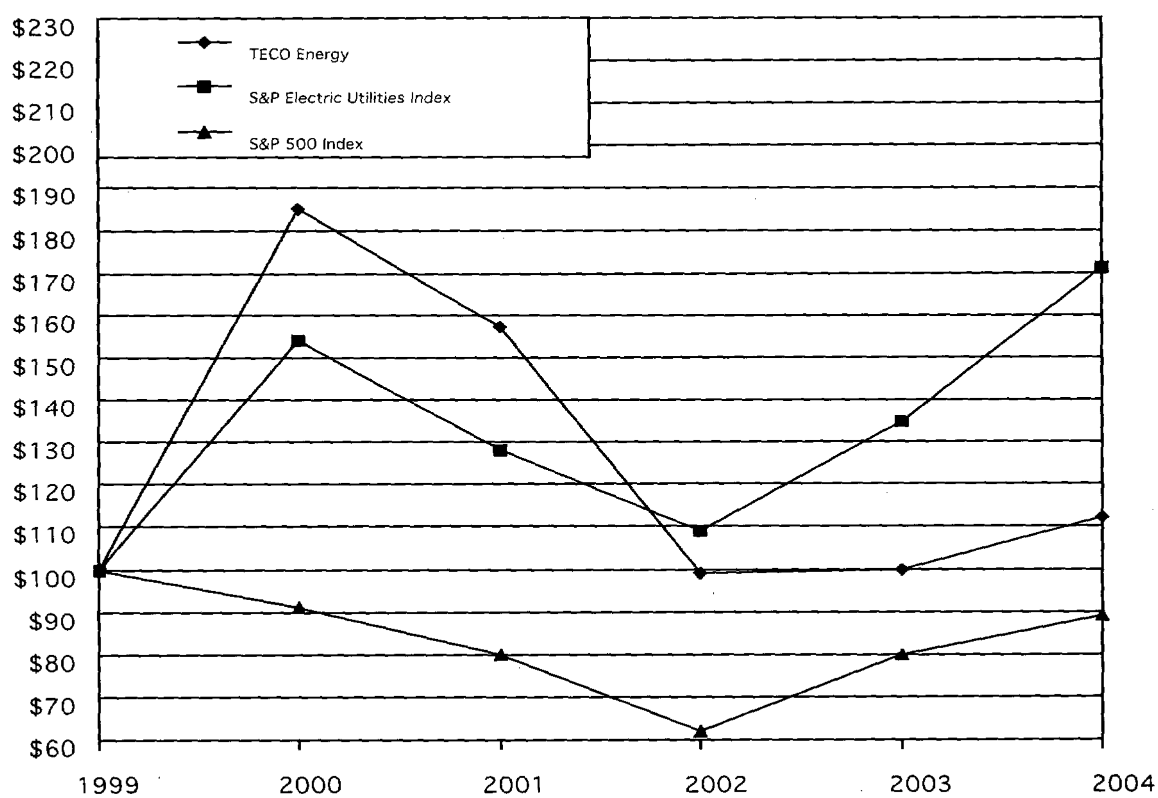
(9) Includes 2,013 shares owned jointly by Mr. Ramil and other family members.

(10) Includes 26,240 shares owned by Mr. Cantrell's wife, as to which shares he disclaims any beneficial interest.

(11) Includes a total of 48,024 shares owned jointly. Also includes a total of 71,770 shares owned by spouses, as to which shares beneficial interest is disclaimed.

## *Shareholder Return Performance Graph*

The following graph shows the cumulative total shareholder return on the Corporation's Common Stock on a yearly basis over the five-year period ended December 31, 2004, and compares this return with that of the S&P 500 Composite Index and the S&P Electric Utilities Index. The graph assumes that the value of the investment in the Corporation's Common Stock and each index was $100 on December 31, 1999 and that all dividends were reinvested.




| *December 31,* | *1999* | *2000* | *2001* | *2002* | *2003* | *2004* |
|---|---|---|---|---|---|---|
| TECO Energy, Inc. | $100 | $185 | $157 | $ 99 | $100 | $112 |
| S&P Electric Utilities Index | $100 | $154 | $128 | $109 | $135 | $171 |
| S&P 500 Index | $100 | $ 91 | $ 80 | $ 62 | $ 80 | $ 89 |

## *Executive Compensation*

**Compensation Committee Report on Executive Compensation**

The Compensation Committee of the Board of Directors, composed entirely of independent directors, reviews and approves the goals and objectives relevant to CEO compensation, evaluates the CEO's performance in light of those goals and objectives, and determines and approves the CEO compensation level based on this evaluation. In addition, the Committee makes recommendations to the Board with respect to the compensation of other executive officers, incentive compensation plans, and equity-based plans. The Committee also administers the Corporation's long-term incentive plan and makes recommendations on proposed executive employment, severance and change in control agreements. The objective of the Corporation's compensation program is to enhance shareholder value by attracting and retaining the talent needed to manage and build the Corporation's businesses. The Committee seeks, therefore, to provide compensation opportunities that are competitive and link the interests of shareholders and executives.

Upon the Committee's recommendation, the Board has adopted stock ownership guidelines of five times base salary for the CEO and three times base salary for the other executive officers. These guidelines, which allow the executives five years to acquire this amount of stock and do not recognize stock options as shares owned, have been in place since 1996.

The components of the Corporation's executive compensation program, base salary, annual incentive awards and long-term incentive awards, are described below.

*Base Salary.* Base salary is designed to provide each executive with a fixed amount of annual compensation that is competitive with the marketplace. The Corporation's salary structure for its executive officers utilizes various salary grade ranges and associated midpoints. Each executive officer is assigned to a salary grade by the Board, on the recommendation of the Committee, based on the officer's experience level and scope of responsibility and a market assessment of the median compensation paid to executives with similar positions by organizations having comparable revenues in the energy services industry and in general industry. (Because the Corporation has non-utility subsidiaries, it does not benchmark compensation only against companies in the S&P Electric Utility Index.) This assessment is conducted by the international compensation consulting firm which serves as the Committee's outside compensation consultant. Each year, the Committee adjusts the salary ranges based on surveys by outside consultants of expected changes in compensation levels at general industrial and energy services companies and recommends adjustments to the base salaries for the executive officers. In recommending base salary adjustments for the executive officers, the Committee typically takes into account the midpoint of the officer's assigned salary grade and the Committee's evaluation of the officer's individual performance. In 2004, Mr. Hudson's initial base salary was set based on the competitive compensation data provided by the Committee's outside consultant, and increases were made to the existing base salaries for each other executive officer. In making these increases, the Committee took into account the midpoint of the officer's assigned salary grade and the Committee's evaluation of the officer's individual performance. Mr. Hudson, who began serving as Chief Executive Officer in July 2004, was paid a base salary consisting of (i) cash paid at the rate of $150,000 per year and (ii) 43,731 shares of restricted stock vesting quarterly until June 30, 2005. This restricted stock, which was valued at $525,000 at the time of grant, was awarded in order to provide an annual base salary consisting primarily of equity-based pay with a total value of $675,000, the same value as the cash base salary of the predecessor CEO (Robert D. Fagan). As he is maintaining a residence in Miami, Mr. Hudson also received a housing allowance of $3,500 per month and was reimbursed for temporary living expenses. Mr. Hudson does not participate in the Corporation's supplemental executive retirement plan. For 2004, Mr. Fagan's and Mr. Hudson's annualized base salaries (including, in the case of Mr. Hudson, the value of the restricted stock referenced above) were 95% of the midpoint of their respective salary grades.

*Annual Incentive Awards.* The Corporation has an annual incentive program intended to encourage actions that contribute to improved operating and financial results, which provides for incentive awards based on the achievement of corporate and individual performance goals. Under the Corporation's plan, financial results are adjusted to exclude one-time gains and losses that were not contemplated in the Corporation's business plan. Target award percentages range up to 70% for the CEO, 40-65% for the other named executive officers and lower percentages for other officers, and are multiplied by the greater of the midpoint of the officer's salary range or the officer's salary. In setting these percentages, the Committee used data from the market assessment referred to above. Under the Corporation's plan, additional payments of up to 50% of the target awards may be made if the goals are exceeded; lesser amounts may be paid if the goals are not achieved, but only if the Corporation's net income, as adjusted, exceeds a threshold designated for that year. The Committee may decide to adjust awards if the plan formula would unduly penalize or reward management and, in individual cases, to vary the calculated award based on the officer's total performance.

