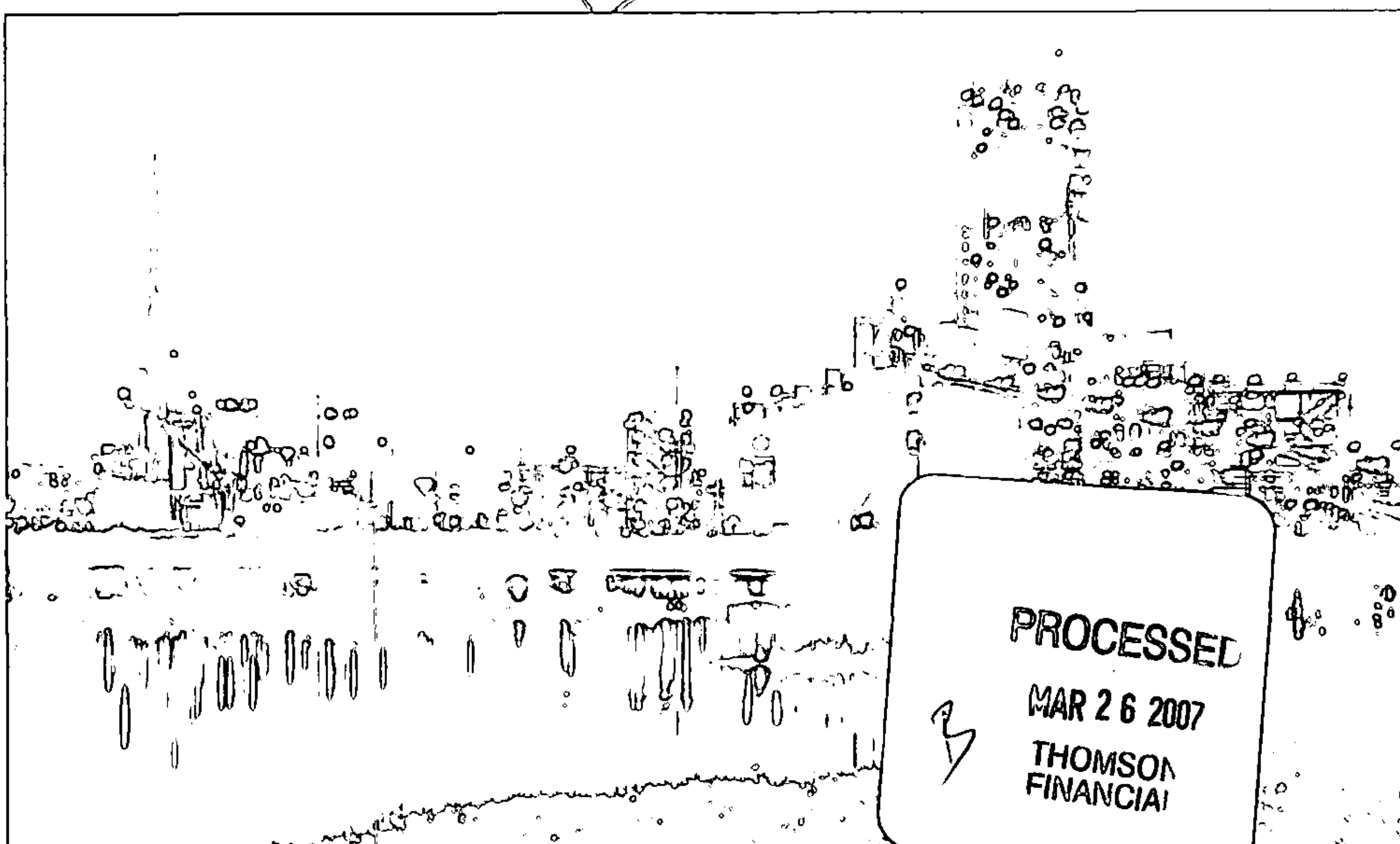
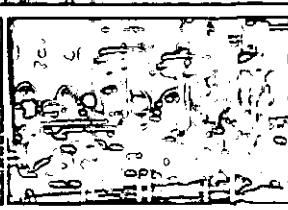
TECO ENERGY

2006 Annual Report and Proxy Statement

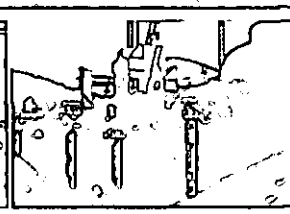
TAMPA ELECTRIC
Polk Power Station's Integrated Gasification Combined-Cycle (IGCC) Facility



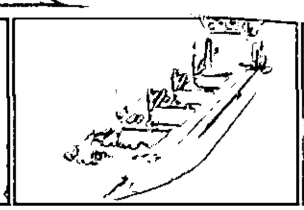
TAMPA ELECTRIC



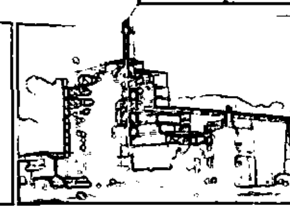
PEOPLES GAS



TECO COAL



TECO TRANSPORT

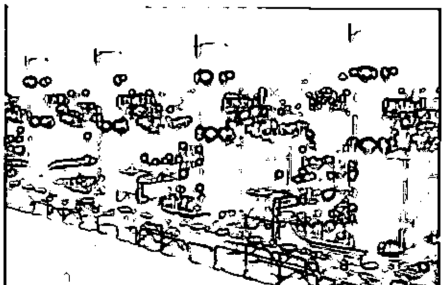


TECO GUATEMALA

Responsibly Serving Our Customers' Growing Energy Needs.

Our Businesses

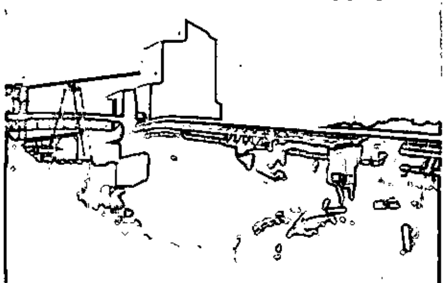
UTILITY BUSINESSES



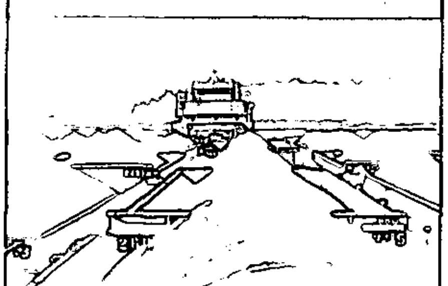
TAMPA ELECTRIC *is a regulated electric utility with almost 4,400 megawatts of generating capacity. The company's service area covers 2,000 square miles in West Central Florida, including nearly all of Hillsborough County and parts of Polk, Pasco and Pinellas counties. More than 660,000 residential, commercial and industrial customers depend on Tampa Electric for reliable power.*

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 330,000 residential, commercial and industrial customers.*

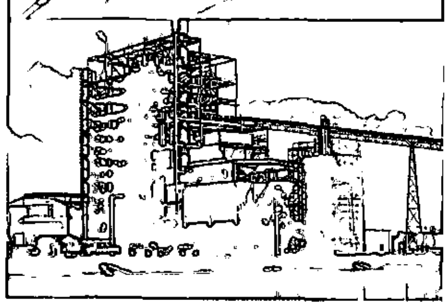
UNREGULATED BUSINESSES



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 industries, as well as domestic utilities and other industrial customers. Synthetic fuel produced by TECO Coal companies qualifies for federal tax credits for alternative fuels.*



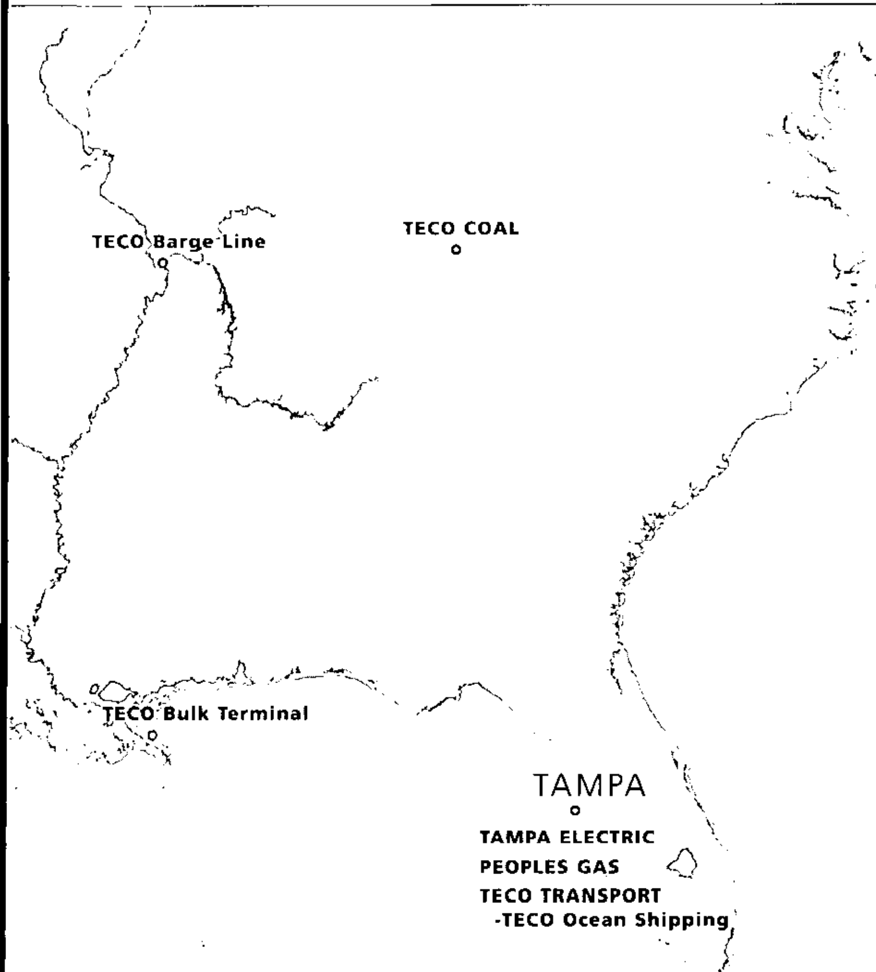
TECO TRANSPORT *is a marine transportation business consisting of three major subsidiaries, which operate a U.S.-flag oceangoing fleet, a towboat and river barge fleet on the U.S. inland waterways, and a dry-bulk commodity deep-water transfer and storage terminal. TECO Transport companies move coal, phosphate, grain and other dry bulk commodities domestically and internationally.*



TECO GUATEMALA *subsidiaries own two power plants with long-term power purchase agreements in Guatemala: the 120-megawatt, coal-fired San José Power Station and the 78-megawatt, oil-fired Alborada Power Station. TECO Guatemala's operations also include a 24 percent interest in EEGSA, Guatemala's largest electric distribution utility.*

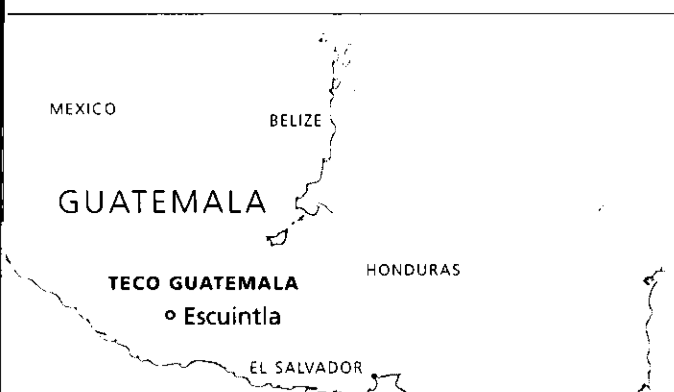
TECO ENERGY, INC. AND SUBSIDIARIES

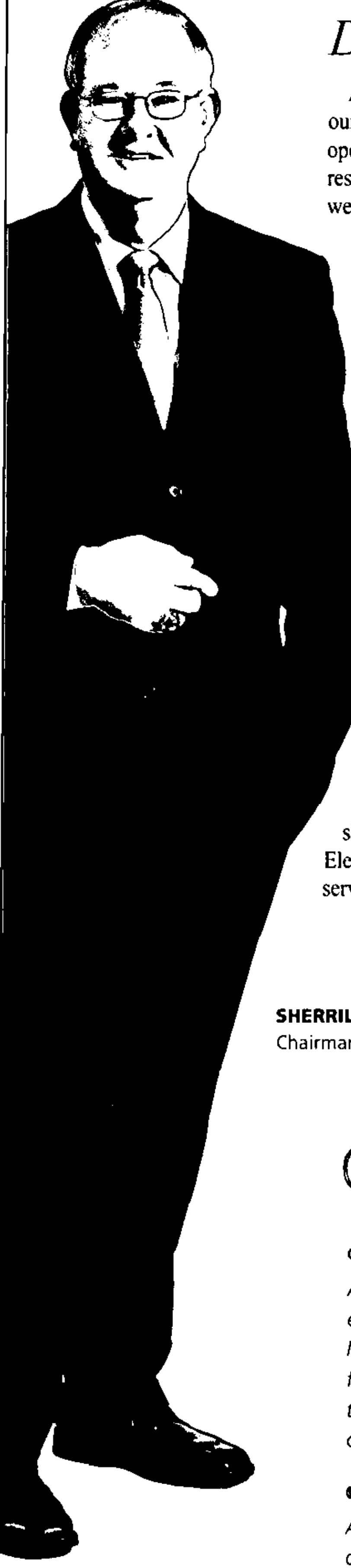
TECO Energy, Inc. (NYSE:TE) is an energy-related holding company based in Tampa, Florida. In addition to the regulated Florida operations of Tampa Electric and Peoples Gas, TECO Energy businesses are engaged in coal and synthetic fuel production in Kentucky; river and ocean transportation on the Mississippi River, the Gulf of Mexico and throughout the world; and power generation and distribution in Guatemala.



CONTENTS

TECO Energy Annual Report





Dear Shareholders,

As we reflect on 2006, I am very proud of what our team accomplished. We performed well both operationally and financially, despite challenges to our results related to synthetic fuel and less than favorable weather again this year.

In all of our activities, I am particularly pleased with how we held true to the five core values that define our corporate culture: safety, integrity, respect for others, achievement with a sense of urgency and customer service, as described at the bottom of this page.

2006 Accomplishments

Our financial focus in 2006 was the generation of cash for the retirement of debt. Despite record-high oil prices that reduced the tax credits associated with our synthetic fuel production business, we met our cash goals, including the repayment of $100 million in trust preferred securities, and we made an equity investment in Tampa Electric.

We were also able to meet our goal of accumulating cash in 2006 to be in a position to repay all of the 2007 parent-level debt maturities. We ended the year with almost $442 million of unrestricted cash on the balance sheet.

Our operational focus on our core utility businesses sharpened in 2006. Additional investment in Tampa Electric, for example, brought improvements in both service reliability and our customer service processes.

SHERRILL W. HUDSON
Chairman of the Board and Chief Executive Officer

Our Businesses

In February 2007, we announced that we are exploring the potential sale of or other strategic options for TECO Transport, our waterborne transportation business. We have retained Morgan Stanley to assist us in this process.

TECO Transport has been part of the TECO Energy family for many years, and has provided efficient, reliable and cost-effective transportation services to Tampa Electric over that time. But there are converging market dynamics that we cannot ignore.

Given the growth opportunities available to TECO Transport, we want to ensure that the business is best positioned to realize its potential in today's strong transportation market.

This mergers and acquisitions market for transportation companies could lead to good outcomes for all constituents and makes this an opportunity worth looking at, with the potential for good value for TECO Energy, growth for TECO Transport, and an excellent opportunity for an investor focused on marine transportation markets.

Infrastructure needs continue to be a prominent theme for our Tampa Electric business, and the utility industry as a whole.

With significant capital needs identified for the coming decade, Tampa Electric is focused on meeting regulatory requirements to "harden" its electric system, while making needed additions to the state's transmission system and addressing growing customer demand for power.