The 2004 objectives for all the executive officers under the incentive program included overall operating and financial performance targets measured by the Corporation's non-GAAP earnings, cash utilization and operating unit financial performance on an absolute basis and by the Corporation's earnings per share growth and return on equity relative to other companies in the utility industry. 60% of Mr. Fagan's and Mr. Hudson's potential 2004 awards were based on these factors. Additional quantitative targets were used for some of the other executive officers including, in the case of certain officers, targets relating specifically to the performance of the companies for which they have chief operating responsibility.

In addition to having these quantitative targets, each executive officer had qualitative objectives that focused on aspects of the Corporation's business that directly related to the executive officer's individual responsibilities. 40% of Mr. Fagan's and Mr. Hudson's potential 2004 awards were based on qualitative objectives relating to corporate performance, effective execution of corporate strategy and the demonstration of leadership through safety, diversity, affirmative action and leadership development.

The Committee determined the annual incentive awards for 2004 by (i) calculating the amount of the payment under the plan that would otherwise be payable to each participant based upon satisfaction of the pre-established performance goals (with financial results adjusted for: one-time losses from 2004 hurricane costs, a charge incurred in 2004 for the hedging of oil prices in 2005 and acceleration of certain cash payments into 2004 that were budgeted for 2005); (ii) exercising the Committee's discretion in some cases to reduce the award otherwise payable under the plan, given the Corporation's overall financial performance as a result of the large write-offs recorded by the Corporation in 2004; and (iii) deciding in some cases to pay half or all of the value of the award in stock. Mr. Hudson's annual incentive award for 2004 was paid in the form of common stock having a value equal to 41% of the midpoint of his salary grade. Mr. Fagan did not receive an incentive award for 2004, as his employment terminated during that year and he received a severance package as described below in this report.

In April 2005, the Committee will determine whether or not the pre-established performance goals for 2004 relating to the Corporation's relative performance to peer group companies were achieved and will make any corresponding payments to the executives of the balance of the 2004 annual incentive award.

*Long-Term Incentive Awards.* The long-term component of the Corporation's incentive compensation program consists of equity-based grants, which have been in the form of stock options and restricted stock. These grants are designed to create a mutuality of interest with shareholders by motivating the CEO and the other executive officers and key personnel to manage the Corporation's business so that the shareholders' investment will grow in value over time. The Committee's policy has been to base individual awards on an annual study by its outside consultant comparing the value of long-term incentive grants to salary levels in the energy services industry and in general industry.

In granting these awards, the Committee was aware that each year in the late March-April time frame, the restricted stock granted three years earlier will vest if the applicable vesting conditions are met and, thus, each year at this time, shares may be sold by the executive officers or withheld by the Corporation in order to pay the taxes due upon vesting. Accordingly, investors who see the reported sales of these shares by executive officers should not assume that such sales represent negative views of the Corporation's prospects by the executive officers.

The 37,701 shares of performance-based restricted stock, 37,701 shares of time-vested restricted stock and 227,115 options granted to Mr. Fagan in 2004 reflected the policies described above and, as in the case of the other executive officers, the results of the Committee's review of their performance conducted in early 2004. The 150,000 options granted to Mr. Hudson in July of 2004 reflect the data provided by the Committee's outside consultant as to a competitive long-term incentive package for an incoming CEO. The exercise prices for Mr. Hudson's options were fair market value ("FMV") for one-third, 105% of FMV for one-third and 110% of FMV for one-third. As Mr. Hudson began serving as an executive officer in July 2004, he did not receive any of the performance-based restricted stock awards which were granted to the executive officers in April 2004.

The performance-based restricted stock granted in 2004 has a payout that is dependent upon the total return of the Common Stock over a three-year period relative to that of the median company (in terms of total return) in the Dow Jones Electric Utility Index. (This index was selected because it allows for more readily available computations of the total return of a peer group than the S&P Electric Utility Index.) If the Common Stock's total return is equal to that of the median company during the three-year period, the payout will be equal to 90 percent of the target amount. If the total return is in the top 10 percent of the companies in the index, the payout will be at 200 percent. If the total return is in the bottom one-third of these companies, there will be no payout. A minimum payout of 50 percent of target will be made if performance is equal to the 33 1/3 percentile. The payout for performance between the top 10 percent and the bottom one-third is prorated. The time-vested restricted stock granted in 2004 vests following three years of service. The stock options granted in 2004 vest over a three-year period and have a ten-year term.

As part of the Corporation's internal reorganization in 2004, the Corporation entered into agreements with two executive officers (Richard Lehfeldt and D. Jeffrey Rankin) providing for severance benefits that were recommended by the Committee. The Committee's policy has been to provide severance arrangements that are based on the officer's existing compensation and within the bounds of competitive practice, based on information from its outside consultant. These agreements were filed as exhibits to the Corporation's periodic reports filed with the Securities and Exchange Commission.

Mr. Fagan resigned as Chief Executive Officer of the Corporation effective July 6, 2004. The Corporation fulfilled its contractual commitments under Mr. Fagan's severance agreement dated January 28, 2003, the principal terms of which are described below under "Employment, Termination and Change in Control Arrangements."

With respect to qualifying compensation paid to executive officers under Section 162(m) of the Internal Revenue Code, the Corporation does not expect to have a significant amount of compensation exceeding the $1 million per person annual limitation. Accordingly, the Committee has recommended that the Corporation continue to structure its executive compensation program to meet the objectives described in this report. Compensation attributable to the Corporation's performance-based restricted stock and stock options is not subject to the Section 162(m) limit because of the performance-based exemption.

By the Compensation Committee,
William P. Sovey (Chairman)
Sara L. Baldwin
Luis Guinot, Jr.
James O. Welch, Jr.

The following tables set forth certain compensation information for each person who served as Chief Executive Officer of the Corporation in 2004 and each of the four other most highly compensated executive officers of the Corporation and its subsidiaries in 2004.

## *Summary Compensation Table*

| | | — Annual Compensation — | | | — Long-Term Compensation — | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | — Awards — | | - Payouts - | |
| *Name and Principal Position* | *Year* | *Salary* | *Bonus* (1) | *Other Annual Compen-sation* (2) | *Restricted Stock Awards* (3) | *Shares Underlying Options/SARs (#)* | *LTIP Payouts* (4) | *All Other Compensation* (5) |
| Sherrill W. Hudson<br>Chairman and CEO (6) | 2004 | $70,962 | $292,512 | $21,000 | $525,000 | 150,000 | | $ 21,372 |
| Robert D. Fagan | 2004 | 562,500 | 0 | | 508,964 | 227,115 | $1,021,676 | 3,726,910 |
| Former Chairman, | 2003 | 675,000 | 0 | | 798,268 | 99,671 | | 43,828 |
| President and CEO (7) | 2002 | 675,000 | 475,954 | | 857,082 | 168,110 | 825,700 | 55,543 |
| John B. Ramil | 2004 | 449,154 | 165,000 | | 228,110 | 101,786 | | 20,686 |
| President and | 2003 | 370,000 | 0 | | 305,433 | 34,233 | | 22,689 |
| Chief Operating Officer | 2002 | 370,000 | 203,500 | | 263,190 | 51,622 | 214,538 | 28,484 |
| Gordon L. Gillette | 2004 | 384,154 | 115,000 | | 162,932 | 72,705 | | 17,235 |
| Executive Vice President | 2003 | 290,000 | 0 | | 145,981 | 16,710 | | 16,217 |
| and Chief Financial Officer | 2002 | 290,000 | 130,500 | | 143,701 | 28,188 | 147,563 | 19,902 |
| William N. Cantrell | 2004 | 345,000 | 67,000 | | 138,105 | 61,626 | | 11,886 |
| President of Peoples | 2003 | 315,000 | 0 | | 199,211 | 24,364 | | 19,260 |
| Gas System | 2002 | 315,000 | 158,445 | | 209,505 | 41,094 | 195,210 | 21,951 |
| Jimmy J. Shackleford | 2004 | 265,200 | 170,000 | | 83,795 | 37,391 | | 9,518 |
| President of TECO | 2003 | 255,000 | 0 | | 129,227 | 16,710 | | 16,016 |
| Coal Corporation | 2002 | 255,000 | 133,749 | | 143,701 | 28,188 | 103,765 | 17,979 |

(1) Because the portion of each executive officer's annual bonus that is based on the Corporation's annual earnings per share growth and return on equity relative to that of other companies in the industry is determined using comparative data that does not become available until after the time of printing of the Corporation's proxy statement for that year, this portion of the annual bonus, if any, is reported in the Corporation's proxy statement for the following year. Mr. Hudson's 2004 bonus was paid in the form of stock. One-half of Mr. Ramil's 2004 bonus and Mr. Gillette's 2004 bonus were paid in the form of stock, with half of this stock vesting immediately and half vesting one year from the date of grant.

(2) The reported amount consists of a housing allowance of $3,500 per month for the last six months of 2004, in recognition of Mr. Hudson's retaining his residence in Miami. In addition, Mr. Hudson was reimbursed for temporary living expenses during that period of time.

(3) Of the reported restricted stock, the only shares awarded that vest in less than three years from the date of grant are the 43,731 shares Mr. Hudson received upon his election as Chairman and CEO on July 6, 2004, which were granted in lieu of salary for the period of July 2004 through June 2005. These shares vest quarterly over a 12-month period, and thus 10,933 shares will vest on March 31, 2005 and the same number will vest on June 30, 2005. The reported values of the restricted stock awards were determined using the closing market price of the Common Stock on the date of grant. Restricted stock holdings and the values thereof based on the closing price of the Common Stock on December 31, 2004 were as follows: Mr. Hudson, 21,865 shares ($335,409); Mr. Ramil, 101,256 shares ($1,553,267); Mr. Gillette, 56,152 shares ($861,372); Mr. Cantrell, 70,836 shares ($1,086,624); and Mr. Shackleford, 53,128 shares ($814,984). Holders of restricted stock receive the same dividends as holders of other shares of Common Stock.

(4) The reported amount for Mr. Fagan in 2004 reflects performance-based restricted stock which vested under the terms of his severance agreement, as described in "Employment, Termination and Change in Control Arrangements" below.

(5) The reported amounts for 2004 consist of $372 in premiums paid by the Corporation to the Executive Supplemental Life Insurance Plan, with the balance in each case, except for Mr. Fagan, being employer contributions under the TECO Energy Group Retirement Savings Plan and Retirement Savings Excess Benefit Plan. The reported amount for Mr. Fagan includes a payment of $3,693,774 under his severance agreement, which represented the payment of two-times annual salary and incentive award and the additional retirement benefit described in "Employment, Termination and Change in Control Arrangements" below.

(6) Mr. Hudson began serving as Chairman and CEO on July 6, 2004. His annualized cash salary for 2004 was $150,000.

(7) Mr. Fagan resigned as an officer of the Corporation effective July 6, 2004.

## Option/SAR Grants in Last Fiscal Year

| Name | Number of Shares Underlying Options/SARs Granted (1) | % of Total Options/SARs Granted to Employees in Fiscal Year | Exercise or Base Price Per Share | Expiration Date | Grant Date Present Value (2) |
|---|---|---|---|---|---|
| | Individual Grants | | | | |
| Sherrill W. Hudson | 50,000 | | $ 12.005 | 7/6/14 | |
| | 50,000 | | 12.605 | 7/6/14 | |
| | 50,000 | | 13.206 | 7/6/14 | |
| | 150,000 | 6.28 | | | $313,684 |
| Robert D. Fagan(3) | 227,115 | 9.51 | 13.500 | 4/27/14 | 508,658 |
| John B. Ramil | 101,786 | 4.26 | 13.500 | 4/27/14 | 227,965 |
| Gordon L. Gillette | 72,705 | 3.04 | 13.500 | 4/27/14 | 162,834 |
| William N. Cantrell | 61,626 | 2.58 | 13.500 | 4/27/14 | 138,021 |
| Jimmy J. Shackleford | 37,391 | 1.57 | 13.500 | 4/27/14 | 83,743 |

(1) The options are exercisable in three equal annual installments beginning one year from the date of grant.

(2) The values shown are based on the Black-Scholes valuation model and are stated in current annualized dollars on a present value basis. The key assumptions used for purposes of this calculation include the following: (a) a 3.98% discount rate; (b) a volatility factor based upon the average trading price for the 36-month period ending March 30, 2004; (c) a dividend factor based upon the 3-year average dividend paid for the period ending March 30, 2004; (d) the 10-year option term; and (e) an exercise price equal to the fair market value on the date of grant. The values shown have not been reduced to reflect the non-transferability of the options or the vesting or forfeiture provisions. The actual value an executive may realize will depend upon the extent to which the stock price exceeds the exercise price on the date the option is exercised. Accordingly, the value, if any, realized by an executive will not necessarily be the value determined by the Black-Scholes model.

(3) In connection with his resignation, the stock options reported for Mr. Fagan became immediately exercisable. For additional information, see "Employment, Termination and Change in Control Arrangements."

## Aggregated Option/SAR Exercises in Last Fiscal Year and Fiscal Year-End Option/SAR Value

| Name | Shares Acquired on Exercise (#) | Value Realized ($) | Number of Shares Underlying Unexercised Options/SARs at Fiscal Year-End: Exercisable/ Unexercisable | Value of Unexercised In-The-Money Options/SARs at Fiscal Year-End: Exercisable/ Unexercisable |
|---|---|---|---|---|
| Sherrill W. Hudson | 0 | 0 | 15,000 / 150,000 | $ 32,163 / 410,210 |
| Robert D. Fagan | 0 | 0 | 784,782 / 0 | 841,992 / 0 |
| John B. Ramil | 0 | 0 | 198,322 / 141,815 | 48,544 / 284,394 |
| Gordon L. Gillette | 0 | 0 | 95,309 / 93,241 | 23,700 / 181,178 |
| William N. Cantrell | 0 | 0 | 164,350 / 91,566 | 34,559 / 182,502 |
| Jimmy J. Shackleford | 0 | 0 | 103,143 / 57,927 | 23,700 / 116,200 |

## *Long-Term Incentive Plans – Awards in Last Fiscal Year*

| | | | *Estimated future payouts* | | |
|---|---|---|---|---|---|
| *Name* | *Number of shares, units or other rights* | *Performance or other period until maturation or payout* | *Threshold (#)* | *Target (#)* | *Maximum (#)* |
| Sherrill W. Hudson | 0 | | | | |
| Robert D. Fagan | 37,701 | April 1, 2004 to March 31, 2007 | 18,851 | 37,701 | 75,402 |
| John B. Ramil | 16,897 | April 1, 2004 to March 31, 2007 | 8,449 | 16,897 | 33,794 |
| Gordon L. Gillette | 12,069 | April 1, 2004 to March 31, 2007 | 6,035 | 12,069 | 24,138 |
| William N. Cantrell | 10,230 | April 1, 2004 to March 31, 2007 | 5,115 | 10,230 | 20,460 |
| Jimmy J. Shackleford | 6,207 | April 1, 2004 to March 31, 2007 | 3,104 | 6,207 | 12,414 |

For additional information about the 2004 awards of performance-based restricted stock, see the section of the Compensation Committee Report on Executive Compensation entitled "Long-Term Incentive Awards" on page 7.

**Pension Table**

The following table shows estimated annual benefits payable under the Corporation's pension plan arrangements for the named executive officers other than Mr. Fagan, whose retirement benefits are described below, and Mr. Hudson, who does not participate in the Corporation's pension plan arrangements. Should Mr. Hudson remain employed by the Corporation for five years or more, he will receive pension benefits under the Corporation's defined benefit plan which covers all full-time employees with five years or more of service. His benefit at that time would be a one-time payment valued at 55.5% of his final average earnings under that plan (which earnings as of December 31, 2004 were $150,000).

| | *Years of Service* | | | |
|---|---|---|---|---|
| *Final Average Earnings* | *5* | *10* | *15* | *20 or More* |
| $300,000 | $ 45,000 | $ 90,000 | $135,000 | $180,000 |
| 350,000 | 52,500 | 105,000 | 157,500 | 210,000 |
| 400,000 | 60,000 | 120,000 | 180,000 | 240,000 |
| 450,000 | 67,500 | 135,000 | 202,500 | 270,000 |
| 500,000 | 75,000 | 150,000 | 225,000 | 300,000 |
| 550,000 | 82,500 | 165,000 | 247,500 | 330,000 |
| 600,000 | 90,000 | 180,000 | 270,000 | 360,000 |
| 650,000 | 97,500 | 195,000 | 292,500 | 390,000 |
| 700,000 | 105,000 | 210,000 | 315,000 | 420,000 |
| 750,000 | 112,500 | 225,000 | 337,500 | 450,000 |
| 800,000 | 120,000 | 240,000 | 360,000 | 480,000 |
| 850,000 | 127,500 | 255,000 | 382,500 | 510,000 |
| 900,000 | 135,000 | 270,000 | 405,000 | 540,000 |
| 950,000 | 142,500 | 285,000 | 427,500 | 570,000 |

The annual benefits payable to each of the named executive officers participating in the Corporation's pension plan arrangements are equal to a stated percentage of such officer's final average earnings multiplied by his number of years of service, up to a stated maximum. Final average earnings are based on the greater of (a) the officer's final 36 months of earnings or (b) the officer's highest three consecutive calendar years of earnings out of the five calendar years preceding retirement. The amounts shown in the table are based on 3% of such earnings and a maximum of 20 years of service. The amount payable to Mr. Fagan, who retired in 2004, was based on 20% of earnings plus 4% of earnings for each of his five years of service. Mr. Fagan received a lump sum distribution of $6,644,436 in 2004.