In the future, Tampa Electric expects to need a larger baseload generating unit to support its growing customer base. It published a request for proposals to meet its need for 600 megawatts of coal-fired generation starting in January 2013, which the company plans to either build or buy.

Our Culture

OUR PURPOSE

A commitment to inspiring trust, achieving excellence, providing environmental leadership and rising to any challenge we face, which will benefit our customers, team members and shareholders, and the communities we serve.

OUR VISION

A company where people want to work, an organization that is an asset to the community, and a business in which investors want to invest.

OUR VALUES

Safety

- *We emphasize a safe work environment and a culture of looking out for the safety and well-being of each other, our customers and our community.*
- *We believe the safety of life outweighs all other considerations.*

Integrity

- *We hold ourselves to the highest ethical behavior in all of our business activities, including legal, regulatory, financial, operational and environmental matters.*
- *We honor our commitments.*

If Tampa Electric constructs the unit, it will require significant capital investment, supported by equity from TECO Energy. Anticipating this potential capital investment, in addition to early repayment of debt at the parent level, has led us to explore the potential sale of TECO Transport.

If we are successful in obtaining good value for TECO Transport, we anticipate we would use the proceeds from the sale to accelerate our parent debt retirement plans.

As a result, we would have future cash available from operating activities to invest in Tampa Electric for generating capacity additions and other needs.

Peoples Gas System also has plans to expand its system to meet growing retail demand for environmentally friendly natural gas.

TECO Coal enjoyed strong coal markets again this year and effectively dealt with some tough mining conditions and operational interruptions when synthetic fuel production was temporarily idled due to high oil prices.

The company is making some incremental investments in new mining facilities that are expected to provide opportunities for long-term production gains.

TECO Transport continued to enjoy robust river and ocean shipping markets and its remarkable recovery from Hurricane Katrina in 2005, and experienced another year of success.

TECO Guatemala had another strong year, with excellent operations by its two generating facilities and good returns from its ownership interest in Guatemala's largest distribution utility.

2007 Strategic Focus

As we look forward to 2007 and beyond, we continue to focus on our utilities and their growth needs as our top priority, followed by growth in our other businesses.

TECO Energy continues its commitment to balance sheet improvement and debt retirement at the parent company level. We retired $100 million of trust preferred securities in December 2006, $57 million of junior subordinated notes of January 2007, and we have accumulated the cash to retire the $300 million of notes maturing in May 2007.

Longer term, we plan to retire additional debt and continue to improve our financial position.

We are targeting earnings growth of as much as 10 percent for 2007, excluding the benefits of the production of synthetic fuel.

As you will see going forward, we are working non-stop to return to a position of financial strength and our long-term pattern of earnings growth.

Why We're Here

Each of us at TECO Energy continues to work hard, every day, to meet the needs of our most important constituents: our shareholders, our customers and our team members.

Thank you for your continued support of our company.

Sincerely,

Sherrill W. Hudson

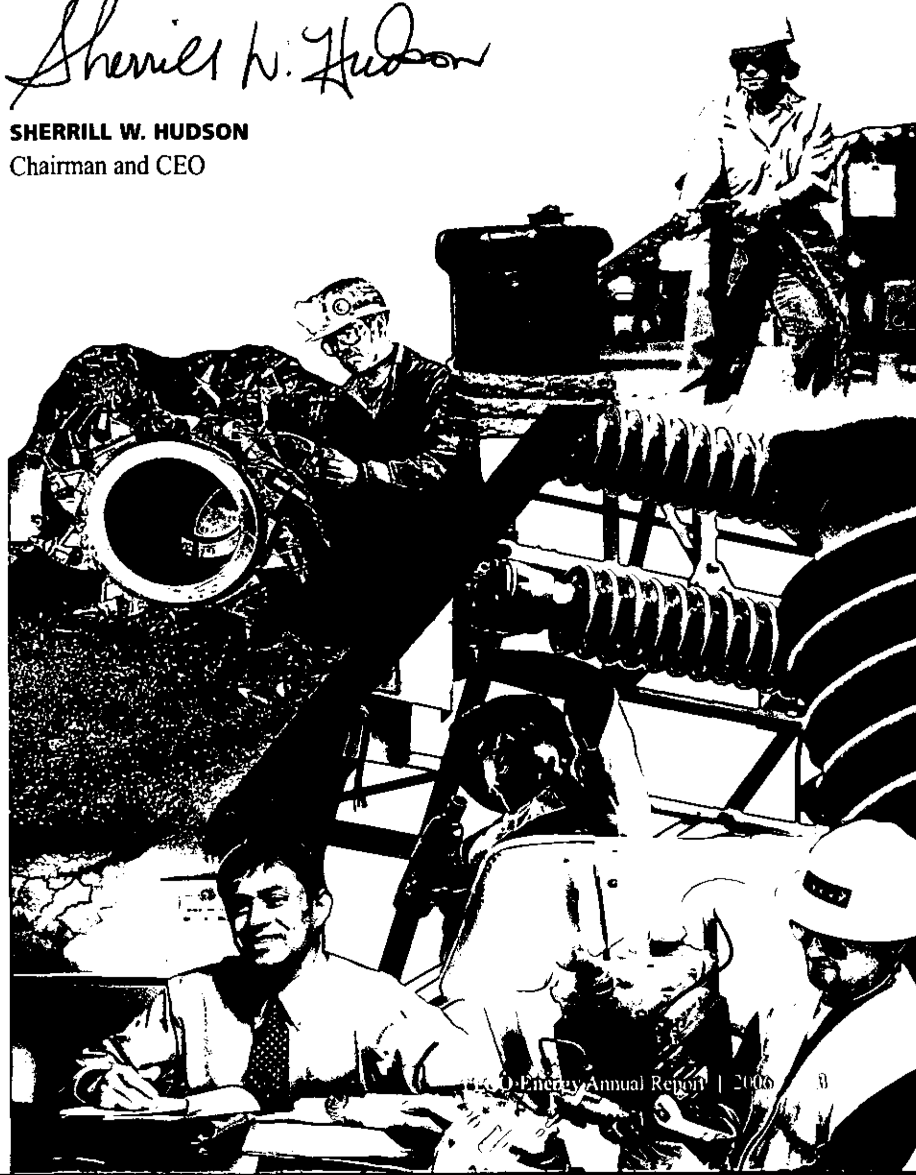
SHERRILL W. HUDSON
Chairman and CEO

OUR VALUES continued

Respect for Others
- *We value differences, development, teamwork, open communications and continuous learning.*
- *We treat all stakeholders, customers, team members, business partners and investors, fairly.*
- *We communicate openly and in a timely way with all stakeholders.*

Achievement With a Sense of Urgency
- *We work, as a team, with speed, sound judgment and diligence toward common goals.*
- *We support the business strategy and accept ownership and personal responsibility for our actions.*

Customer Service
- *We realize customers are why our organization exists.*
- *We treat them fairly and provide high-quality services.*



Tampa Electric

In 2006, Tampa Electric enjoyed strong customer growth, but revenues were again challenged by mild weather. In addition to continued work on environmental projects at Big Bend Power Station, the company celebrated the 10th Anniversary of Polk Power Station, recognized as the cleanest coal-fired power plant in North America.

Continued Growth, Weather Challenges

In 2006, Tampa Electric welcomed almost 18,000 new customers to its service territory, reflecting average customer growth of 2.8 percent.

Strong customer growth was offset again this year by mild weather, in addition to lower per-customer energy usage.

Factors influencing per-customer energy usage included weather, price elasticity and changes in building trends.

Milestone for Clean Coal Technology

In 2006, Tampa Electric's Integrated Gasification Combined-Cycle (IGCC) unit at Polk Power Station celebrated 10 years of commercial operation. Polk has been named the cleanest coal-fired power plant in North America by an independent Canadian research firm, after a review of more than 400 plants in Canada, the United States and Mexico.

Polk is also recognized as the world leader in the production of electricity from environmentally friendly synthesis gas or "syngas." The facility has generated more electricity using syngas in its ten years of operation than any other facility in the world.

In addition to Polk's contributions as an efficient and highly reliable resource in Tampa Electric's generating fleet, it is also a source of knowledge for dignitaries from around the world.

Each year, Polk hosts thousands of visitors seeking to learn more from the world leader in IGCC technology. Academicians, industry leaders and members of Congress have all been part of Polk's ever-growing guest book.

Environmental Upgrades Continue

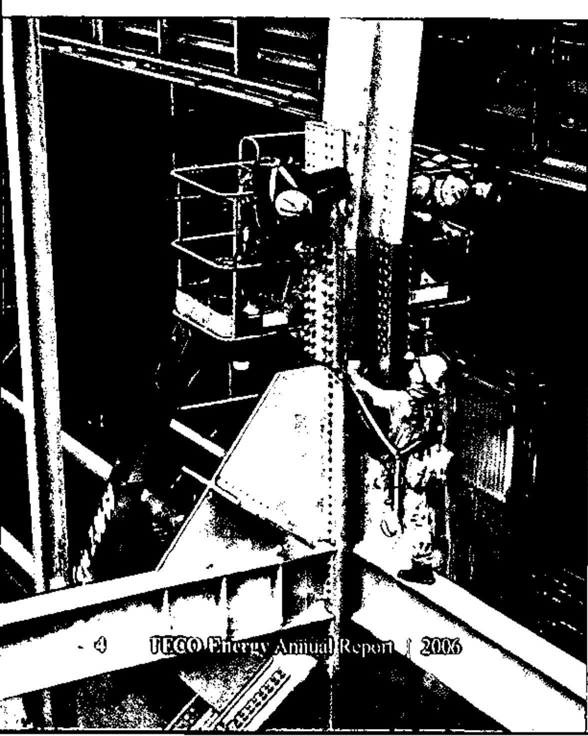
Tampa Electric team members continued work on the next major phase of the company's $1.5-billion, ten-year environmental improvement plan: the installation of best available control technology to reduce nitrogen oxides (NOx) emissions at the coal-fired Big Bend Power Station.

Selective catalytic reduction, or SCR, technology, functions like the catalytic converter on a car. The SCR unit takes NOx out of the gas stream of the coal-fired electric power generating plant, reducing pollution. When complete in 2010, the system will cut NOx by 75 percent on Unit 4 and more than 90 percent on Units 1-3.

Customer Service Advances

In 2005, Tampa Electric implemented a predictive dialing phone system to help manage safety, power restoration, bill collection and other communications in a single package.

The company's predictive dialer system was initially designed to generate automatic calls to company field workers after hours, letting them know where to report for power restoration work.

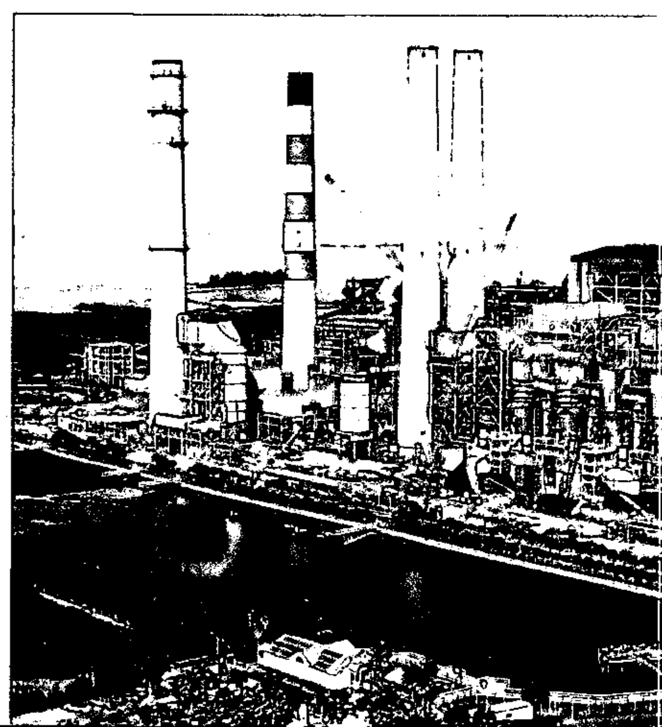


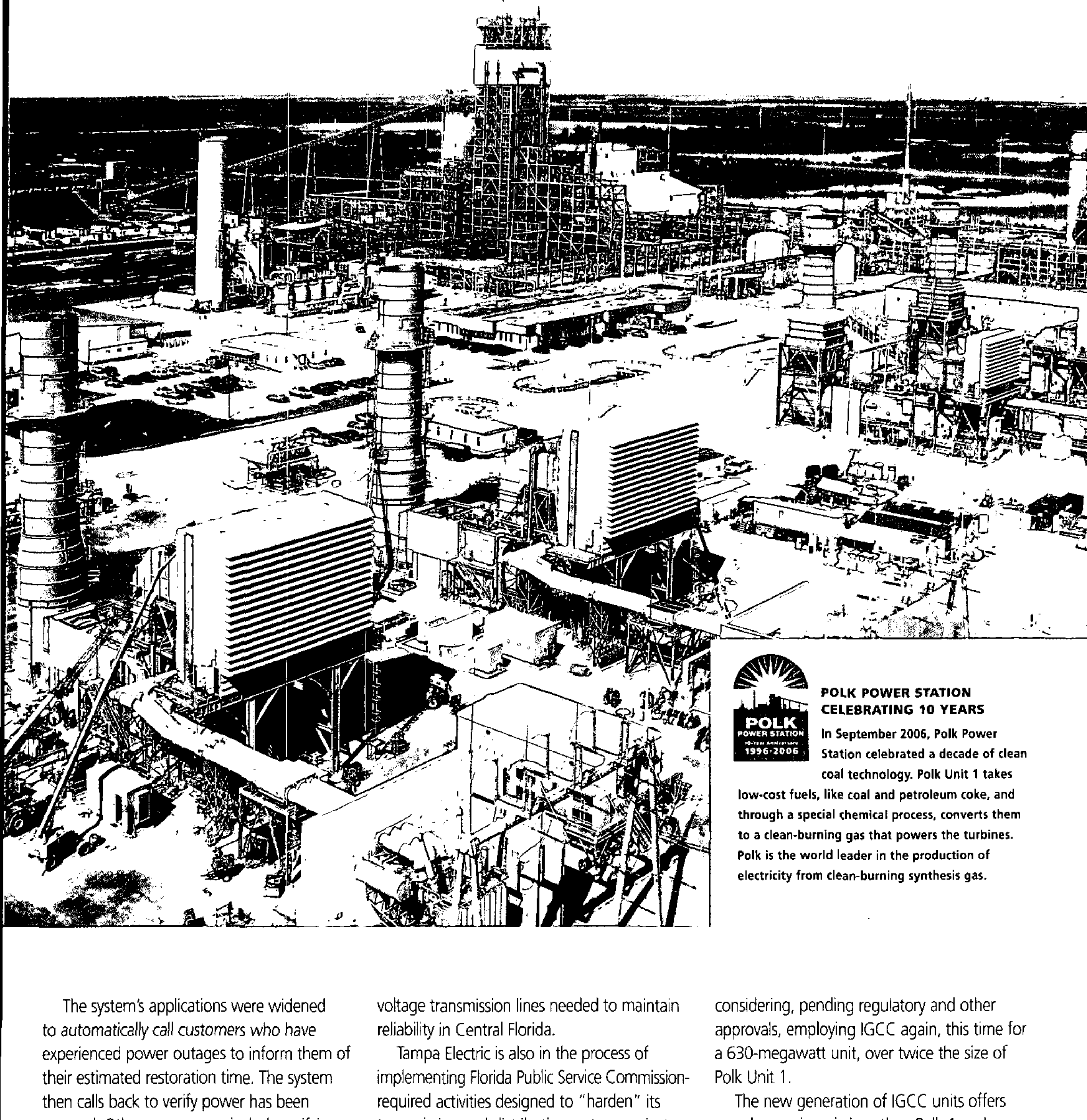
SCR PROJECT

Left: **Work continues on the installation of selective catalytic reduction technology at Tampa Electric's coal-fired Big Bend Power Station. The SCR project will reduce nitrogen oxides emissions significantly at Big Bend by 2010.**

BIG BEND POWER STATION

Right: **Big Bend provides more than 1,700 megawatts of coal-fired electricity to Tampa Electric customers. The responsible use of coal, an abundant and affordable fuel, is an important part of Tampa Electric's fuel diversity strategy.**





POLK POWER STATION CELEBRATING 10 YEARS

In September 2006, Polk Power Station celebrated a decade of clean coal technology. Polk Unit 1 takes low-cost fuels, like coal and petroleum coke, and through a special chemical process, converts them to a clean-burning gas that powers the turbines. Polk is the world leader in the production of electricity from clean-burning synthesis gas.