The earnings covered by the pension plan arrangements are the same as those reported as salary and bonus in the summary compensation table above. Years of service for the named executive officers participating in the Corporation's pension plan arrangements are as follows: Mr. Ramil (28 years), Mr. Gillette (23 years), Mr. Cantrell (29 years) and Mr. Shackleford (21 years). The pension benefit is computed as a straight-life annuity commencing at the officer's normal retirement age and is reduced by the officer's Social Security benefits. The normal retirement age is 63 for Messrs. Cantrell and Shackleford, 63 and 2 months for Mr. Ramil and 64 for Mr. Gillette.

The present value of the officer's pension benefit is, at the election of the officer, payable in the form of a lump sum. The pension plan arrangements also provide death benefits to the surviving spouse of an officer equal to 50% of the benefit payable to the officer. If the officer dies during employment before reaching his normal retirement age, the benefit is based on the officer's service as if his employment had continued until such age. The death benefit is payable for the life of the spouse.

**Employment, Termination and Change in Control Arrangements**

The Corporation has severance agreements with the named executive officers under which payments will be made under certain circumstances in connection with a change in control of the Corporation. A change in control means in general an acquisition by any person of 30% or more of the Common Stock, a change in a majority of the directors, a merger or consolidation of the Corporation in which the Corporation's shareholders do not have at least 65% of the voting power in the surviving entity or a liquidation or sale of the assets of the Corporation. Each of these officers is required, subject to the terms of the severance agreements, to remain in the employ of the Corporation for one year following a potential change in control (as defined) unless a change in control earlier occurs. The severance agreements provide that in the event employment is terminated by the Corporation without cause (as defined) or by one of these officers for good reason (as defined) in contemplation of or following a change in control, or, in the case of certain executive officers, if the officer terminates his employment for any reason during the 13th month following a change in control, the Corporation will make a lump sum severance payment to the officer of three times (in the case of Mr. Hudson, one times) annual salary and bonus. In such event, the severance agreements also provide for: (a) a cash payment equal to the additional retirement benefit which would have been earned under the Corporation's retirement plans if employment had continued for three years (in the case of Mr. Hudson, one year) following the date of termination, (b) participation in the life, disability, accident and health insurance plans of the Corporation for a three-year (in the case of Mr. Hudson, one-year) period except to the extent such benefits are provided by a subsequent employer and (c) a payment to compensate for the additional taxes, if any, payable on the benefits received under the severance agreements and any other benefits contingent on a change in control as a result of the application of the excise tax associated with Section 280G of the Internal Revenue Code. In addition, the pension plan arrangements for the Corporation's executive officers and the terms of the Corporation's stock options and restricted stock provide for vesting upon a change in control.

Robert D. Fagan served as Chairman, President and Chief Executive Officer of the Corporation until July 6, 2004. Upon termination of employment, pursuant to the terms of his January 28, 2003 severance agreement, Mr. Fagan received a lump-sum payment representing two times the sum of his annual salary and the greater of his targeted annual incentive award as of the date of termination and the most recent annual incentive award paid to him preceding the date of termination. Also, Mr. Fagan's unvested time-based restricted stock and his stock options immediately vested (with continued exercisability of the stock options until the expiration of the original option term), and the performance period for all performance-based restricted stock previously issued immediately ended and the corresponding number of shares (after performance measurement) vested. Mr. Fagan became entitled to continuation of life, disability, accident and health insurance benefits for 24 months. In addition, he received a lump-sum payment equal to the amount he would have earned under the Corporation's tax-qualified retirement plan and its supplemental retirement and excess benefit plans (offset by benefits under these plans) calculated as if he were fully vested under those plans, had continued to be a participant in those plans for 24 additional months, and had accumulated 24 additional months of compensation (taking into account the cash severance payments described above). Mr. Fagan is subject to a two-year noncompetition agreement which also prohibits him from soliciting customers, influencing other employees of the Corporation to terminate their employment, or influencing business partners to adversely alter their relations with the Corporation.

## *Ratification of Appointment of Auditor*

The Audit Committee has appointed the firm of PricewaterhouseCoopers LLP as the Corporation's independent auditor for 2005. Although action by the shareholders is not required, the Audit Committee believes that it is appropriate to seek shareholder ratification of this appointment in light of the critical role played by the independent auditor.

Representatives of PricewaterhouseCoopers LLP are expected to be present at the Annual Meeting of Shareholders and to be available to respond to appropriate questions. They will also have the opportunity to make a statement if they desire.

**The Board of Directors recommends a vote FOR the ratification of the action taken by the Audit Committee appointing PricewaterhouseCoopers LLP as the Corporation's independent auditor to conduct the annual audit of the financial statements for the fiscal year ending December 31, 2005.**

## *Audit Committee Report*

The Audit Committee is composed of four directors, each of whom is independent as defined by applicable New York Stock Exchange listing standards. The Committee assists the Board of Directors in overseeing (a) the integrity of the financial statements of the Corporation, (b) the annual independent audit process, (c) the Corporation's systems of internal control over financial reporting and disclosure controls and procedures, (d) the independence and performance of the Corporation's outside auditor and (e) the Corporation's compliance with legal and regulatory requirements. The Committee operates under a written charter adopted by the Board, a copy of which can be found on the Investor Relations page of the Corporation's website, www.tecoenergy.com.

In the course of its oversight of the Corporation's financial reporting process, the Committee has:

1. Reviewed and discussed with management the Corporation's audited financial statements, including Management's Discussion and Analysis, for the fiscal year ended December 31, 2004;
2. Discussed with PricewaterhouseCoopers LLP, the Corporation's independent auditor, the matters required to be discussed by Statement on Auditing Standards No. 61, Communication with Audit Committees, as amended, and Public Company Accounting Oversight Board Auditing Standard No. 2, An Audit of Internal Control Over Financial Reporting Performed in Conjunction with an Audit of Financial Statements; and
3. Received the written disclosures and the letter from PricewaterhouseCoopers LLP required by Independence Standards Board Standard No. 1, Independence Discussions with Audit Committees, discussed with PricewaterhouseCoopers LLP its independence and considered whether the provision of nonaudit services by PricewaterhouseCoopers LLP is compatible with maintaining its independence.

Based on the foregoing review and discussions, the Committee has recommended to the Board of Directors that the audited financial statements be included in the Corporation's Annual Report on Form 10-K for the year ended December 31, 2004 for filing with the Securities and Exchange Commission.

By the Audit Committee,
J. Thomas Touchton (Chairman)
James L. Ferman, Jr.
Tom L. Rankin
Paul L. Whiting

## *Independent Public Accountants*

**Audit and Non-Audit Fees**

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers LLP for the audit of the Corporation's annual financial statements for the years ended December 31, 2004 and December 31, 2003, and fees billed for other services rendered by PricewaterhouseCoopers LLP during these periods.

| | | *2004* | | *2003* |
|---|---|---|---|---|
| Audit fees | | $ 2,998,000 | | $1,456,500 |
| Sarbanes-Oxley fees | 1,403,000 | | 0 | |
| Audit-related fees | | 150,000 | | 178,000 |
| Tax fees | | 45,000 | | 42,401 |
| Tax compliance fees | 45,000 | | 37,119 | |
| Tax planning fees | 0 | | 5,282 | |
| All other fees | | 10,000 | | 14,573 |
| Total | | $ 3,203,000 | | $1,691,474 |

*Audit fees* consisted of fees for professional services performed for the audit of the Corporation's annual financial statements, including management's assessment of the Corporation's internal controls over financial reporting, and review of financial statements included in the Corporation's 10-Q filings, services that are normally provided in connection with statutory and regulatory filings or engagements and reviews related to debt and equity issuance and SEC filings.