The system's applications were widened to automatically call customers who have experienced power outages to inform them of their estimated restoration time. The system then calls back to verify power has been restored. Other proven uses include verifying streetlight outage reports and contacting customers with missed electric service payments.

Growth and Expansion

The next decade is expected to be one of significant capital investment and growth for Tampa Electric.

On the energy delivery side of the business, there are additional capital needs. The company will be investing to build its share of the high voltage transmission lines needed to maintain reliability in Central Florida.

Tampa Electric is also in the process of implementing Florida Public Service Commission-required activities designed to "harden" its transmission and distribution system against storm damage.

Starting in early 2007, the company welcomes Polk Units 4 and 5, two natural gas-fueled peaking units with a capacity of 180 megawatts each.

The company has also announced plans for its next baseload unit, due to be in commercial operation by January 1, 2013. Building on its success at Polk Power Station, the company is considering, pending regulatory and other approvals, employing IGCC again, this time for a 630-megawatt unit, over twice the size of Polk Unit 1.

The new generation of IGCC units offers even lower air emissions than Polk 1 and the potential to capture or sequester carbon dioxide.

Recognizing Tampa Electric's potential for success with a new IGCC unit, in late 2006, the United States Department of Energy awarded the company $133.5 million in tax credits under a program to encourage the development of clean coal technologies.

Peoples Gas

In 2006, Peoples Gas enjoyed its 10th straight year of earnings growth, while the company invested in enhanced customer service and system growth to meet growing demand for environmentally friendly natural gas. The company continued to be recognized for its safety achievements.

Customer Growth and Improved Service

In 2006, the company's annual customer growth rate was 3.3 percent. Peoples Gas celebrated its tenth straight year of earnings growth.

Sharpening its dedication to customer service, the company is focused on serving customers faster and more accurately than ever before. A new Interactive Voice Response System was designed for use in the customer call center.

The new IVR, when installed in early 2007, will reduce wait times and provide customers with options that will significantly speed service delivery. In addition to the company's online bill payment service, customers will have the ability to view monthly and historical statements on the company's Web site.

System Investment and Expansion

As planned, Peoples Gas completed construction of a large gas supply line to enhance service to its largest customer, Jacksonville Electric Authority.

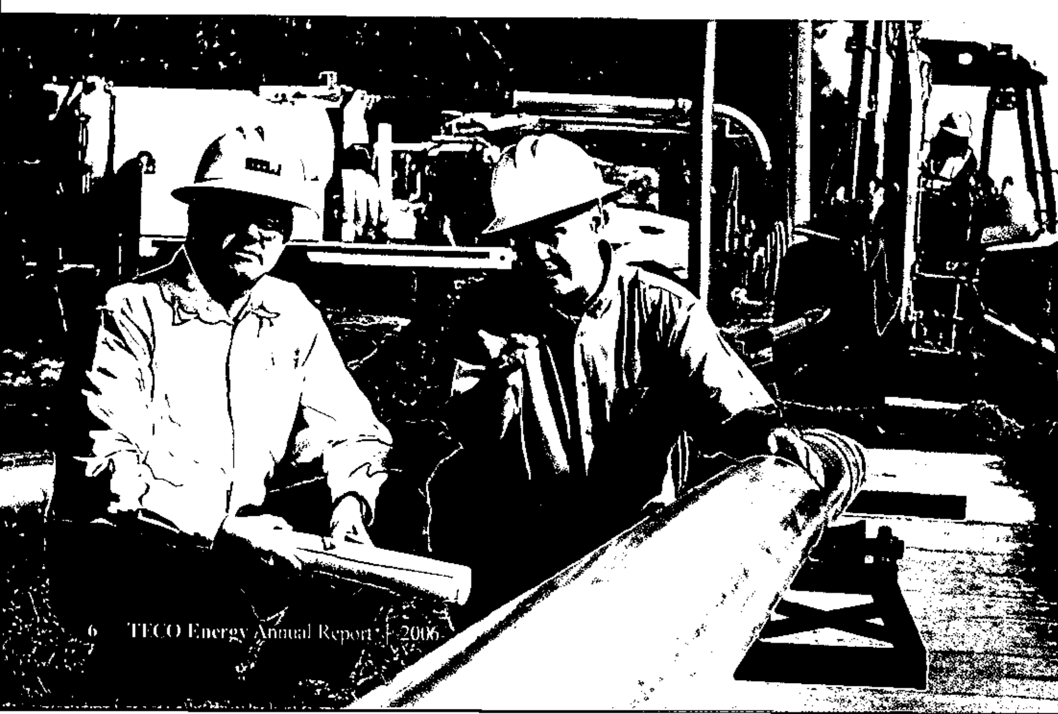
The company added four more counties to its service area last year. Pipelines were extended to provide natural gas in a number of additional areas, including a large section south of Ocala with new residential and commercial developments, as well as a major commercial boulevard in Broward County and the city of St. Augustine in St. Johns County.

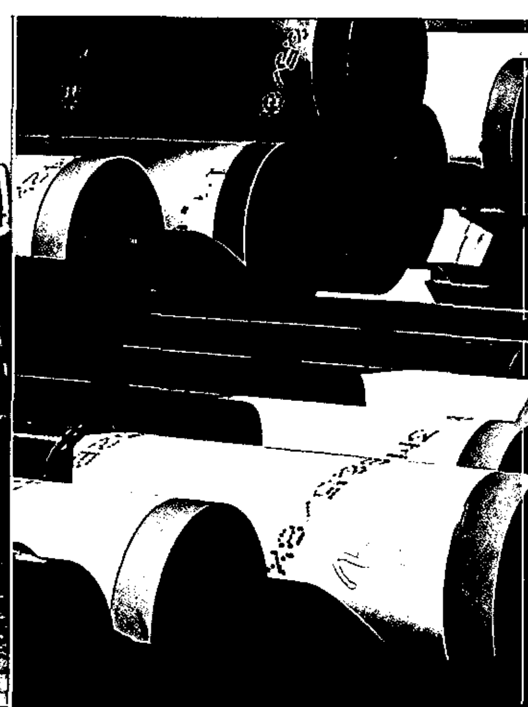
Peoples Gas received approval from the Florida Public Service Commission to modify its energy conservation programs. The approval allows enhanced incentive payments that could be applied to the purchase of new gas appliances in the residential market.

This change is neutral to the company's net income, but should facilitate new customer additions in the future, and helps existing customers save energy.

Safety Recognition

In 2006, the American Gas Association presented Peoples Gas with the Leader Accident Prevention Award for achieving a total OSHA recordable injuries and illness rate below the industry average.



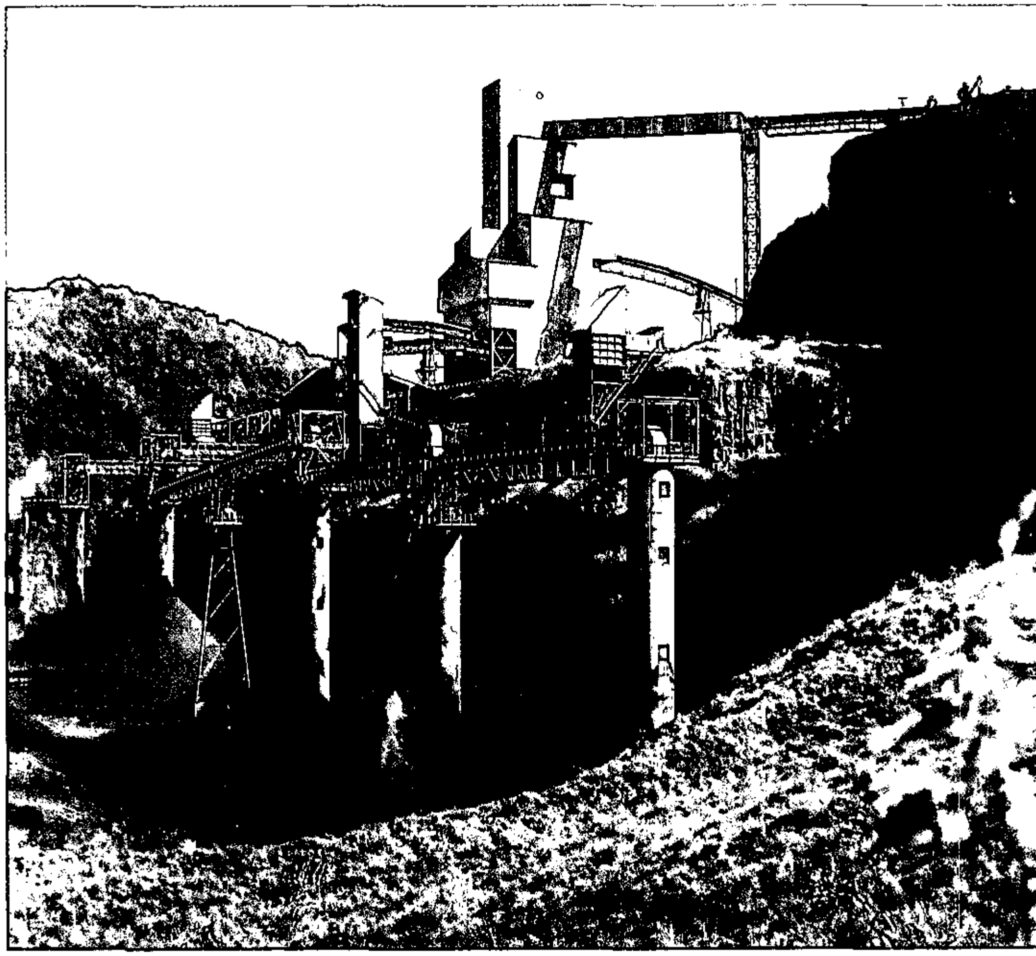


Below left: **PEOPLES GAS team members oversee installation of natural gas pipelines to serve the growing demand for natural gas in Northeast Florida.**

Below right: **Natural gas pipe ready for installation. Peoples Gas continued to experience strong customer growth in 2006, at a rate of more than 3 percent.**

TECO Coal

TECO Coal saw strong coal markets again in 2006, with higher prices. The company continues to invest in incremental growth and enhancements to its mine safety program.



Strong Markets

TECO Coal enjoyed strong coal markets again in 2006, with higher average net selling prices per ton across all products. The company has a majority of its production under contract for 2007.

The company temporarily idled its production of synthetic fuel during the summer of 2006, when high oil prices reduced the value of tax credits available for the production of it, adversely impacting the cash payments TECO Coal received from its synthetic fuel investors.

Team members effectively dealt with operational interruptions during this hiatus.

Incremental Growth

Although some expansion activities planned for 2007 were delayed due to a softening in the coal market, the company made investments in plant upgrades and lease acquisitions that are expected to provide long-term production gains.

In 2006, TECO Coal installed equipment to improve coal recovery from two coal preparation plants. The equipment is expected to add 50,000 tons of coal for the high-value metallurgical market and 100,000 tons of coal of high quality utility coal to the market in 2007.

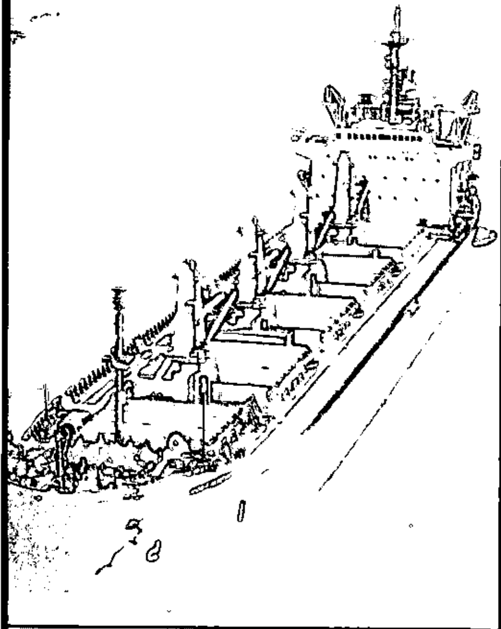
Mine Safety

TECO Coal made an additional investment in its already robust safety program to address new requirements at the federal and state levels.

The company recognizes its employees as its most valuable asset, and the company is absolutely committed to their safety. Programs such as the company's S.A.F.E. (Safety and Accountability For Everyone) program are designed to promote safe working practices, provide the best possible work environment and encourage compliance with all applicable regulations.

The company has received numerous awards for its safety, including the Joseph P. Holmes Safety Association safe mine award.

PREMIER ELKHORN, one of TECO Coal's main operations, is supplied by a number of both deep and strip mine operations. The operation's principal products include high quality steam coal for utilities, specialty stoker products for industrial uses, PCI coals for steel mills and coal used in other metallurgical industries.



TECO OCEAN SHIPPING
Strong transportation markets have created many opportunities for *TECO Transport companies*, including increased numbers of international voyages on vessels like the M/V Sheila McDevitt, pictured here.

TECO Transport

TECO Transport continued to enjoy strong river and ocean shipping markets during its remarkable recovery from Hurricane Katrina and experienced another year of success.

TECO Bulk Terminal

Team members at TECO Bulk Terminal completed permanent repairs to damage resulting from hurricanes Katrina and Rita by May 2006.

TECO Ocean Shipping

Demand for oceangoing dry bulk shipping remained strong due to good domestic and international markets. The company again participated in increased numbers of international voyages than it had in previous years, thanks to favorable market conditions.

TECO Ocean Shipping team members also achieved higher utilization of equipment, with more days spent operating on average than previous years.

TECO Barge Line

To take advantage of strong demand and good pricing in the river transportation business, TECO Barge Line brought 50 newly built barges on line starting in mid-2006, replacing older barges that were retired.

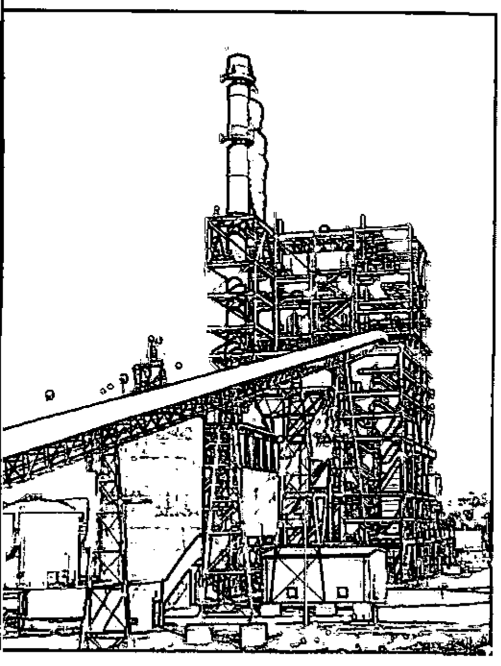
This reduces the average age of TECO Barge Line's fleet, and gives the business more operating flexibility to take advantage of strong rates.

Growth Opportunities

TECO Transport as a whole has enormous potential to grow and take advantage of strong transportation markets.

In early 2007, TECO Energy announced that it is exploring options to meet or exceed parent-level debt retirement commitments and to make additional investments in its principal business, Tampa Electric, to support that company's growing capital requirements.

These options include the sale of TECO Transport. The decision to explore this option is based on marine transportation market conditions that are right for the company to get good value for TECO Transport and for any new owner to obtain a high quality company with a dedicated operating team.



SAN JOSÉ POWER STATION and its sister facility, Alborada Power Station, are important parts of the Guatemalan energy infrastructure. TECO Guatemala also owns an interest in Guatemala's largest distribution utility, Emprésa Eléctrica de Guatemala, S.A.