*Audit-related fees* consisted of fees for assurance and related services that are reasonably related to the performance of the audit or review of the Corporation's financial statements, principally for the audit of benefit plans and consultations with the Corporation's management as to the accounting or disclosure treatment of transactions or events and/or the actual or potential impact of final or proposed rules, standards or interpretations by the SEC, FASB or other regulatory or standard-setting bodies.

*Tax fees* consisted of tax compliance fees for tax return review and income tax provision review; and tax planning fees, including tax audit advice.

*All other fees* consisted of fees for other permissible work performed by PricewaterhouseCoopers LLP, including fees for accounting advice related to specific transactions, regulatory accounting advice and other miscellaneous services.

All services rendered by PricewaterhouseCoopers LLP are permissible under applicable laws and regulations, and are pre-approved by the Audit Committee in order to assure that the provision of such services does not impair the auditor's independence.

**Audit Committee Pre-Approval Policy**

The Audit Committee has adopted a specific policy for pre-approval of services to be provided by the Corporation's independent auditor. Under the policy, in addition to the annual audit engagement terms and fees, the Audit Committee pre-approves specific types of audit, audit-related, tax and non-audit services to be performed by the independent auditor throughout the year, as well as fee ranges for each specific service, based on the Audit Committee's determination that the provision of the services would not be likely to impair the auditor's independence. Unless a type of service to be provided by the independent auditor has received general pre-approval, it will require specific pre-approval by the Audit Committee. Any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee. The pre-approval is effective for 12 months from the date of pre-approval. The policy permits the Audit Committee to delegate pre-approval authority to one or more of its members to ensure prompt handling of unexpected matters, with such delegated pre-approvals to be reported to the Audit Committee at its next meeting. The policy also contains a list of prohibited non-audit services and requires that the independent auditor ensure that all audit and non-audit services provided to the Corporation have been pre-approved by the Audit Committee.

## *Section 16(a) Beneficial Ownership Reporting Compliance*

The Corporation's executive officers and directors are required under Section 16(a) of the Securities Exchange Act of 1934 (the "Exchange Act") to file reports of ownership and changes in ownership with the Securities and Exchange Commission and the New York Stock Exchange. Copies of those reports must also be furnished to the Corporation.

Based solely on a review of the copies of reports furnished to the Corporation with respect to 2004 and written representations that no other reports were required, the Corporation believes that the executive officers and directors of the Corporation have complied in a timely manner with all applicable Section 16(a) filing requirements except that one executive officer, Sheila M. McDevitt, filed one late report.

## *Shareholder Proposals*

Proposals of shareholders intended to be presented pursuant to Rule 14a-8 under the Exchange Act for inclusion in the Corporation's proxy materials relating to the Annual Meeting of Shareholders in 2006 must be received on or before November 16, 2005. In order for a shareholder proposal made outside of Rule 14a-8 under the Exchange Act to be considered "timely" within the meaning of Rule 14a-4(c) of the Exchange Act, such proposal must be received by the Corporation not later than January 27, 2006. Any such proposals should be sent to: Corporate Secretary, TECO Energy, Inc., P. O. Box 111, Tampa, Florida 33601.

## *Advance Notice Provisions for Shareholder Proposals and Nominations*

The Bylaws of the Corporation provide that in order for a shareholder to bring business before or propose director nominations at an annual meeting, the shareholder must give written notice to the Secretary of the Corporation not less than 90 days nor more than 120 days in advance of the anniversary date of the immediately preceding annual meeting of shareholders. The notice must contain specified information about the proposed business or each nominee and the shareholder making the proposal or nomination. If the annual meeting is scheduled for a date that is not within 30 days before or after such anniversary date, the notice given by the shareholder must be received no later than the tenth day following the day on which the notice of such annual meeting date was mailed or public disclosure of the date of such annual meeting was made, whichever first occurs.

## *Solicitation of Proxies*

In addition to the solicitation of proxies by mail, proxies may be solicited by telephone, facsimile or in person by regular employees of the Corporation. The Corporation has also retained Morrow & Co., Inc. to assist in the solicitation of proxies for a fee of $7,500 plus out-of-pocket expenses. All expenses of this solicitation, including the cost of preparing and mailing this proxy statement, and the reimbursement of brokerage houses and other nominees for their reasonable expenses in forwarding proxy material to beneficial owners of stock, will be paid by the Corporation.

## *Householding of Annual Meeting Materials*

Some banks, brokers and other nominee record holders may be "householding" the Corporation's proxy statements and annual reports. This means that only one copy of the proxy statement and annual report to shareholders may have been sent to multiple shareholders in one household. The Corporation will promptly deliver a separate copy of either document to shareholders who call or write the Corporation at the following address or telephone number: TECO Energy, Inc., P. O. Box 111, Tampa, Florida 33601, Attn: Investor Relations, telephone: (813) 228-1111. Shareholders wishing to receive separate copies of the proxy statement or annual report to shareholders in the future should contact their bank, broker or other nominee record holder or ADP Investor Communications Services at 1-800-542-1061.

## *Other Matters*

The Board of Directors does not know of any business to be presented at the meeting other than the matters described in this proxy statement. If other business is properly presented for consideration at the meeting, the enclosed proxy authorizes the persons named therein to vote the shares in their discretion.

Dated: March 16, 2005

## Appendix A

The Board shall be comprised of a majority of directors who qualify as independent directors under the listing standards of the New York Stock Exchange and applicable law ("Independent Directors"). The Board shall review at least annually the relationship that each director has with the Company. Only those directors who the Board affirmatively determines have no relationship with the Company that would impair their independent judgment will be considered Independent Directors. The Board has established the following guidelines to assist in making that determination:

1. A director shall not be independent if, within the preceding three years: (i) the director was employed by the Company; (ii) an immediate family member of the director was employed by the Company as an executive officer; (iii) the director or an immediate family member of the director received more than $100,000 in direct compensation from the Company, other than director fees, pension, or other deferred compensation for prior service in any 12-month period; or (iv) a Company executive officer was on the compensation committee of a company which during that same time period employed the director, or which employed an immediate family member of the director, as an executive officer.

2. A director shall not be independent if (i) the director is a current employee or partner of the Company's independent or internal auditor; (ii) an immediate family member of the director is a current partner, or an employee who participates in the audit, assurance, or tax compliance practices, of the Company's independent or internal auditor; or (iii) the director or an immediate family member was a partner or an employee of the independent auditor and personally worked on the Company's audit within the last three years.

3. The following business or charitable relationships, based on the last completed fiscal year, shall not be considered to be material relationships that would impair a director's independence: (i) if a director is an employee, or if the immediate family member of the director is an executive officer, of another company that does business with the Company and the annual sales to, or purchases from, the Company are less than the greater of $1 million or one percent of the consolidated annual gross revenues of the company for which he or she serves as an executive officer or employee; (ii) if a director is an executive officer of another company which is indebted to the Company, or to which the Company is indebted, and the total amount of either company's indebtedness to the other is less than one percent of the total consolidated assets of the company for which he or she serves as an executive officer; (iii) if a director is an executive officer of a charitable organization, and the Company's discretionary charitable contributions to the organization are less than $1 million or one percent of that organization's total annual charitable receipts; and (iv) if a director serves as a director or trustee of a charitable organization, and the Company's discretionary annual charitable contributions to the organization do not exceed the greater of $200,000 or 5% of that organization's total annual charitable receipts. (Any automatic matching of employee charitable contributions will not be included in the amount of the Company's contributions for the purpose of items (iii) and (iv).) Items (iii) and (iv) above recognize the Board's view that its members should not avoid volunteering as directors or trustees of charitable organizations and that the Company should not cease ordinary course contributions to organizations for which a director has volunteered.

4. For relationships the character of which are not included in the categories in paragraphs 1-3 above, the determination of whether the relationship is material or not, and therefore whether the director would be independent or not, shall be made by the directors who satisfy the independence guidelines set forth in paragraphs 1-3 above.

5. The Board shall annually review all business and charitable relationships of directors, and whether directors meet these categorical independence tests shall be made public annually. The Company shall make appropriate disclosure of the basis for any Board determination that a relationship was immaterial despite the fact that it did not meet the categorical standards of immateriality in paragraph 3 above.