TECO Guatemala

TECO Guatemala had a good year in 2006, producing strong earnings and cash flow and achieving results that exceeded the company's expectations.

The team also achieved lower-interest financing through renegotiation and lowered its property insurance expenses.

The company also met all of its operational targets. The generating stations operated extremely well, with an average of more than 95 percent availability at both, and excellent safety records.

TECO Guatemala's ownership interest in distribution assets at Emprésa Eléctrica de Guatemala, S.A. (EEGSA) continues to pay dividends, providing excellent income and continued growth. EEGSA performed better than expected in 2006.

In the TECO Energy tradition, TECO Guatemala continued to give back to its local communities. The company has built a 50-student school near the San José Power Station.

In addition, team members have donated funds for two classrooms to an elementary school near the Alborada Power Station, as well as school supplies and playground equipment.

Management's Discussion & Analysis

Table of Contents

This page left intentionally blank.

Management's Discussion & Analysis *of Financial Conditions & Results of Operations*

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. Such statements are based on our current expectations, and we do not undertake to update or revise such forward-looking statements. These forward-looking statements include references to our anticipated capital expenditures, liquidity and financing requirements, projected operating results, future transactions, and other plans. Important factors that could cause actual results to differ materially from those projected in these forward-looking statements are discussed under "Risk Factors."

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

We are a diversified energy-related holding company with five businesses consisting of regulated electric and gas utility operations in Florida and other operating companies engaged in coal mining and synthetic fuel production, waterborne transportation services and, in Guatemala, unregulated electric generation with long-term contracts and regulated electricity distribution.

Our regulated utility companies, Tampa Electric and Peoples Gas System (PGS) operate in the high-growth Florida market. Tampa Electric serves more than 661,000 retail customers in a 2,000 square mile service area in west central Florida and has electric generating plants with a winter peak generating capacity of 4,383 megawatts. PGS, Florida's largest regulated gas distribution utility, serves more than 332,000 residential, commercial, industrial and electric power generating customers in all of the major metropolitan areas of the state, with a total natural gas throughput of 1.3 billion therms in 2006.

Our other energy-related operating companies are TECO Coal, TECO Transport and TECO Guatemala. TECO Coal, through its subsidiaries, operates surface and underground mines and related coal processing facilities in eastern Kentucky, Tennessee and southwestern Virginia producing metallurgical-grade and high-quality steam coals. Sales in 2006 were 9.8 million tons, of which 5.3 million tons were sold as synthetic fuel. TECO Transport, our waterborne transportation company, through its subsidiaries, operates a fleet of inland river barges and towboats on the Ohio, Mississippi and Illinois rivers and their tributaries; a fleet of eight oceangoing tug-barge combination units and three ships that operate in the Gulf of Mexico and worldwide transporting dry-bulk cargos; and a dry-bulk storage and transfer terminal located on the Mississippi River southeast of New Orleans. TECO Guatemala, through its subsidiaries, owns a coal-fired generating facility and has a 96% ownership interest in an oil-fired peaking power generating plant, both under long-term contracts with a regulated distribution utility in Guatemala. It also has a 24% ownership interest in Guatemala's largest distribution utility.

Since 2003, our business strategy has been to focus on these five businesses and also to divest of our merchant power and unregulated energy services businesses, which was substantially completed in 2005. This strategy was implemented following a series of major investments in unregulated domestic power generation facilities outside of Florida, and other smaller unregulated energy service providers within Florida made during the years 2000 through 2003. These investments were made in anticipation of a movement toward competitive energy markets in Florida and other states. However, the wholesale power markets evolved in a manner that was much different than we expected at the time the investment decisions were made, and the independent power business changed dramatically. These changes reduced the prospects for the profitability of the investments in our unregulated domestic independent power generation facilities for several years to come, such that we decided to reduce the risk to cash flow and earnings from our involvement in the merchant power sector by divesting the assets (see the **TWG Merchant** section). In the exiting of the merchant power business, we sold assets at prices below those we paid and recorded large write-offs, and in the case of the large Union and Gila River power plants we wrote off our entire equity investment. We had issued significant amounts of debt at the TECO Energy parent level to fund portions of these investments, which negatively impacted our balance sheet and credit ratings.

As a result of our renewed focus on our utility operations and profitable unregulated businesses and the aggressive and successful execution of our plans to exit the merchant power business, our financial position has improved, our business risk profile has been reduced, and all three of the debt rating agencies moved their outlook on TECO Energy's and Tampa Electric's debt ratings from "negative" to "stable" in 2005. One of our goals, over time, is to return to an investment-grade credit rating at the parent level and to improve Tampa Electric's credit ratings through our actions to improve our cash flows, reduce debt and reduce business risk.

Our cash priorities are to reduce parent debt levels and to invest in Tampa Electric to support its capital needs associated with customer growth and environmental compliance. As part of our efforts to return to investment grade, in 2006, we announced plans to retire $500 million of TECO Energy parent-level debt beyond the retirement of the $357 million maturing in 2007 and the $200 million of 8.5% trust preferred securities (TruPS) retired in 2005 and 2006. We are now considering various options to meet or exceed our debt retirement goals, and to make additional investments in Tampa Electric to support its growing capital requirements (see the **Tampa Electric** and **Capital Expenditures** sections).

Given the growth opportunities available in water transportation, we want to ensure that TECO Transport is best positioned to realize its potential in today's strong marine transportation market. Among the alternatives we are considering to address our financial and business priorities is a review of the options for the long-term future of TECO Transport, including its sale.

The sale of TECO Transport is not a decision we take lightly, as it has a long history as a solid and profitable performer in our family of companies. However, the current strong market for transportation services and for transportation company mergers and acquisitions makes this an opportunity that we must consider, with the potential for good value to TECO Energy and growth for TECO Transport from an investor focused on marine transportation markets.

2006

In 2006, we remained focused on growing earnings and building our cash and liquidity position to enable us to grow our utility businesses and to further reduce TECO Energy parent debt. Our per-share results, excluding charges, gains and synthetic fuel results, improved over 2005 levels. Despite the reduced cash generation from the production of synthetic fuel due to high oil prices, our businesses provided strong cash generation, which allowed us to build a significant cash position. This allowed us to continue our accelerated efforts to reduce parent debt with the retirement of the remaining $100 million of our highest cost debt, the 8.5% TruPS due in 2041. We also made a planned $52 million cash equity contribution to Tampa Electric to support its higher capital expenditures as the construction of the two peaking units at the Polk Power Station and the selective catalytic reduction (SCR) equipment for nitrogen oxides (NO_x) control on the coal-fired units at the Big Bend Power Station continued, and we made a voluntary, previously unplanned $30 million contribution to the TECO Energy pension plan to accelerate improvement in the funded status of the plan. We also invested in additional facilities at TECO Coal to replace higher cost mines that are being idled and to increase production after 2007, if market conditions warrant it. Even after these actions, and despite reduced cash proceeds from investors in our synthetic fuel production facilities, we ended 2006 with over $400 million of cash available at the TECO Energy parent level.

Our earnings in 2006 reflected improved results at PGS and TECO Transport, the elimination of operating losses related to merchant power activities, and lower parent interest expense as a result of the early retirement of $380 million of 10.5% notes in June 2005 and the first $100 million of TruPS in late 2005. Tampa Electric continued to benefit from strong customer growth, but the planned increased spending on customer service enhancements, distribution system reliability, and reliability and capacity factor improvements on its coal-fired generating units offset higher base revenues. Results also reflected the impact of the temporary idling of our synthetic fuel production facilities for approximately eight weeks during the summer due to high oil prices and the partial phase-out of the tax credits for the production of synthetic fuel due to high oil prices and the resulting reduction in revenues from the third-party investors. Excluding synthetic fuel, TECO Coal benefited from the contracts signed in 2005 and early 2006 during a period of very strong coal prices.

We also completed the disposition of the remaining assets associated with the merchant power plants and small energy services businesses in 2006. We sold the remaining McAdams Power Station assets along with the site, two unused stream turbines and a district cooling plant in Miami, Florida.

Outlook

Focus on Our Core Businesses

For 2007, we plan to continue to focus on improving earnings and maintaining our strong cash and liquidity positions (see the **Liquidity, Capital Resources** section). We currently estimate our 2007 per share results from continuing operations, excluding synthetic fuel, to be in a range of $0.97 to $1.07. This estimate is driven by the expected continued customer and energy sales growth at the Florida utilities, lower coal production at TECO Coal at margins consistent with 2006 levels, continued strong river barge rates and good operations in the oceangoing business at TECO Transport, and continued strong operating results at TECO Guatemala. This estimate also includes expected lower parent interest expense as a result of debt retirements completed in 2006 and planned in 2007.

In 2007, we expect reported net income calculated in accordance with Generally Accepted Accounting Principles (GAAP) to include approximately $0.33 per share of benefits expected from synthetic fuel production. Cash generated by synthetic fuel production in 2007 will help add to the cash position that we have built for future debt retirement. Due to the idling of the synthetic fuel production facilities for a portion of 2006 and the end of the program after 2007, we think it is important to provide a non-GAAP results measure that excludes all costs or benefits related to the production of synthetic fuel. This measure provides investors additional information to assess the company's results and future earnings potential without the production of synthetic fuel.

Since July 2006, we have provided two measures to allow comparison of our results both with and without synthetic fuel. They are non-GAAP results from continuing operations including benefits from the production of synthetic fuel (Non-GAAP Results With Synthetic Fuel), which exclude certain charges and gains but include synthetic fuel, and non-GAAP results excluding synthetic fuel (Non-GAAP Results Excluding Synthetic Fuel), which excludes charges, gains and benefits associated with the production of synthetic fuel (see the **Non-GAAP Information** section). We will continue to provide Non-GAAP Results Excluding Synthetic Fuel, and are providing our 2007 results expectations on this basis.

With the expiration of the synthetic fuel tax credits at the end of 2007, we expect to partially mitigate the corresponding reduction in earnings and cash flow that will result by optimizing our coal operations, improving results from all of the operating companies, and reducing interest expense at the parent level. We expect that interest expense will be lower in 2008 as a result of our planned retirement of the remaining TECO Energy parent debt maturing in 2007, as well as the retirements accomplished in 2006.

These forecasted results are based on our current assumptions described in each operating company discussion, which are subject to risks and uncertainties (see the **Risk Factors** section).

We are maintaining our priorities for the use of cash to improve our financial profile through debt reductions at the TECO Energy parent level and to invest in our regulated businesses. Our near-term debt reduction efforts are focused on the retirement of the remaining 2007 debt maturities and longer-term on reducing parent-level debt by an additional $500 million in the 2008 to 2010 period. We expect to make an additional $80 million equity contribution to Tampa Electric in 2007 to support its continued capital spending for environmental controls and to serve its growing customer base.

Capital expenditures increased in 2006, primarily at Tampa Electric for additional peak-load generating units, equipment to control NO_x emissions and heat rate and capacity factor improvements in coal-fired units. We also invested in new mining equipment and mines at TECO Coal. We forecast capital expenditures to increase further in the 2007 through 2011 period at Tampa Electric to meet normal customer growth and generation plant maintenance, for distribution system improvements to provide higher reliability, for its portion of transmission system expansion and upgrades in the Central Florida area to meet the new National Electric Reliability Council (NERC) reliability standards, for modest distribution system expansion at Peoples Gas, and for the completion of incremental production capacity increases at TECO Coal that commenced in 2006 (see the **Liquidity, Capital Resources** section). In addition, Tampa Electric is evaluating alternatives for meeting its needs for additional generating capacity in the 2009 – 2013 period, including the potential for new baseload generating capacity in 2013, which will affect capital spending in 2008 through 2012 and is not reflected in our current forecast (see the **Capital Expenditures** section).

Expected Effects of Synthetic Fuel Production on Cash and Earnings

A major source of the GAAP earnings and cash that we expect to generate in 2007 comes from TECO Coal's previously completed sales of ownership interests in its synthetic fuel production facilities and the synthetic fuel related tax credits generated for the third-party owners. In 2007, the synthetic fuel tax credits could be reduced if oil prices exceed a certain threshold level and completely phased out if oil prices exceed the top of a range, which we estimate to be a range of $63 to $79 per barrel, as measured on a New York Mercantile Exchange (NYMEX) basis.

In January 2007, TECO Coal entered into oil price hedge instruments that protect against the risk of a reduction in the revenues we expect from the third-party investors from the production of synthetic fuel in 2007 due to high oil prices. When combined with hedges entered into in October 2006, the additional instruments protect approximately $195 million of the gross cash benefits expected from the third-party investors for the production of synthetic fuel over the full expected average annual oil price range of $63 to $79 per barrel on a NYMEX basis. The hedges in place provide very close to a dollar-for-dollar recovery of lost synthetic fuel revenues in the event of a phase-out over the estimated phase-out range. The total cost of the hedges was approximately $37 million.

The value of the hedge instruments may vary during the year, depending on year-to-date actual oil prices plus oil price futures for the remainder of the year, which will be reflected as mark-to-market adjustments in quarterly earnings from synthetic fuel production.

The following table illustrates the estimated components of synthetic fuel earnings and cash at various oil prices for the 5.7 million tons of synthetic fuel production expected in 2007.

2007 Synthetic Fuel Earnings and Cash

(millions) NYMEX Price	Phase Out	Investor Revenue	Production Cost [1]	Hedge Cost	Hedge Payoff	Net Cash	Net Income
<$63	0%	$195	$58	$37	$ 0	$100	$70
65	12%	172	58	37	23	100	70
67	25%	146	58	37	49	100	70
69	38%	121	58	37	74	100	70
71	50%	98	58	37	97	100	70
73	63%	72	58	37	123	100	70
$79	100%	$ 0	$58	$37	$195	$100	$70

(1) Incremental costs associated with the production of synthetic fuel.

TECO Coal has agreements with the investors in its synthetic fuel production facilities that provide TECO Coal with flexibility to cease producing synthetic fuel under certain conditions. If the calendar-year average oil price, on the basis of actual plus futures prices, exceeds $62 per barrel on a NYMEX basis, TECO Coal has the right to cease or reduce production, and the third-party investors have the right to not participate in the production (see the **TECO Coal** section).

The tax credit program will expire on Dec. 31, 2007, and while we do not expect the period for the tax credit program to be extended or renewed in the current form, we are assuming that there will be no change in the current legislation. Based on the assumption that the program expires 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 a level that keeps its total production similar to amounts expected to be sold in 2007. When production of synthetic fuel ends in 2008, 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, and its ability to manage production costs.

Results Summary

Our results in 2006 reflect lower earnings from the production of synthetic fuel at TECO Coal, lower earnings at Tampa Electric, and lower earnings at TECO Guatemala partially offset by improved results at TECO Transport, slightly higher results at PGS, the elimination of operating losses related to merchant power activities, and lower parent-level interest expense. In 2006, net income and earnings-per-share were $246.3 million, or $1.19 per share, compared to $274.5 million, or $1.33 per share, in 2005. Net income and earnings-per-share from continuing operations were $244.4 million, or $1.18 per share, in 2006, compared to $211.0 million, or $1.02 per share, in 2005. Results in 2006 included a $32.1 million, or $0.16 per share, benefit to earnings from synthetic fuel production, compared to $82.4 million, or $0.40 per share, in the 2005 period. In 2006, results from continuing operations also included an $8.1 million after-tax gain from the sale of the McAdams Power Station assets, $5.7 million of after-tax gains from the sale of two unused steam turbines, and $3.0 million of after-tax charges related to Hurricane Katrina damage at TECO Transport. In 2005, results from continuing operations included $46.7 million, or $0.23 per share, of after-tax charges for early debt retirement, and a $14.6 million after-tax, or $0.07 per share, loss at TWG Merchant related primarily to the unfinished Dell and McAdams merchant power plants. Results from discontinued operations in 2006 primarily included the recovery of amounts that had been previously written off and tax adjustments at the small energy services companies.

The table below compares our GAAP net income to our non-GAAP measures. A reconciliation between GAAP net income and the two non-GAAP measures is contained in the **GAAP to non-GAAP reconciliation** tables for each year shown, which follows hereafter. A non-GAAP financial measure is a numerical measure 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 (see the **Non-GAAP Information** section).

Results Comparisons

(millions)	*2006*	*2005*	*2004*
Net income (loss)	**$246.3**	$274.5	$(552.0)
Net income (loss) from continuing operations	**$244.4**	$211.0	$(355.5)
Non-GAAP Results With Synthetic Fuel	**$233.6**	$254.7	$ 153.1
Non-GAAP Results Excluding Synthetic Fuel	**$201.5**	$172.3	$ 73.1

Our results in 2005 were driven by stronger markets for TECO Coal and TECO Transport, continued customer and energy sales growth at Tampa Electric and Peoples Gas, and lower TECO Energy parent-level interest expense. In 2005, net income and earnings-per-share were $274.5 million and $1.33, respectively, compared to a loss of $552.0 million and a per-share loss of $2.87 in 2004. Results in 2005 included the $45.0 million after-tax debt-extinguishment charge associated with the June 2005 redemption of $380 million of 10.5% notes and a $76.5 million after-tax gain recorded in discontinued operations upon the final sale and transfer of the Union and Gila River power stations to the lenders in May 2005. The gain represented the reversal of the accumulated unfunded operating losses recorded against equity for the period from Dec. 31, 2003, the date we decided to exit the projects, through the effective date of the transfer to the lenders group. Also included in results are smaller charges and gains, which are detailed in the table that reconciles 2005 GAAP net income to non-GAAP results. Results from discontinued operations in 2005 include the operating results for the Union, Gila River and Commonwealth Chesapeake power stations until the time of the transfers to the respective buyers, including the gain on the transfer discussed above, and true-up amounts from previously divested assets.

In 2005, net income and earnings-per-share from continuing operations were $211.0 million and $1.02, respectively, compared to a loss of $355.5 million and a per-share loss of $1.85 for 2004. Non-GAAP Results With Synthetic Fuel, which exclude certain charges and gains included in GAAP net income from continuing operations but includes synthetic fuel, were $254.7 million in 2005, compared to $153.1 million in 2004. In 2005, results from continuing operations reflected improved results from the business segments, particularly the unregulated businesses. TECO Coal's net income was significantly higher, driven by higher prices for coal and the sale of an additional 8% ownership interest in its synthetic fuel production facilities. TECO Transport's increased earnings reflected higher river barge rates due to better balance in supply and demand, and the qualification of two vessels for the positive benefit of tax law changes under the Jobs Creation Act. TECO Guatemala reported strong results from continued good operation of the power generating plants, customer and energy sales growth at the distribution utility and favorable tax rates due to the Jobs Creation Act. Tampa Electric and Peoples Gas both experienced continued customer and energy sales growth.

2006 Earnings Summary

(millions) Except per-share amounts	*2006*	*2005*	*2004*
Consolidated revenues	**$3,448.1**	$3,010.1	$2,639.4
Earnings (loss) per share – basic			
Earnings (loss) per share	**$ 1.19**	$ 1.33	$ (2.87)
Discontinued operations	**0.01**	0.31	(1.02)
Earnings (loss) from continuing operations	**$ 1.18**	$ 1.02	$ (1.85)
Earnings (loss) per share – diluted			
Earnings (loss) per share	**$ 1.18**	$ 1.31	$ (2.87)
Discontinued operations	**0.01**	0.31	(1.02)
Earnings (loss) from continuing operations	**$ 1.17**	$ 1.00	$ (1.85)
Net income (loss)	**$ 246.3**	$ 274.5	$(552.0)
Net income (loss) from discontinued operations	**1.9**	63.5	(196.5)
Charges and (gains) from continuing operations(1)	**(10.8)**	43.7	508.6
Non-GAAP Results With Synthetic Fuel(2)	**233.6**	254.7	153.1
Synthetic fuel impact	**(32.1)**	(82.4)	(80.0)
Non-GAAP Results Excluding Synthetic Fuel(2)	**$ 201.5**	$ 172.3	$ 73.1
Average common shares outstanding			
Basic	**207.9**	206.3 (4)	192.6 (3)
Diluted	**208.7**	208.2 (4)	192.6 (3)

(1) See the GAAP to non-GAAP reconciliation tables that follow.

(2) A non-GAAP financial measure is a numerical measure 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 (see the **Non-GAAP Information** section).

(3) Average shares outstanding for 2004 include 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.

(4) Average shares outstanding for 2005 include the issuance of 6.85 million shares in conjunction with the final settlement of the 9.5% adjustable conversion-rate equity security units.

The following tables show the specific adjustments made to GAAP net income for each segment to develop our non-GAAP results.

2006 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Transport*	*TECO Guatemala*	*Parent/ Other*	*Total*
GAAP Net income from continuing operations	$135.9	$29.7	$78.8	$22.8	$37.6	$(60.4)	$244.4
Hurricane costs	—	—	—	4.5	—	—	4.5
Hurricane insurance recoveries	—	—	—	(1.5)	—	—	(1.5)
Dell and McAdams valuation adjustment and gain on sale, net	—	—	—	—	—	(8.1)	(8.1)
Gain on sale of unused steam turbines	—	—	—	—	—	(5.7)	(5.7)
Total charges and (gains)	—	—	—	3.0	—	(13.8)	(10.8)
Non-GAAP Results With Synthetic Fuel	135.9	29.7	78.8	25.8	37.6	(74.2)	233.6
Synthetic fuel impact	—	—	(32.1)	—	—	—	(32.1)
Non-GAAP Results Excluding Synthetic Fuel	$135.9	$29.7	$46.7	$25.8	$37.6	$(74.2)	$201.5

2005 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Transport*	*TECO Guatemala*	*TWG Merchant*	*Parent/ Other*	*Total*
GAAP Net income from continuing operations	$147.1	$29.6	$115.4	$20.2	$40.4	$(14.6)	$ (127.1)	$ 211.0
Debt extinguishment charges	—	—	—	—	—	—	46.7	46.7
Hurricane costs	—	—	—	12.6	—	—	—	12.6
Hurricane insurance recoveries	—	—	—	(13.7)	—	—	—	(13.7)
Dell & McAdams valuation adjustment	—	—	—	—	—	(1.9)	—	(1.9)
Total charges and (gains)	—	—	—	(1.1)	—	(1.9)	46.7	43.7
Non-GAAP Results With Synthetic Fuels	147.1	29.6	115.4	19.1	40.4	(16.5)	(80.4)	254.7
Synthetic fuel impact	—	—	(82.4)	—	—	—	—	(82.4)
Non-GAAP Results Excluding Synthetic Fuel	$147.1	$29.6	$ 33.0	$19.1	$40.4	$ (16.5)	$ (80.4)	$ 172.3

2004 Reconciliation of GAAP net income from continuing operations to non-GAAP results

Net income impact (millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Transport*	*TECO Guatemala*	*TWG Merchant*	*Parent/ Other*	*Total*
GAAP Net income from continuing operations	$146.0	$27.7	$61.3	$10.2	$ 5.7	$(534.1)	$(72.3)	$(355.5)
Merchant power valuations	—	—	—	—	—	480.7	—	480.7
Steam turbine valuations	—	—	—	—	12.8	—	—	12.8
Debt extinguishment charges	—	—	—	—	6.7	—	(0.5)	6.2
Taxes on cash repatriation	—	—	—	—	17.4	—	—	17.4
Asset impairment	—	—	—	0.6	—	—	—	0.6
Restructuring charges	—	0.4	—	1.1	—	—	5.0	6.5
Valuation adjustment	—	—	—	—	—	—	3.4	3.4
Tax credit reversals	—	—	(7.0)	—	—	—	—	(7.0)
Gain on sale of propane business	—	—	—	—	—	—	(12.0)	(12.0)
Total charges and (gains)	—	0.4	(7.0)	1.7	36.9	480.7	(4.1)	508.6
Non-GAAP Results With Synthetic Fuel	146.0	28.1	54.3	11.9	42.6	(53.4)	(76.4)	153.1
Synthetic fuel impact	—	—	(80.0)	—	—	—	—	(80.0)
Non-GAAP Results Excluding Synthetic Fuel	$146.0	$28.1	$(25.7)	$11.9	$42.6	$ (53.4)	$(76.4)	$ 73.1

Non-GAAP Information

From time to time, in this Management's 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 none of the particular excluded items is 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. With the exception of synthetic fuel, hurricane costs and hurricane related insurance recoveries, substantially all of the items included in charges and gains for the periods detailed in the tables above are associated with our exit from the merchant power business and small energy services businesses.

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 and separate non-GAAP measures, 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 segment revenues, net income, and earnings per share contributions from continuing operations of our business segments (see **Note 14** to the TECO Energy **Consolidated Financial Statements**).

(millions) Except per share amounts		*2006*	*2005*	*2004*
Segment Revenues [1]				
Regulated companies	Tampa Electric	**$2,084.9**	$1,746.8	$1,687.4
	Peoples Gas	**577.6**	549.5	417.2
Total regulated		**2,662.5**	2,296.3	2,104.6
Unregulated companies	TECO Coal	**574.9**	505.1	327.6
	TECO Transport	**308.5**	278.2	249.6
	TECO Guatemala [2]	**7.6**	7.7	11.5
	TWG Merchant[3]	**-**	0.4	7.6
Total unregulated		**$ 891.0**	$ 791.4	$ 596.3
Net Income (loss) [4]				
Regulated companies	Tampa Electric	**$ 135.9**	$ 147.1	$ 146.0
	Peoples Gas	**29.7**	29.6	27.7
Total regulated		**165.6**	176.7	173.7
Unregulated companies	TECO Coal	**78.8**	115.4	61.3
	TECO Transport	**22.8**	20.2	10.2
	TECO Guatemala[5]	**37.6**	40.4	5.7
	TWG Merchant	**-**	(14.6)	(534.1)
Total unregulated		**139.2**	161.4	(456.9)
Parent/other		**(60.4)**	(127.1)	(72.3)
Net income from continuing operations		**244.4**	211.0	(355.5)
Discontinued operations		**1.9**	63.5	(196.5)
Net income (loss)		**$ 246.3**	$ 274.5	$(552.0)
Earnings per Share - Basic [6]				
Regulated companies	Tampa Electric	**$ 0.65**	$ 0.71	$ 0.76
	Peoples Gas	**0.14**	0.14	0.14
Total regulated		**0.79**	0.85	0.90
Unregulated companies	TECO Coal	**0.38**	0.56	0.32
	TECO Transport	**0.11**	0.10	0.05
	TECO Guatemala[5]	**0.18**	0.20	0.03
	TWG Merchant	**-**	(0.07)	(2.77)
Total unregulated		**0.67**	0.79	(2.37)
Parent/other		**(0.28)**	(0.62)	(0.38)
Earnings (loss) from continuing operations		**1.18**	1.02	(1.85)
Discontinued operations		**0.01**	0.31	(1.02)
EPS Total		**$ 1.19**	$ 1.33	$ (2.87)

(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). Segment revenues include intercompany transactions that are eliminated in the preparation of TECO Energy's consolidated financial statements.

(2) TECO Guatemala was deconsolidated under FIN 46R effective Jan. 1, 2004. Actual revenues in 2006, 2005 and 2004, which are not included in this table due to the effects of deconsolidation, were $113.7 million, $104.0 million and $102.1 million, respectively. **Note 14** to the **TECO Energy Consolidated Financial Statements** provides additional information and the condensed financial information for the Guatemalan operations.

(3) Effective with 2006 only historical information is provided for TWG Merchant. Any remaining results are included in Parent/other.

(4) Segment net income and earnings are reported on a basis that includes internally allocated financing costs to the unregulated companies. Internally allocated finance costs for 2006, 2005 and 2004 were at a pretax rate of 8%, based on the average investment in each unregulated subsidiary.

(5) In 2004, results for TECO Guatemala included various charges related to merchant power activities recorded in that segment, but unrelated to its basic operations (see the **2004 GAAP to non-GAAP reconciliation** table).

(6) The number of shares used in the earnings-per-share calculations are basic shares.

Tampa Electric

Electric Operations Results

Tampa Electric is entering a period of growth through increasing capital expenditures to support customer growth, statewide transmission system reliability standards, implementation of the storm hardening plans mandated by the Florida Public Service Commission (FPSC) and additional baseload generating capacity needs.

Tampa Electric's 2006 net income was $135.9 million, compared to $147.1 million in 2005. These results were driven by the planned increase in non-fuel operations expense, which more than offset continued strong customer growth and slightly higher energy sales. Weather patterns in 2006 resulted in 3% lower total degree-days than normal but 1% higher total degree-days than

2005, when total degree-days were 5% below normal. Results also included a $9.4 million after-tax disallowance by the FPSC for the recovery of a portion of the waterborne transportation costs for the delivery of solid fuel (see the **Regulation** section).

Tampa Electric's 2005 net income was $147.1 million, compared to $146.0 million in 2004. These results were driven by continued strong customer growth and higher energy sales partially offset by weather patterns that resulted in 5% lower total degree-days than normal and 1% lower total degree-days than 2004, when total degree-days were 3% below normal, and higher non-fuel operating expenses, which include higher depreciation expense from normal plant additions. Results also included an $8.6 million after-tax disallowance by the FPSC for the recovery of a portion of the waterborne transportation costs for the delivery of solid fuel (see the **Regulation** section).

Summary of Operating Results

(millions)	*2006*	*% Change*	*2005*	*% Change*	*2004*
Revenues	**$2,084.9**	19.4	$1,746.8	3.5	$1,687.4
Other operating expenses	**220.3**	9.7	200.8	5.4	190.5
Maintenance	**107.7**	22.2	88.1	1.0	87.2
Depreciation	**186.3**	-0.4	187.1	3.4	180.9
Taxes, other than income	**138.1**	9.8	125.8	4.1	120.8
Non-fuel operating expenses	**652.4**	8.4	601.8	3.9	579.4
Fuel	**906.8**	65.8	546.8	-10.8	612.9
Purchased power	**221.3**	-17.9	269.7	56.5	172.3
Total fuel expense	**1,128.1**	38.2	816.5	4.0	785.2
Total operating expenses	**1,780.5**	25.5	1,418.3	3.9	1,364.6
Operating income	**$ 304.4**	-7.3	$ 328.5	1.8	$ 322.8
AFUDC equity	**$ 2.7**	—	$ —	—	$ 0.7
Net income	**$ 135.9**	-7.6	$ 147.1	0.8	$ 146.0
Megawatt-Hour Sales (thousands)					
Residential	**8,721**	1.9	8,558	3.2	8,293
Commercial	**6,357**	2.0	6,234	4.1	5,988
Industrial	**2,279**	-8.0	2,478	-3.1	2,556
Other	**1,668**	1.6	1,642	2.6	1,600
Total retail	**19,025**	0.6	18,912	2.6	18,437
Sales for resale	**862**	11.5	773	16.4	664
Total energy sold	**19,887**	1.0	19,685	3.1	19,101
Retail customers-thousands (average)	**653.7**	2.8	635.7	2.6	619.5

Tampa Electric Operating Revenues

Retail megawatt-hour sales rose 0.6% in 2006, driven by customer growth despite the effects of mild weather. In 2006, average annual customer growth of 2.8% (almost 18,000 new customers) was partially offset by mild weather and 1% lower average residential per-customer energy usage. Total degree days in Tampa Electric's service area were 3% below normal but 1% above 2005. Tampa Electric estimates that the pattern of mild weather characterized by relatively few sustained periods of extreme temperatures reduced energy sales approximately 1% in 2006 compared to normal weather patterns.

In 2006, energy consumption per residential customer declined due to the combined effects of weather, price elasticity and changes in residential building trends. One of the factors contributing to this phenomenon is an increase in the number of condominiums and multi-family units, such as apartments, recently completed in the Tampa metropolitan area. Condominiums and multi-family units, which comprised about 36% of new customers in 2006, tend to have fewer square feet of air conditioned space per residence and use less energy per square foot due to more energy efficient construction. In addition, the higher costs for natural gas and coal, which are reflected in customers' bills through the fuel adjustment clause, have caused customers to use less electricity in general. On a weather-normalized basis, retail energy sales to customers other than the phosphate industry, which is not weather-sensitive, increased 1.8% in 2006 compared to 2005.