## *TECO Energy Executive Officers*

| | |
|---|---|
| Sherrill W. Hudson | Chairman of the Board and Chief Executive Officer |
| Charles R. Black | President, Tampa Electric |
| William N. Cantrell | President, Peoples Gas System |
| Clinton E. Childress | Senior Vice President – Corporate Services and Chief Human Resources Officer |
| Gordon L. Gillette | Executive Vice President and Chief Financial Officer |
| Sal Litrico | President, TECO Transport |
| Sheila M. McDevitt | Senior Vice President – General Counsel and Chief Legal Officer |
| John B. Ramil | President and Chief Operating Officer |
| J.J. Shackleford | President, TECO Coal |

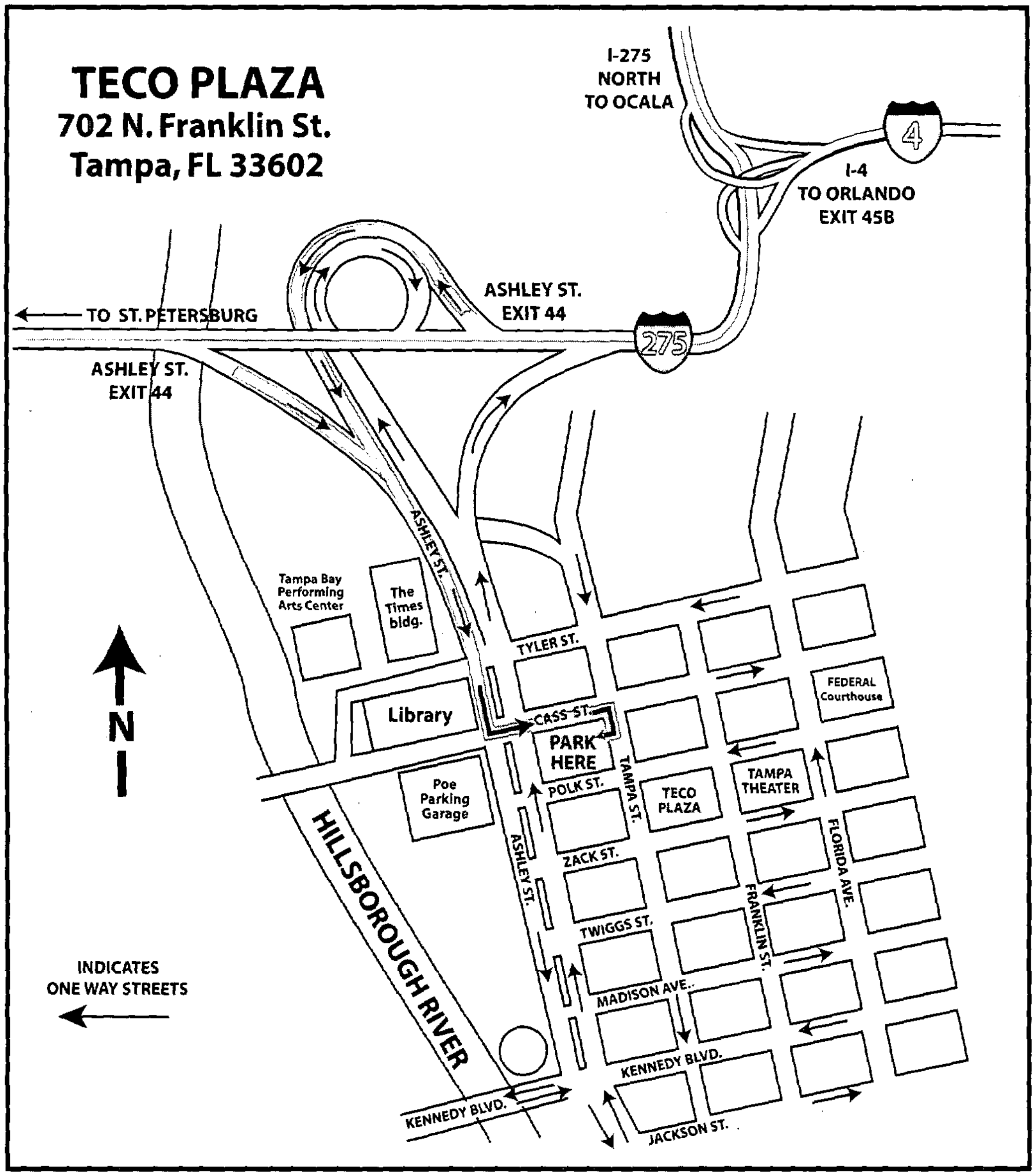
## *TECO Energy Staff Officers*

| | |
|---|---|
| Charles A. Attal III | Vice President – Deputy General Counsel |
| Phil L. Barringer | Vice President – Controller of Operations |
| Paul R. Bogenrieder | Vice President – Energy Risk Management |
| Deirdre A. Brown | Vice President – Regulatory Affairs |
| Sandra W. Callahan | Vice President – Treasury and Risk Management (Treasurer) |
| R. Bruce Christmas | Vice President – Fuels Management |
| Charles O. Hinson III | Vice President – State Government Affairs |
| Burnis L. Kilpatrick, Jr. | Corporate Compliance Officer |
| Karen M. Mincey | Vice President – Information Technology and Chief Information Officer |
| Michael R. Schuyler | Vice President – Wholesale Power |
| Shirley M. Payne | Vice President – Corporate Accounting and Tax (Chief Accounting Officer) |
| David E. Schwartz | Vice President – Assistant General Counsel and Corporate Secretary |
| Janet L. Sena | Vice President – Federal Affairs |

## *Board of Directors*

| | |
|---|---|
| Sherrill W. Hudson(3) | Chairman of the Board and Chief Executive Officer, TECO Energy, Inc., Tampa, Florida |
| DuBose Ausley(3) | Attorney and former Chairman, Ausley & McMullen (attorneys), Tallahassee, Florida |
| Sara L. Baldwin(2)(4) | Private Investor, Tampa, Florida |
| James L. Ferman, Jr.(1)(4) | President, Ferman Motor Car Company, Inc. (automobile dealerships), Tampa, Florida |
| Luis Guinot, Jr.(2) | Attorney and former Equity Partner, Shapiro, Sher, Guinot & Sandler, P.A. (attorneys), Washington, D.C., and former United States Ambassador to the Republic of Costa Rica |
| Tom L. Rankin(1)(3) | Independent Investment Manager, Tampa, Florida, former Chief Executive Officer, Lykes Energy, Inc. (the former holding company for Peoples Gas System) |
| William D. Rockford(3) | President, Primary Energy Holdings LLC (power generation), Oak Brook, Illinois, former Managing Director, Chase Securities Inc. (financial services), New York, New York |
| William P. Sovey(2)(4) | Former Chairman of the Board and Chief Executive Officer, Newell Rubbermaid, Inc. (consumer products), Freeport, Illinois |
| J. Thomas Touchton(1)(4) | President, The Witt-Touchton Company, LLC (private investment company), Tampa, Florida |
| James O. Welch, Jr.(2) | Former Vice Chairman, RJR Nabisco, Inc. and former Chairman, Nabisco Brands, Inc. (tobacco and food products), East Hanover, New Jersey |
| Paul L. Whiting (1) | President, Seabreeze Holdings, Inc. (consulting and private investments), Tampa, Florida, also Chairman of the Board, Sykes Enterprises, Incorporated, (outsourcing and consulting), Tampa, Florida |

(1) Member of the Audit Committee
(2) Member of the Compensation Committee
(3) Member of the Finance Committee
(4) Member of the Governance and Nominating Committee




**The Annual Meeting of Shareholders will be held on April 27, 2005, at 10:00 a.m.**

Directions to TECO Plaza from I-275 / I-4.

- From I-275 near downtown Tampa, take the **exit #44 Ashley St.** turnoff.
- Ashley Street will split to the right and to the left (under an overpass); take the right fork, toward The Times building; after the fork get in the left lane.
- Go through the first stoplight (Tyler Street).
- Turn left at the second stoplight (**Cass Street**) and get in the right lane.
- Turn right at the next stoplight (**Tampa Street**) and be prepared to turn right again into the parking lot.
- Make an immediate right into the parking lot once your've turned onto Tampa Street. There will be signage that says "**TECO Energy Shareholder Parking**". A parking attendent will be on duty to help you with parking questions.
- Once parked, walk across Tampa and Polk streets to TECO Plaza.