Electricity sales to the lower margin industrial customers in the phosphate industry decreased an additional 18.5% in 2006 after a 6.5% decrease in 2005. The decline in sales to phosphate customers was driven by the idling of some mining operations in 2006 due to market conditions for the product. The longer-term decline in sales to phosphate customers reflects the natural reserve depletion and migration of mining operations out of Tampa Electric's service area. Base revenues from phosphate sales represented less than 2% of base revenues in 2006 and less than 3% in 2005. Sales to commercial customers increased 2.0% in 2006, driven by the strong local economy.

Base rates for all customers were unchanged in 2006. Fuel-related revenues increased in 2006 and 2005 under the FPSC-approved fuel cost recovery clause, due to the recovery of previous under-recoveries of fuel expense in 2005 and 2004 and higher gas prices. Customers' rates under the fuel clause increased in 2007 in accordance with the rates approved by the FPSC in November 2006, to reflect higher fuel costs, the under-recovery of $51 million of 2006 fuel cost due to higher cost of natural gas early in the year and the remaining $107 million portion of previously under-recovered 2005 fuel costs partially offset by the sale of a net $45 million of excess sulfur dioxide (SO_2) emission credits, which appears as a credit on customers' bills through the Environmental Cost Recovery Clause (see the **Regulation** section).

Energy sold to other utilities for resale increased 11% in 2006 due to a new contract for wholesale energy sales with a new customer and increased wholesale sales volumes to an existing customer. Energy sold to other utilities for resale increased in 2005 due to a planned increase in the energy sold under a long-term contract.

Energy Sales Growth Forecast

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 about 2.8% annually. This energy sales growth projection is 0.2% lower than previous projections to reflect the change in usage patterns experienced in 2006. Tampa Electric's forecasts indicate that summer retail peak demand growth is expected to average more than 135 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 **Risk Factors** section).

The economy in Tampa Electric's service area continued to grow in 2006, aided by continued population growth in Florida, the region's relatively low labor rates and attractive cost of living. The Tampa metropolitan area's non-farm employment grew 2.0% in 2006, despite a 3.9% decline in construction employment, due to the strong local economy. Employment grew 2.5% in 2005 as the local economy recovered from the U.S. economic slowdown in the first half of 2004. The local Tampa area unemployment rate increased slightly to 3.0% at year-end 2006, compared with 2.9% in December 2005, and 4.6% in December 2004. These rates are lower than the year-end 3.3% unemployment rate for the State of Florida and 4.5% for the nation at Dec. 31, 2006.

As in many areas of the country, the housing market in Tampa Electric's service area slowed in 2006 after significant growth in 2004 and 2005. The numbers of existing homes for sale and unsold new homes has increased over the 2005 and 2004 levels. Economists and real estate associations indicate that, while inventories of unsold homes are above the past two years, the housing market is expected to start to recover in late 2007.

Tampa Electric Operating Expenses

Total operating expense increased in 2006 primarily due to higher costs for coal partially offset by lower purchased power expense due to increased coal-fired generation from improved coal-fired unit availability. Non-fuel operations and maintenance expense increased, as planned, by $24.3 million after-tax. This increase reflected, among other items, after-tax increases of $8.3 million of additional spending on transmission and distribution system reliability and customer service enhancements, $5.3 million of additional spending on coal-fired unit performance improvements, $6.3 million of higher employee-related costs and $3.3 million of increased property insurance cost.

Total operating expenses increased in 2005 due to higher purchased power expenses as a result of lower coal-fired unit availability and the higher cost of natural gas for all utilities in Florida that is reflected in the cost of purchased power. Non-fuel operating and maintenance expenses increased as a result of higher power distribution expenses in 2005 due to more normal work activities following the 2004 hurricane restoration efforts. Other non-fuel operations and maintenance expenses increased due to increased employee-related expenses for items such as pensions, disability and medical reserves, and higher customer expenses, which included higher levels of uncollectible accounts.

Non-fuel operations and maintenance expenses are expected to increase at about inflationary levels in 2007 after the significant step up in 2006. The 2006 non-fuel operations and maintenance expense increase was for enhanced customer service, distribution system reliability improvements and to improved coal-fired generating unit availability and capacity factors. That portion of the higher non-fuel operations and maintenance expense related to the initial implementation of elements of the storm hardening plan that was submitted to and approved by the FPSC in 2006 are expected to continue with the full implementation of the storm hardening plan in 2007.

Depreciation decreased in 2006 due to the retirement of short-lived fully depreciated assets, such as telecommunications equipment, tools and test equipment, which more than offset the additional depreciation associated with normal plant additions. Depreciation expense is projected to increase in 2007, due to normal plant additions to serve Tampa Electric's growing customer base and maintain system reliability and a partial year of depreciation on the first NO_x control project to be completed on Big Bend Unit 4, which is expected to enter service in May. Depreciation expense increased in 2005 due to normal plant additions to serve the growing customer base.

Fuel Prices and Fuel Cost Recovery

Under regulatory accounting, the cost of fuel on the income statement represents the amounts authorized by the FPSC for recovery through the fuel adjustment clause, but the actual cost of fuel purchased may differ from those amounts. The difference between actual fuel cost and the amount authorized for recovery is deferred on the balance sheet as either under- or over-recovered fuel cost, and therefore does not impact net income.

Included in Tampa Electric's fuel adjustment filing for rates effective in 2007 was $51 million of 2006 under-recovered fuel cost and the remaining $107 million of 2005 under-recovered fuel cost that was incurred after the 2006 fuel filing was made. In

November 2006, the FPSC authorized the recovery of this amount and the full projected 2007 fuel expense (see the **Regulation** section). The increase in the fuel adjustment clause will be partially offset by a $35 million net benefit to customers primarily from the sale of excess SO_2 emission credits, which appears as a credit on customers' bills through the Environmental Cost Recovery Clause (see the **Regulation** section).

Fuel prices increased in 2006 driven primarily by higher natural gas prices early in the year and higher coal prices throughout the year. For the year, at $9.61/mmBTU, the average delivered cost of natural gas decreased compared to 2005 when natural gas prices spiked upward following hurricanes Katrina and Rita. Coal prices also increased during that period from a delivered cost of $2.14 per million BTU in 2004 to $2.49 per million BTU in 2006 due to supply and demand for utility steam coal.

Natural gas prices were extremely volatile during the 2004 through 2006 period as a result of supply constraints due to damage to production and transportation infrastructure from hurricanes and increased demand nationwide due to the higher percentage of electricity now being generated from natural gas-fired generation, particularly during peak-load periods. Natural gas price volatility is expected to continue due to the balance in supply and demand and market prices being driven by commodity investors rather than physical supply users. Coal prices, while less volatile, have increased steadily for the past three years. Coal prices are expected to decline in 2007 due to the current over supply of steam coal in the U.S. market following a mild summer in 2006 and a mild start to the winter (see the **TECO Coal** section).

Energy Supply

On a retail energy supply basis, Tampa Electric generation accounted for 95%, 92% and 95% of the total retail energy sales in 2006, 2005 and 2004, respectively, with the remainder of the energy supplied by purchased power. Purchased power expense decreased 18% and the volume of power purchased decreased 17% in 2006 due to improved coal-fired unit availability and generation. The amount of power purchased by Tampa Electric to serve its customers increased in 2005 following a decrease in 2004, primarily due to lower coal-fired unit availability. Purchased power is expected to increase in 2007 due to the planned extended maintenance period on Big Bend Unit 4 for the completion of the SCR project for that unit.

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 baseload units at Big Bend and the coal gasification unit, Polk Unit One. Beginning in 2007 and through 2010, one of the four Big Bend coal-fired units will undergo an extensive outage each year to complete the construction of the NO_x control equipment (see the **Environmental Compliance** section), which is expected to reduce the generation from coal in those years.

Hurricane Storm Hardening

Due to extensive storm damage to utility facilities during the 2004 and 2005 hurricane seasons and the resulting outages utility customers experienced throughout the state, in 2006 the FPSC initiated proceedings to explore methods of designing and building transmission and distribution systems that would minimize long-term outages and restoration costs.

The FPSC subsequently issued an order requiring all investor owned utilities (IOUs) to implement a 10-point storm preparedness plan designed to improve the statewide electric infrastructure to better withstand severe storms and expedite recovery from future storms. In addition to a wood pole inspection program instituted separately, the plans address vegetation management, audits of pole attachments, transmission structure inspections and hardening, data gathering and analysis, natural disaster planning, coordination with local governmental agencies and collaborative research. In October 2006, the FPSC approved Tampa Electric's plan to comply with the directive. Tampa Electric is implementing its plan and estimates that the average incremental non-fuel operations and maintenance expense of this plan to be approximately $15 million annually.

The FPSC also modified its rule regarding the design standards for new and replacement transmission and distribution line construction, including certain critical circuits in a utility's system. Beyond employing accepted engineering practices and complying with the applicable edition of the National Electric Safety Code (NESC), the new design standard requires adoption of the NESC extreme wind loading standards for distribution facilities. The new design standards also encourage the placement of new or modified facilities underground when feasible. These new requirements are expected to increase the capital expenditures required to expand the system to meet growing customer demand and to maintain system reliability by approximately $20 million annually (see the **Regulation** section).

Higher Capital Spending

Tampa Electric is entering a period of increasing capital spending for infrastructure to reliably serve its growing customer base and to address the needs for future baseload generating capacity additions. In addition to the capital spending to comply with the storm hardening plan described above and the need for additional generating capacity discussed below, Tampa Electric expects to make additional capital investments for its pro rata portion of transmission system improvements to meet the new NERC reliability standards for Central Florida. It also expects to invest additional amounts in its transmission and distribution system to improve reliability and reduce customer outages.

Based on its current forecast of energy demand and sales growth, Tampa Electric has identified a need for new baseload capacity in early 2013 due to continued customer growth and the expiration of a long-term power purchase agreement with Hardee Power Partners. Its options to satisfy the baseload capacity need range from purchasing the power to constructing its own generating facility. Tampa Electric has initiated a request for proposal (RFP) process, for interim peak capacity needs and, as required in Florida for baseload capacity additions, to potentially purchase the needed power under power purchase agreements. If construction of a baseload generating unit by Tampa Electric is found to be the most cost-effective method to meet customers' needs, there are additional regulatory and permitting steps required prior to Tampa Electric moving forward with such a construction program.

The capital expenditures required under the various options currently being evaluated vary significantly from only transmission system improvements to allow the import of power to the construction of peaking capacity and baseload capacity. In addition to an evaluation of the purchase versus build option, Tampa Electric has options regarding the type of baseload plant to be constructed, ranging from natural gas-fired combined cycle to an Integrated Gasification Combined Cycle (IGCC) unit. Tampa Electric's preferred option is a 630-megawatt, coal- and petroleum coke-fueled IGCC unit in order to diversify its own fuel mix (which is expected to be more than 50% natural gas by that time); to meet the State of Florida's goal of diversifying the fuel supplies used to generate power; and to take advantage of an IGCC unit's ability to more easily capture and sequester carbon dioxide (CO_2) emissions if required in the future (see the **Capital Expenditures** and **Environmental Compliance** sections). In 2006, under the Energy Policy Act of 2005, Tampa Electric was awarded an opportunity to receive $133.5 million of tax credits from the Internal Revenue Service (IRS) and U.S. Department of Energy (DOE) for its proposed IGCC plant.

In 2006, the Florida Legislature enacted a new statute related to new nuclear plants that might be constructed in Florida that provided for, among other things, the recovery of pre-construction costs and carrying costs of construction through the capacity cost recovery clause; a base rate increase when the plant is put in service to recover the costs of the plant; and the recovery of prudently incurred costs in the event that the plant is not completed. Tampa Electric is seeking similar legislative treatment for IGCC plants as they accomplish the same goal of increasing fuel diversity in Florida.

Tampa Electric has not sought a base rate increase since 1992. Since that last rate proceeding it has earned within its allowed ROE range while adding almost 190,000 customers and making significant investments in facilities and infrastructure, including baseload and peaking generating capacity additions, to serve the growing customer base. Over time, current base rates may not support the additional transmission and distribution system reliability capital spending, storm hardening capital and operations and maintenance spending, other recurring capital expenditures and generally higher non-fuel operations and maintenance expenditures and still earn a return within its allowed ROE range.

Peoples Gas

Operating Results

PGS reported net income of $29.7 million in 2006, compared to $29.6 million in 2005. Customer growth of 3.3%, increased sales to residential customers, and strong sales to power generating and off-system customers due to declining natural gas prices were partially offset by non-fuel operation and maintenance expenses that were $2.2 million higher. The higher off-system sales and increased volumes transported for power generation customers helped offset the impact of mild winter weather early in the year and then again in December 2006. After a very strong 2005 performance, sales to commercial customers declined slightly due to higher natural gas prices in early 2006. Results in 2006 included $1.7 million from the small energy services companies, which provide marketing, sales support and gas management services.

In 2006, the total throughput for PGS was 1.3 billion therms. Of this total throughput, 11% was gas purchased and resold to retail customers by PGS, 70% was third-party supplied gas that was delivered for retail transportation-only customers, and 19% was gas sold off-system. Industrial and power generation customers consumed approximately 65% of PGS' annual therm volume, commercial customers used approximately 29%, and the balance was consumed by residential customers.

PGS had 2005 net income of $29.6 million, compared with $27.7 million for the same period in 2004, including the 2004 restructuring charge (see the **2004 GAAP to non-GAAP reconciliation** table). Customer growth of 3.6%, increased sales to residential and commercial customers and increased off-system sales were partially offset by higher operations and maintenance expenses in 2005. Results in 2005 reflected strong sales to commercial customers as a result of growth in the Florida economy and high levels of tourism, which enhanced commercial sales to hotels and restaurants, while sales of low-margin transportation service for interruptible customers declined.

In 2005, residential and commercial therm sales increased through customer growth and increased usage per customer. Increased residential usage reflected increased sales to customers with multiple uses for gas as a result of marketing to high-end residential developers. The increased commercial usage reflected the continued strong Florida economy and the strong 2005 tourist business at hotels, restaurants and theme parks served by PGS.

While the residential market represents only a small percentage of total therm volume, residential operations generally comprise 25% of total revenues. New residential construction that includes natural gas and conversions of existing residences to gas have steadily increased since the late 1980s. Like all natural gas distribution utilities, PGS is faced with potential decreases in per-customer usage due to improving appliance efficiency. As customers replace existing gas appliances with newer more efficient models, usage may decline.

Natural gas has historically been used in many traditional industrial and commercial operations throughout Florida, including production of products such as steel, glass, ceramic tile and food products. Within the PGS operating territory, large cogeneration facilities utilize gas-fired technology in the production of electric power and steam.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a Purchased Gas Adjustment (PGA). The PGA rate, which is approved by the FPSC annually, is a band and can vary monthly due to changes in actual fuel costs and normally results in lower under- or over-recovered gas cost variances at PGS than at Tampa Electric.

Summary of Operating Results

(millions)	*2006*	*% Change*	*2005*	*% Change*	*2004*
Revenues	**$577.6**	5.1	$549.5	31.7	$417.2
Cost of gas sold	**365.3**	4.3	350.2	54.8	226.2
Operating expenses	**148.5**	9.0	136.2	3.9	131.1
Operating income	**63.8**	1.0	63.1	5.3	59.9
Net income	**29.7**	0.3	29.6	6.9	27.7
Restructuring charges	—	—	—	—	0.4
Non-GAAP results	**$ 29.7**	0.3	$ 29.6	5.3	$ 28.1
Therms sold – by customer segment					
Residential	**73.0**	3.3	70.7	7.4	65.8
Commercial	**375.7**	-1.2	380.3	3.3	368.1
Industrial	**456.6**	15.7	394.6	-1.2	399.5
Power generation	**395.7**	35.7	291.7	—	291.6
Total	**1,301.0**	14.4	1,137.3	1.1	1,125.0
Therms sold – by sales type					
System supply	**391.1**	16.0	337.1	3.3	326.4
Transportation	**909.9**	13.7	800.2	0.2	798.6
Total	**1,301.0**	14.4	1,137.3	1.1	1,125.0
Customer (thousands) – average	**329.0**	3.3	318.4	3.6	307.4

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 2006, approximately 42% of PGS' non-residential customers had elected to take service under this program. Participation in this program was essentially unchanged in 2006.