# Information for Investors

**Internet**
Current information about TECO Energy is on the Internet at **www.tecoenergy.com**

TECO Energy is listed on the New York Stock Exchange symbol: TE

**TECO Energy Offices**
702 N. Franklin Street
Tampa, FL 33602
813-228-1111
Fax 813-228-1670

**TECO Energy Shareholder Services**
813-228-1326
800-810-2032

**Auditors**
PricewaterhouseCoopers LLP
Tampa, FL

**Annual Meeting**
The Annual Meeting of Shareholders will be held on April 27, 2005, 10:00 a.m. at:
TECO Plaza
702 N. Franklin Street
Tampa, FL 33602

**Shareholder Inquiries**
Communication concerning transfer requirements, lost certificates, dividends and change of address should be directed to the Transfer Agent.
By phone: 1-800-650-9222
By e-mail: shareowners@bankofny.com

**Transfer Agent & Registrar**
The Bank of New York
Receive and Deliver Department
P.O. Box 11002
Church Street Station
New York, NY 10286
**www.stockbny.com**

**Dividend Reinvestment**
The company offers a Dividend Reinvestment and Common Stock Purchase Plan which allows common shareholders of record to purchase additional shares of common stock. All correspondence concerning this Plan should be directed to the Plan Agent:
The Bank of New York
Investment Services Department
P.O. Box 1958
Newark, NJ 07101-9774

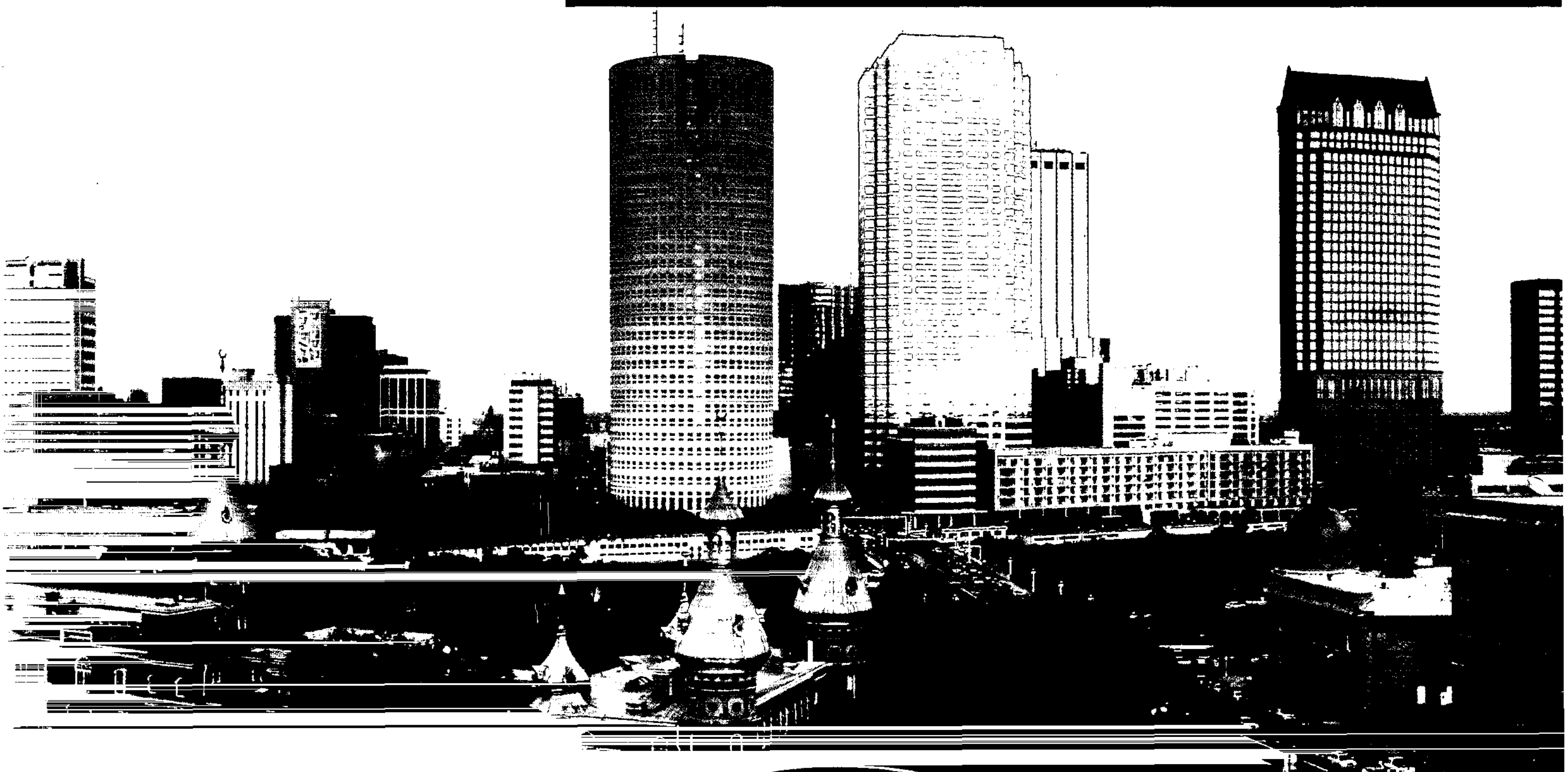
**Form 10-K Available**
TECO Energy's Annual Report on Form 10-K, which is filed with the Securities and Exchange Commission, is available on the Internet at **www.sec.gov** or through the Investor Relations page at **www.tecoenergy.com**. A printed copy is available to shareholders at no charge, upon a written request addressed to:
TECO Energy, Inc.
Investor Relations
P.O. Box 111
Tampa, FL 33601

**Analyst Contacts**
**Gordon L. Gillette,** Executive Vice President and Chief Financial Officer

**Sandra W. Callahan,** Vice President - Treasury and Risk Management

**Mark M. Kane,** Director - Investor Relations
813-228-1111

# LOOKING *forward*



# Dear Shareholders:

During the past year we continued to focus on our core businesses: the regulated utilities, Tampa Electric and Peoples Gas System, and our three established unregulated businesses, TECO Coal, TECO Transport and our Guatemalan operations. This focus guides all of our actions, and all of our business decisions. Some decisions and actions have been difficult, but all have been made with the goal of increasing shareholder value.

**"Looking ahead to 2005, we're expecting continued strong customer and energy sales growth..."**

### Our core businesses

In 2004, Tampa Electric and Peoples Gas continued to have strong customer and energy sales growth. Tampa Electric celebrated the dedication and full commercial operation of the repowered H.L. Culbreath Bayside Power Station, providing more than 1,700 megawatts of natural gas-fueled generation to serve the company's 625,000 customers. For their heroic response to the unprecedented hurricane season of 2004, the men and women of Tampa Electric were awarded the Edison Electric Institute's Emergency Response Award, an award shared with other utilities in the region.

TECO Coal has benefited from rising coal prices, and we expect that trend to continue to benefit that business. And, despite a challenging year, TECO Transport saw improvements in rates for river barge services and higher volumes at our terminal on the Mississippi River late in the year. We believe these events signal an improvement in the transportation markets. Our Guatemalan operations had an outstanding year, with continued customer and energy sales growth.

### Our discontinued businesses

We took a series of actions during the past year to reduce our exposure to the depressed merchant power sector. These actions included the sale of significant assets – like our interest in the Texas Independent Energy projects, and Frontera Power Station – and the announced sale of our Commonwealth Chesapeake Power Station. We also recorded large valuation adjustments on some of our power projects. I am confident these actions, though difficult, are the right things for our shareholders, our company and our people. We continue to make progress on the transfer of the two largest merchant holdings, Union and Gila River, and are expecting to complete the transfer of them to the lending group by mid-year.

While the actions we took to reduce our exposure to merchant power resulted in some very significant one-time charges to earnings, the tough decisions that we have made give us confidence in our future. Our core businesses have remained strong performers, and our results in 2004, excluding the valuation adjustments and write-offs, reflect the strength of these businesses.

### Our 2005 outlook

Looking ahead to 2005, we're expecting continued strong customer and energy sales growth at Tampa Electric and Peoples Gas. Tampa Electric is embarking on a $300-million environmental improvement project to further reduce nitrogen oxide emissions at its Big Bend Power Station, which will make the facility among the cleanest pulverized coal-fired plants in the nation.

At TECO Transport, we're already seeing improvements in waterborne transportation markets. At TECO Coal, 97 percent of our production is under contract for 2005, at prices 40 percent higher than prices in 2004. Our fully contracted power generation operations in Guatemala and our ownership interest in Guatemala's largest distribution utility are also expected to continue their strong operating performance and contributions to our bottom line.