Non-fuel operations and maintenance expense increased in 2006 primarily due to higher employee-related costs, such as pay and benefits. Operations and maintenance expense increased in 2005 primarily due to higher customer charges for uncollectible accounts, which have risen due to the high natural gas prices and higher personnel-related expenses. Depreciation expense increased in both years, in line with the capital expenditures made over the past several years to expand the system.

Depreciation is expected to increase in 2007 from normal plant additions and as a result of a depreciation study required every five years by the FPSC, which was approved in January 2007. Operations and maintenance expense, excluding costs related to FPSC-approved energy conservation programs recovered separately, are expected to increase at about inflationary levels.

PGS forecasts customer growth of approximately 2.5% in 2007, which is lower than the average customer growth experienced for the past five years. A major contributor to the slower growth is the slowdown in the housing market. PGS does serve some of the areas of Florida that experienced some of the most rapid growth and greatest housing price appreciation in 2005 and 2006, including the Ft. Myers and Naples areas. These areas are now experiencing the most significant impacts of the slowdown in the housing market.

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 Ft. Myers and Naples areas and the northeast coast in the Jacksonville area. PGS' expansion strategy for the past several years has been to take advantage of the significant capital investments in main pipeline expansions to connect customers to that existing infrastructure. In 2007, PGS expects its capital spending to support modest system expansion. It also expects 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 **Risk Factors** section).

Gas Supplies

PGS purchases gas from various suppliers depending on the needs of its customers. The gas is delivered to the PGS distribution system through three interstate pipelines on which PGS has reserved firm transportation capacity for delivery by PGS to its customers.

Gas is delivered by the Florida Gas Transmission Company (FGT) through more than 57 interconnections (gate stations) serving PGS' operating divisions. In addition, PGS' Jacksonville Division receives gas delivered by the South Georgia Natural Gas Company pipeline through two gate stations located northwest of Jacksonville. Gulfstream Natural Gas Pipeline initiated gas delivery in 2003 through five gate stations. The addition of the Gulfstream pipeline enhances reliability of service and helps meet the capacity needs for PGS' growing customer base.

PGS procures natural gas supplies using baseload and swing-supply contracts with various suppliers along with spot market purchases. Pricing generally takes the form of either a variable price based on published indices, or a fixed price for the contract term.

TECO Coal

TECO Coal recorded 2006 net income of $78.8 million, compared to $115.4 million in 2005. Excluding the $32.1 million benefit associated with the production of synthetic fuel, TECO Coal's full-year 2006 Non-GAAP Results Excluding Synthetic Fuel were $46.7 million, compared to $33.0 million in 2005, which excluded $82.4 million of earnings benefits from the production of synthetic fuel, (see the **2006 GAAP Results Reconciliation to Non-GAAP** table). Compared to 2005, results reflect a 13% higher average net per-ton selling price across all products, excluding transportation allowances, partially offset by higher production costs. Results also reflect a $3.8 million after-tax charge to reduce deferred tax assets consistent with a recent reduction in the Kentucky state income tax rate and a $2.7 million after-tax benefit from the true-up in 2006 of the 2005 synthetic fuel tax credit rate. The 2005 tax credit was adjusted to reflect $1.17 per million Btu on an actual basis versus the estimated $1.15 per million Btu used in 2005.

In 2006, the cash cost of production increased 12% over 2005. Higher production costs reflect higher costs associated with new safety regulations, the costs associated with relocating mining equipment from high cost mining areas and areas where the reserves were depleted, costs associated with additional exploration expenses to optimize future mining plans, and higher costs for diesel fuel, explosives, conveyor belts and steel-related products .

Total sales were 9.8 million tons in 2006, including 5.3 million tons of synthetic fuel, compared to 9.7 million tons, including 6.4 million tons of synthetic fuel in 2005. Lower synthetic fuel sales volumes reflect the idling of production facilities from late July through mid-September due to estimated average annual oil prices above the break-even level. Total coal sales were not impacted as synthetic fuel sales contracts permitted the substitution of conventional coal for synthetic fuel while the synthetic fuel production was idled.

TECO Coal's 2005 net income was $115.4 million, driven by higher selling prices and margins, on total sales of 9.7 million tons, compared to $61.3 million for the same period in 2004, which included the $7.0 million benefit from a tax credit true-up, on sales of 9.1 million tons. Full-year tonnage includes 6.4 million tons of synthetic fuel sales in 2005, compared to 6.3 million tons in the 2004 period. Results reflect an average net selling price per ton, which excludes transportation allowances, almost 48% higher than in 2004; average cash cost of sales, excluding synthetic fuel costs, almost 20% higher than in 2004; and increased third-party ownership in the synthetic fuel production facilities. The cash cost of sales was driven by higher prices for diesel fuel, labor and steel products. Results in 2005 also included a $1.6 million after-tax benefit from the 2004 synthetic fuel tax credit rate, which was $1.13 per million Btu on an actual basis versus the $1.12 per million Btu estimated in 2004, and a $2.4 million negative adjustment to deferred tax assets due to a reduction in the Kentucky state income tax rate.

Synthetic Fuel

	12 Months Ended Dec. 31	
(after-tax millions)	***2006***	*2005*
Synthetic fuel net benefit before phase-out	**$70.5**	$82.3
Phase-out impact	**(36.7)**	—
Mark-to-market gain (loss)	**(1.7)**	0.1
Net synthetic fuel earnings benefit	**$32.1**	$82.4

The benefits from the production of synthetic fuel reflect the estimated 35% reduction in revenues from third-party synthetic fuel investors based on estimated average annual oil prices of $66/Bbl at Dec. 31, 2006. The phase-out range will be based on oil prices represented by the annual average of Producer First Purchase Prices reported by the U.S. Department of Energy. Based on the actual relationship of these prices reported through October and NYMEX prices, TECO Coal estimates the initial phase-out level for 2006 to begin at $62/Bbl on a NYMEX basis, and that the tax credits would be fully phased out at $76/Bbl on a NYMEX basis. Actual Department of Energy Producer First Purchase Prices for the full year, which are normally reported in late March of the following year, may cause positive or negative adjustments to estimated 2006 results and would be recorded in the first quarter of 2007.

Actual net cash generation from synthetic fuel production in 2006 was approximately $65 million, which includes the reduction of revenue from third-party investors, the effects of the temporary idling of synthetic fuel production and the cost of production, compared to a potential $140 million without the effects of high oil prices.

In 2005, synthetic fuel production and sales were 6.4 million tons, compared to 6.3 million tons in 2004. TECO Synfuel Holdings, LLC had sold 90% of its ownership interest to two third party investors by the end of 2004, along with associated percentage rights to benefits in the business that adjust from time to time. Allocation of the benefits varied in 2004 such that more than 90% of the benefits were to third parties. Allocation of the benefits in 2005 was temporarily increased 8% in the first and second quarters such that 98% of the benefits went to the third parties. In July 2005, a permanent increase in the third-party ownership of the synthetic fuel facilities to 98% was achieved through the sale of an additional 8% interest to a new participant.

Under these third-party ownership transactions, TECO Coal is paid to provide feedstock, operate the synthetic fuel production facilities and sell the output; TECO Coal also recognizes a gain on the sale of the ownership interests in the facilities for each ton of synthetic fuel sold. The purchasers have the risks and rewards of ownership and are allocated 98% of the tax credits and operating costs. The net cash benefit to TECO Coal from the investors for the production of synthetic fuel was approximately $65 million and $158 million in 2006 and 2005, respectively.

TECO Coal has agreements with the investors in its synthetic fuel production facilities that were amended to provide TECO Coal with flexibility to cease producing synthetic fuel. These amendments were entered into in order to provide the parties additional flexibility in the event that high oil prices impact the level of the tax credits. Under the amendments, TECO Coal and the investors will review actual and forecasted oil prices monthly to determine if and at what level synthetic fuel production should continue. If the calendar-year average oil price, on the basis of actual plus futures prices exceed $62 per barrel on the NYMEX basis, TECO Coal has the right to cease or reduce production and the third-party investors have the right to not participate in the production. If production is idled, and oil prices then moderate, full production can resume later in the year.

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 synthetic fuel tax credit is determined annually and is estimated to be $1.21 per million Btu for 2006, and was $1.17 per million Btu in 2005 and $1.13 per million Btu in 2004. This rate escalates with inflation but could be limited by domestic oil prices. TECO Coal has hedged its risk from high oil prices for 2007 (see the discussion above and the **Synthetic Fuel** discussion in the **Outlook** section).

TECO Coal recorded $2.1 million of after-tax benefits from the production associated with its remaining synthetic fuel ownership interest in 2006, but recorded no synthetic fuel tax credits in earnings for 2005 or 2004 because of TECO Energy's actual 2004 and 2005 tax positions, which were driven by tax losses incurred upon the disposition of merchant power plants. In 2004, a $7.0 million positive true-up to income taxes was related to synthetic fuel 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.

TECO Coal Outlook

We expect TECO Coal's Non-GAAP Results Excluding Synthetic Fuel to decline in 2007. Total sales are expected to be in a range between 9 and 9.5 million tons in 2007, which includes 5.7 million tons of synthetic fuel, compared to 9.8 million tons, including 5.3 million tons of synthetic fuel in 2006. The lower expected sales volume reflects the current coal market conditions where inventory accumulation due to mild weather in 2006 and early 2007 has depressed prices for utility steam coal. Excluding synthetic fuel, the average fully-loaded cash and pretax margins per ton are expected to be in line with 2006 margins of about $10 and $6 per ton, respectively.

In January 2007, TECO Coal entered into oil price hedge instruments that protect against the risk of high oil prices reducing the value of the tax credits related to the production of synthetic fuel in 2007. When combined with the hedges entered into in October 2006, the additional instruments protect approximately $195 million of the gross cash benefits expected from the third-party investors for the production of synthetic fuel over the full expected average annual oil price range of $63 to $79 per barrel on a NYMEX basis. The oil price range between $63 and $79 per barrel is the expected phase-out range for synthetic fuel benefits for 2007. The hedges in place provide approximately a dollar-for-dollar recovery of lost synthetic fuel revenues in the event of a phase-out over the estimated phase-out range. The total cost of the hedges was approximately $37 million (see the **Synthetic Fuel** discussion in the **Outlook** section). The value of the hedge instruments may vary during the year, depending on year-to-date actual oil prices plus oil price futures for the remainder of the year, which will be reflected as mark-to-market adjustments in quarterly earnings from synthetic fuel production.

Following the expiration of the synthetic fuel tax credit program on Dec. 31, 2007, we expect both net income and cash flow at TECO Coal to decline 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, and it expects to produce only conventional coal at levels consistent with 2007 in the current market conditions. 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 total 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.

Coal Markets

In 2004 and 2005 the coal industry benefited from higher prices for competing fuels, increased demand worldwide for metallurgical coal, better balance in supply and demand, lower producer and consumer inventories and consolidation in the mining industry all of which contributed to higher prices for coal. 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, and gradual depletion of high-quality Central Appalachian reserves allowed producers to contract production for 2006 at average prices above 2005 average levels.

Following a mild 2006 summer and a mild start to the 2006 – 2007 winter, spot market prices for Central Appalachian utility steam coal have declined more than 40% since the summer of 2006 due to low usage and increased inventories at utility users to above normal levels. A number of Central Appalachian coal producers, including TECO Coal, have announced plans to produce less coal in 2007 in response to the weaker market conditions. Current indications within the domestic coal industry are that until the utility inventories return to more normal levels and supply and demand are balanced there will be few long-term contracts signed for 2008 and beyond and that prices are expected to remain weaker than those experienced in 2005 and 2006.

TECO Coal sells almost all of its annual production under either multi-year contracts or contracts that are finalized late in the previous year or early in the current year. In 2006, TECO Coal benefited from contracts, which included some multi-year contracts, signed in the stronger 2005 price environment. It currently has 86% of its planned 2007 sales under contract with most of the uncontracted tons expected to be sold to European metallurgical coal customers. Contract negotiations with these customers were underway in January and are expected to be completed by the end of the first quarter of 2007 for sales in 2007. Due to its high percentage of coal under contract, TECO Coal expects its average realized price per ton in 2007 to be at levels similar to 2006. For 2008, TECO Coal currently has 45% of its expected sales contracted, all of which is utility steam coal.

The significant factors that could influence TECO Coal's results in 2007 are the higher expected costs of production and the weaker prices for the 14% of production that remains unsold. Longer-term factors that could influence results include inventories at steam coal users, weather, general economic conditions, the level of oil and natural gas prices, commodity price changes which impact the cost of production, and CO_2 reductions if required (see the **Environmental Compliance** and **Risk Factors** sections).

TECO Transport

In 2006, TECO Transport recorded net income of $22.8 million, compared to $20.2 million in 2005. The 2006 results reflected higher river barge rates and equipment utilization, improved oceangoing equipment utilization, lower repair costs at TECO Ocean Shipping, and higher Tampa Electric movements, partially offset by higher fuel costs and lower tonnage for third-party customers. Non-GAAP results of $25.8 million in 2006 excluded $4.5 million of after-tax direct costs associated with damage from Hurricane Katrina at TECO Bulk Terminal and TECO Barge Line, and $1.5 million of after-tax insurance recovery at TECO Barge Line, compared to 2005 non-GAAP results of $19.1 million, which excluded $12.6 million of direct Hurricane Katrina costs and $13.7 million of insurance recovery (see the **2006** and **2005 GAAP to non-GAAP reconciliation** tables). Results in 2006 reflect four oceangoing vessels in international trade which qualified them for the favorable tax treatment of tax law changes under the Jobs Creation Act, which reduces taxes on income earned by U.S.-flag vessels engaged in full-time international trade.

TECO Transport's 2005 net income was $20.2 million, compared to $10.2 million in the same period in 2004. Non-GAAP results in 2005 were $19.1 million, which excluded direct hurricane costs and insurance recovery, compared to $11.9 million in 2004, which excluded management restructuring costs and valuation adjustments on oceangoing equipment. Non-GAAP results in 2005 excluded the $12.6 million after-tax direct costs associated with the restoration and recovery efforts for Hurricane Katrina and the $13.7 million after-tax benefit for insurance recovery related to the hurricane restoration costs at TECO Bulk Terminal (see the **2005 GAAP to non-GAAP reconciliation** table). Results in 2005 were positively affected by the qualification of two oceangoing vessels for the benefits of the tax law changes related to vessels operating in full-time international trade. Results in 2005 were also affected by improved operating efficiencies at TECO Barge Line, higher river barge rates and increased northbound river shipments as well as increased movements of export coal, petroleum coke and other products through TECO Bulk Terminal early in 2005. Higher fuel costs were partially offset by a $3.0 million after-tax benefit from fuel hedges. In 2005, TECO Transport's net income was reduced by an estimated $4.9 million due to the ongoing business interruptions associated with operations at TECO Bulk Terminal as a result of Hurricane Katrina.

In 2005, TECO Bulk Terminal, which is located about 55 miles below New Orleans on the Mississippi River in Davant, Louisiana, was directly in the path of Hurricane Katrina and experienced side effects from Hurricane Rita. Following Hurricane Katrina, the terminal was flooded and without power. There was no damage to the oceangoing fleet and manageable impacts to the river fleet. The more lightly utilized of two cranes that unload in-bound oceangoing vessels was destroyed by the storm. The majority of the river fleet was returned to service and the terminal resumed major operations both in mid-October. Repairs at the terminal continued with near normal river barge unloading achieved in early January 2006. Near normal oceangoing vessel loading operations resumed in early 2006 and major repairs were completed in April 2006.