### Our future

Not only have we reduced our exposure to the volatile merchant power sector, we have significantly improved TECO Energy's financial outlook as we begin 2005. Our cash and liquidity outlook has greatly improved. And though forecasts can be influenced by many factors, current longer-term expectations indicate that our cash position will allow us to retire most or all of the $680 million of TECO Energy corporate debt maturing in 2007, while at the same time meeting the capital spending needs of our core businesses and continuing our dividend.

With difficult decisions relating to our unregulated power investments behind us, our path forward is more clearly defined, and we expect that the actions we have taken will result in enhanced operational performance and shareholder value in 2005 and beyond.

As always, our efforts are driven by our desire to produce strong returns for our shareholders. On behalf of the Board of Directors, and all the men and women of TECO Energy, I want to express appreciation for the loyalty and continued support of our shareholders, customers and suppliers. We thank you for your continued interest and confidence in us.

Sincerely,

Sherrill W. Hudson

Sherrill W. Hudson
Chairman and CEO

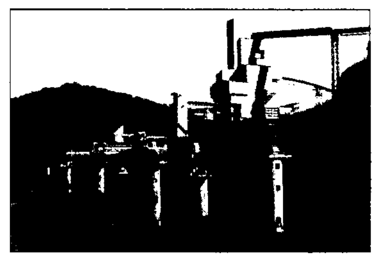
## TAMPA ELECTRIC

Tampa Electric is a regulated electric utility with approximately 4,400 megawatts of generating capacity. The company's service area covers 2,000 square miles in West Central Florida, including nearly all of Hillsborough County and parts of Polk, Pasco and Pinellas counties. More than 625,000 residential, commercial and industrial customers depend on Tampa Electric for reliable power.

## PEOPLES GAS SYSTEM

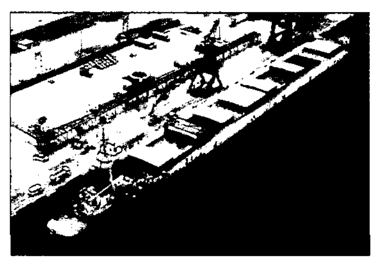
Peoples Gas is Florida's leading provider of regulated natural gas distribution services. With a presence in most of the state's major metropolitan areas, Peoples Gas brings reliable, environmentally friendly natural gas service to more than 314,000 residential and commercial customers.

## TECO COAL



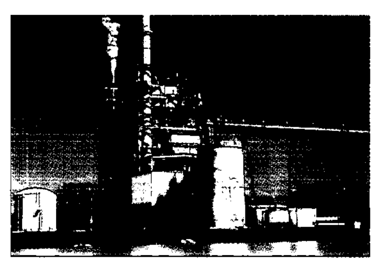
TECO Coal subsidiaries own and operate low-sulfur coal mines, synthetic fuel production facilities and coal preparation facilities in Kentucky and Virginia. These companies mine, process and ship more than nine million tons of conventional coal and synthetic fuel annually to the U.S. and European steel industry, as well as domestic utilities and other industrial customers. A TECO Coal subsidiary benefits from Section 29 tax credits associated with the sale of most of its ownership interests in its synthetic fuel production facilities and the sale of the synfuel product.

## TECO TRANSPORT



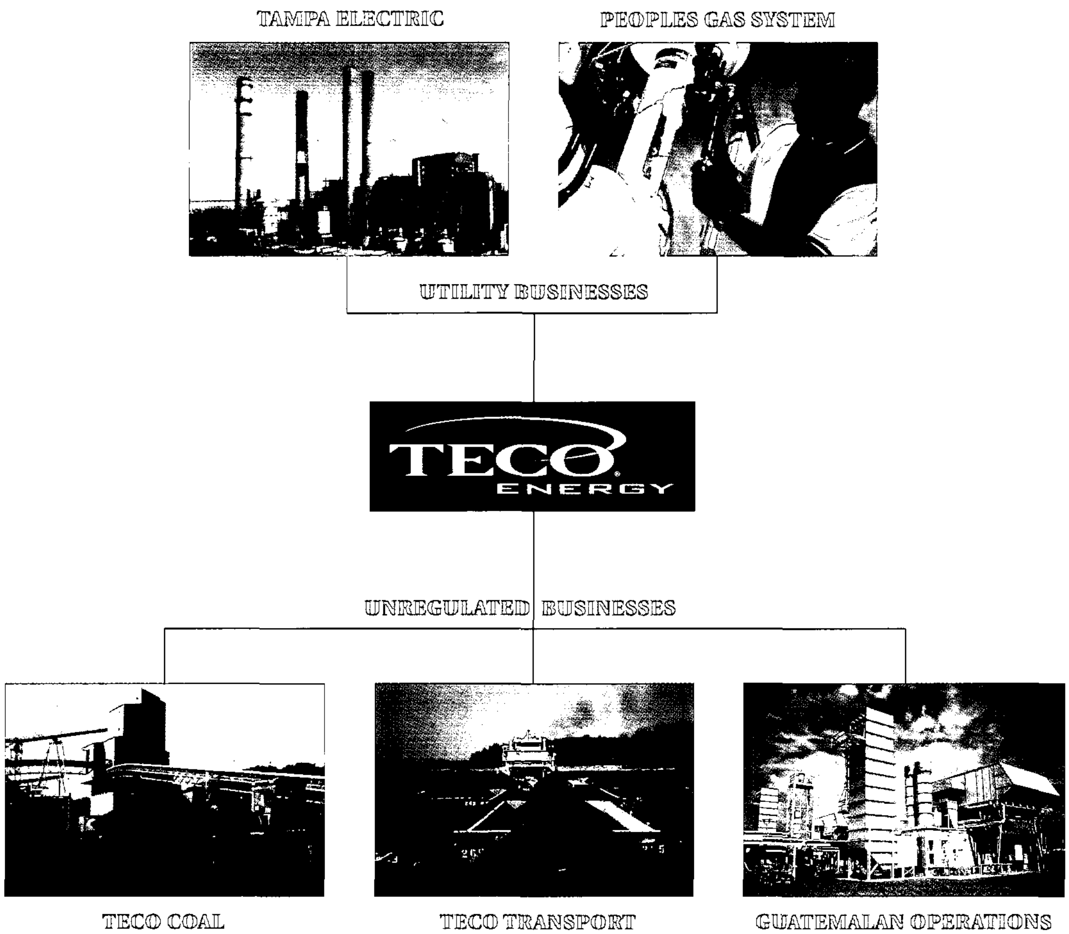
A marine transportation business consisting of three major subsidiaries, TECO Transport operates a U.S.-flag oceangoing fleet, a river barge fleet on the U.S. inland waterways, and a dry-bulk commodity deep-water transfer and storage terminal. TECO Transport moves coal, phosphate, grain and other bulk commodities domestically and internationally.

## GUATEMALAN OPERATIONS



TECO Energy subsidiaries also own two power plants with long-term power sales agreements in Guatemala: the 120-megawatt, coal-fired San José Power Station and the 78-megawatt, oil-fired Alborada Power Station (a peaking facility). The Guatemalan operations also include a 24 percent interest in EEGSA, Guatemala's largest distribution facility.

*TECO Energy, Inc. (NYSE:TE) is an energy-related holding company based in Tampa, Florida. In addition to the regulated operations of Tampa Electric and Peoples Gas System, TECO Energy businesses are engaged in coal and synthetic fuel production, river and ocean transportation, and unregulated power generation and distribution outside Florida. The company has major operations in Florida, the Southern U.S. and Guatemala.*




**Shareholder Inquiries:**
Communication concerning transfer requirements, lost certificates, dividends and change of address should be directed to the Transfer Agent.

**Transfer Agent & Registrar**
The Bank of New York
Receive and Deliver Department
P.O. Box 11002
Church Street Station
New York, NY 10286
800-650-9222
**www.stockbny.com**

TECO Energy Offices
TECO Plaza
702 N. Franklin Street
Tampa, FL 33602
813-228-1111
Fax 813-228-1670
**www.tecoenergy.com**

**Dividend Reinvestment**
The company offers a Dividend Reinvestment and Common Stock Purchase Plan which allows common shareholders of record to purchase additional shares of common stock. All correspondence concerning this Plan should be directed to the Plan Agent:
The Bank of New York
Investment Services Department
P.O. Box 1958
Newark, NJ 07101-9774

**Shareholder Contacts:**
**Gordon L. Gillette**, Executive Vice President - Chief Financial Officer

**Sandra W. Callahan**, Vice President - Treasury and Risk Management

**Mark M. Kane**, Director - Investor Relations

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