The river barge industry continues to experience a better balance in supply and demand for river barge services due to improvements in the U.S. economy, increased international movements 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 1980s, 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 increased the cost of construction of replacement barges, have reduced the supply of barges at a time of increasing demand. The improved U.S. economy and the reduced supply of barges is expected to maintain the improved pricing for river barge services in 2007. TECO Barge Line received 50 new river barges in mid-2006 to replace older barges that it retired in 2005 and 2006. It also received an additional 50 new barges starting in February 2007 to replace older barges that it expects to retire in 2007. The new barges received in 2006 and 2007 were chartered under an operating lease.

The demand for non-U.S. flag oceangoing vessels to meet the demand for shipments to China caused rates for these vessels, as measured by the Baltic Dry Index, to climb to a record high in November 2004. These rates have since declined to about 50% of the peak values but they are still more than double the long-term historical levels. 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 create additional opportunities for spot cargo shipments for TECO Transport's oceangoing vessels.

In 2007, TECO Transport expects higher net income from higher oceangoing rates, higher utilization of tonnage tax qualified vessels, improved operating efficiencies at the terminal and increased tonnage through the terminal in Louisiana. TECO Ocean Shipping expects increased shipyard days and associated repair expense due to the normal cycle of regulatory required inspections and repairs.

Future growth at TECO Transport is dependent upon improved pricing, higher asset utilization, and potential asset additions at both the river and oceangoing 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 **Risk Factors** section).

Potential Sale of TECO Transport

In February 2007, we announced that we were considering our options to fund investments in Tampa Electric's growth and to continue our debt retirement plans.

As discussed in the **Overview** section, in 2006, we committed to a plan to retire an additional $500 million of parent debt in the 2008 to 2010 period, beyond the $357 million of parent debt maturing in 2007. We are now exploring our options to meet or exceed our debt retirement goals, and to make additional investments in Tampa Electric to support its growing capital requirements.

At the same time, given the growth opportunities available to TECO Transport, we want to ensure that the business is best positioned to realize its potential in today's transportation market. For this reason, among the alternatives we are considering to address our capital priorities is a review of the options for the long-term future of TECO Transport, including its sale.

We have retained Morgan Stanley to assist in evaluating potential strategic opportunities for TECO Transport. At this early stage in the strategic review process, it is not practical to predict the cash and earnings impacts of actions that might result if a sale were completed (see the **Overview** section).

TECO Guatemala

Our TECO Guatemala operations consist of two non-merchant power plants operating in Guatemala and an ownership interest in Guatemala's largest distribution utility, Empresa Eléctrica de Guatemala (EEGSA). The San José and Alborada power stations in Guatemala both have long-term power purchase contracts. TECO Guatemala's ownership interest in EEGSA is held jointly with partners Iberdrola of Spain and Electricidad of Portugal (EDP) that together own an 81% controlling interest in EEGSA and other affiliate companies in Guatemala. Iberdrola is the operating partner of EEGSA.

The Guatemalan operations are utility-like in nature due to the long-term contracts and stable operations of the power generating facilities. The San José Power Station is a baseload coal-fired station with high capacity and availability factors. In 2005, the San José Power Station supplied approximately 13% of Guatemala's energy needs.

The Alborada Power Station, which consists of oil-fired, simple-cycle combustion turbines, is a peak-load facility with high availability, but low capacity factor by design. Guatemala is heavily dependent on hydro-electric sources for power generation. Seasonally or in periods of low rainfall, the Alborada Power Station will operate more.

TECO Guatemala had net income of $37.6 million in 2006, compared to $40.4 million in 2005, which was driven by 4.3% customer growth at EEGSA, 3% higher generation at the San José Power Station, higher capacity payments at the Alborada Power Station, lower insurance and interest expense, and operating and maintenance expenses essentially unchanged from 2005 levels more than offset by a higher tax rate. Results in 2005 included the one-year benefit of the 5% tax rate on dividends under the Jobs Creation Act, while 2006 reflects the normal 35% tax rate.

Net income for TECO Guatemala in 2005 was $40.4 million, compared to $5.7 million in 2004, which included a $6.7 million after-tax charge related to debt extinguishment, $17.4 million of taxes on repatriated cash, and a $12.8 million after-tax write-off of unused steam turbines. Although it is included in the TECO Guatemala segment for accounting purposes due to the redefining of our segments, the 2004 steam turbine write-off was not directly related to the Guatemalan operation; it related to turbines purchased in anticipation of a non-merchant project for TWG Merchant that was terminated. The 2005 results reflect higher operations and maintenance expenses early in the year and somewhat higher tax rates, partially offset by energy sales and customer growth at EEGSA and higher non-fuel revenues for the power plants.

At TECO Guatemala, we expect 2007 net income consistent with the strong 2006 levels. We expect continued strong operations and sales at the power plants and EEGSA. At San José, we expect to benefit from lower interest rates and from the lower principal balance on the non-recourse debt. At EEGSA, we expect flat results as continued customer and energy sales growth will be essentially offset by lower transmission wheeling revenues. Customer and energy sales growth are expected to be 3.5% and 1%, respectively, in 2007. We also expect benefits and other costs to be higher.

The Comisión Nacional de Energia Eléctrica (CNEE) was created under the General Electricity Law of 1996 as a branch of the Ministry of Energy and Mines in Guatemala and regulates the energy sector in Guatemala. EEGSA expects to undergo a new rate case process and renegotiation of the Value Added Distribution (VAD) charge applicable in the tariffs, leading up to new rates effective in May 2008. The new VAD rates that EEGSA can charge its customers for the use of its distribution lines will be set for a term of five years. The current VAD rates were established in May 2003. The Ministry of Energy and Mines and the CNEE are also in the midst of a review of the existing electricity regulations for the country. TECO Guatemala personnel are monitoring and participating in this process.

Parent/Other

In 2006, the Parent/Other cost was $60.4 million, compared to $127.1 million in 2005. In 2006, the Parent/other non-GAAP cost was $74.2 million, compared to $80.4 million in 2005. 2006 Non-GAAP results in Parent/Other excluded the $8.1 million after-tax gain on the sale of the remaining assets of the unfinished McAdams Power Station, which had been previously impaired, and $5.7 million of after-tax gains on unused steam turbines that had been previously impaired. Non-GAAP results in 2005 excluded $46.7 million of after-tax charges associated with the early retirement of debt (see the **2005** and **2006 GAAP to non-GAAP reconciliation** tables). These results were driven by pretax parent interest expense which was $18.1 million lower in 2006 due to the debt redemption and refinancing actions initiated in mid-2005. This was offset, in part, by no longer allocating interest to TWG Merchant. Parent interest allocated to the operating companies was $23.1 million in 2006, compared to $36.2 million in 2005. Investment income on cash and short-term investments increased $6.6 million over 2005 as a result of higher interest rates and higher investment balances.

We expect costs at TECO Energy parent to decline in 2007 due to the retirement of the remaining $100 million of 8.5% trust preferred securities in December 2006; the repayment of the $57 million of 5.93% junior subordinated notes, which was completed in January 2007; and the repayment of the $300 million of 6.125% notes maturing in May 2007. Investment income is expected to decline due to lower cash balances as debt is retired.

TWG Merchant

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. In 2005, we essentially completed our exit from the merchant power business and the sales of the minor remaining assets were completed in 2006 (see the **Overview** section).

In 1999, we announced that a component of our strategy was to expand our presence in the domestic independent energy industry. Our decision to invest in this industry was based on the outlook at that time for the energy markets beyond 2001, and the expectation that there would be wide-spread deregulation of these markets. Starting in late 2001 and early 2002, after we had committed to the major investments in unregulated power, conditions in energy markets changed. 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. In addition, the large amount of new generating capacity which came online in 2002 and 2003 contributed to significant excess generating capacity in many areas of the country and thus lower wholesale power prices.

These changed market conditions and the prospects for operating losses and negative cash flow at most of the merchant facilities we were constructing for several years, caused us to delay some projects and sell others commencing in 2003.

In 2004 and 2005, we took aggressive actions to complete our exit from the merchant power business. We completed the sale and transfer of the ownership of the Union and Gila River projects to the lenders; we sold our interests in the remaining operating projects and the uncompleted Dell Power Station. In 2005, we announced our decision to terminate the uncompleted McAdams Power Station and to transfer combustion turbines from that project to Tampa Electric in 2006 to meet its peaking generation needs. In 2006, we completed the sale of the remaining assets associated with the McAdams Power Station.

Liquidity, Capital Resources

The table below sets forth the Dec. 31, 2006 consolidated liquidity and cash balances, the cash balances at the operating companies and TECO Energy parent, and amounts available under the TECO Energy and Tampa Electric credit facilities.

(millions)	*Consolidated*	*Tampa Electric*	*Other*	*Parent*
Credit facilities	$ 675.0	$475.0	$ —	$200.0
Drawn amounts/Letters of credit	57.5	48.0	—	9.5
Available credit facilities	617.5	427.0	—	190.5
Cash	441.6	5.1	34.2	402.3
Total liquidity	$1,059.1	$432.1	$34.2	$592.8
Consolidated restricted cash (not included above)	$ 37.3	$ —	$30.2	$ 7.1

Consolidated restricted cash of $37.3 million includes $30.0 million held in escrow until early 2008 related to the sale of an interest in the synthetic coal production facilities. In addition to consolidated cash, as of Dec. 31, 2006, unconsolidated affiliates owned by TECO Guatemala, CGESJ (San José) and TCAE (Alborada), had unrestricted cash balances of $18.7 million and restricted cash of $8.2 million, which are not included in the table above, as these project companies were deconsolidated due to the adoption of FIN 46R, *Consolidation of Variable Interest Entities*, effective Jan. 1, 2004.

In 2006, we met our cash needs from a mix of internal sources, asset sales and long-term notes issued at Tampa Electric Company. Cash from operations was $567 million in 2006. Other sources of cash in 2006 included $123 million of proceeds from third-party investors for ownership interests in TECO Coal's synthetic fuel production facilities, $250 million from the issuance of long-term debt at Tampa Electric, and $42 million from the sale of the land at TECO Properties and the remaining merchant power and energy services assets. We used cash to retire the remaining $100 million of 8.5% trust preferred securities outstanding prior to maturity, and the regulated companies reduced short-term borrowings $167 million. We paid dividends in 2006 of $159 million on TECO Energy common stock. Our capital expenditures for the year were $456 million.

In 2005, we met our cash needs from a mix of internal sources, asset sales and short-term borrowings under Tampa Electric Company's credit facilities. Cash from operations was $177 million in 2005. Other sources of cash in 2005 included $206 million of proceeds from third-party investors for ownership interests in TECO Coal's synthetic fuel production facilities, $180 million from the final settlement of the 9.5% adjustable conversion-rate equity security units, $300 million from the issuance of long-term debt, regulated short-term borrowings of $100 million and $165 million from the sale of the Commonwealth Chesapeake and Dell power stations. We utilized the proceeds from the long-term debt issuance in combination with cash on hand to retire prior to maturity $480 million of our highest-cost debt. We paid dividends in 2005 of $158 million on TECO Energy common stock. Our capital expenditures for the year were $295 million, and we paid $32 million to the lenders upon the final transfer of the Union and Gila River power stations.

In 2006 the impact of discontinued operations on cash from operations was not material. In 2005 and 2004, consolidated cash from operations included the cash operating losses from the Union and Gila River power stations that were in discontinued operations prior to the final transfer to the lenders in May 2005. Consolidated cash was not affected by these losses since investing activities included an offsetting source of cash that was included as restricted cash at the project companies.

Cash from Operations

In 2006, consolidated cash flow from operations was $566.9 million, which included, among normal operating items, net cash of $53.4 million reflecting the FPSC-approved recovery of previously under-recovered 2005 fuel costs, which was partially offset by the credit on customers' bills related to Tampa Electric's sale of $45 million of excess SO_2 emissions credits. In addition, cash from operations reflects a $30 million early contribution to the pension plan in 2006. The accounting treatment of the sale of interests in the synthetic fuel production facilities at TECO Coal includes the costs associated with synthetic fuel production in cash flow from operations, but the proceeds from the third-party synthetic fuel investors are reported as cash from investing and financing activities.

In 2004 and 2005, TECO Coal sold a total of 98% of the ownership interests in its synthetic fuel production facilities to third-party investors. In 2006, cash flow from operations includes the operating losses of approximately $11 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 $33 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, which was reduced as a result of high oil prices in 2006 (see the **TECO Coal** section). 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.

We expect cash from operations to increase in 2007 from improved operating results, collection by Tampa Electric of its remaining under-recovered fuel expense from 2005 and 2006, and lower interest expense due to the retirement of $100 million of parent debt in 2006 and the retirement of $357 million of parent debt in 2007 (see the **Cash and Liquidity Outlook** section).

We made the minimum required contributions to our pension plan in 2006 and 2005 of $6 million and $17 million, respectively. In November 2006, we made a voluntary and previously unplanned $30 million contribution to the plan to accelerate improvement in the plan's funded status. We plan to also contribute $30 million in 2007, which is above the minimum amount required. We estimate that our contribution will average about $22 million annually in 2008 through 2011 (see **Note 5** to the TECO Energy **Consolidated Financial Statements**).

Cash from Investing Activities

Our investing activities in 2006 resulted in a net use of cash of $352 million, including, among other items, capital expenditures totaling $456 million and net asset sale proceeds of $10 million. Asset sales included $8 million from the sale of two unused steam turbines remaining from the TWG Merchant operations, $10 million from the sale of a district cooling plant in Miami, $57 million from the sale of the 98% ownership interests in TECO Coal's synthetic fuel facilities, $15 million from the sale of land and $7 million from the sale of marine transportation equipment no longer used by TECO Transport.

We expect capital spending for the next several years to be higher, primarily at Tampa Electric. Our capital spending forecast currently does not include amounts for Tampa Electric's next baseload generating capacity addition, which is expected to be required in early 2013 (see the **Tampa Electric** and **Capital Expenditures** sections).

We have completed our disposition of merchant and energy services assets, and do not anticipate significant additional proceeds from sales of this nature. Proceeds from investors in the synthetic fuel production facilities will conclude after 2007 when the non-conventional fuels tax credit program expires.

Cash from Financing Activities

Our financing activities in 2006 resulted in net use of cash of $119 million. Major items included the early retirement of $100 million of the remaining 8.5% TruPS securities outstanding, Tampa Electric's issuance of $250 million of long-term notes (see the **Financing Activity** section) and $167 million reduction of short-term borrowings, and $159 million in common stock dividends. In addition, we received $66 million for providing the feedstock and reimbursement of the operating costs of TECO Coal's synthetic fuel production facilities in the form of minority interest payments from the third-party owners.

In 2007, we retired the $57 million of junior subordinated notes due Jan. 16 and we plan to retire the $300 million of notes maturing in May. In 2007, Tampa Electric Company expects to refinance $150 million of notes maturing in August and utilize short-term borrowings under its credit facilities to support its capital spending program and for normal working capital fluctuations. TECO Transport is considering options for its $110 million of tax-exempt dock and wharf bonds that mature in September, including either refinancing or retirement. See the **Cash and Liquidity Outlook** section below for a discussion of financing expectations beyond 2007.

Cash and Liquidity Outlook

In general, we target consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of approximately $500 million, comprised of $300 million for Tampa Electric Company and $200 million for TECO Energy. In 2006, because we accumulated cash in excess of our general targets for the planned retirement of $357 million of maturing TECO Energy parent notes in 2007, at Dec. 31, 2006 our consolidated liquidity was $1,059 million. Of this total, Tampa Electric had total liquidity of $432 million. TECO Energy parent had total liquidity of $593 million. The consolidated unregulated operating companies had $34 million of unrestricted cash. In addition, there was $19 million of unrestricted cash at the unconsolidated operating companies.

We currently forecast our 2007 consolidated cash flow from operations to be approximately $660 million and expect a consolidated net use of cash of approximately $160 million after dividends. Our forecast of cash from operations includes recovery in 2007 of approximately $123 million of 2005 and 2006 net fuel and other clause under-recoveries at Tampa Electric. Cash flow from operations includes the projected $58 million cost of producing synthetic fuel for the full year, but excludes the projected $195 million of synthetic fuel investor proceeds, as these proceeds are reported in cash from investing and financing activities. The forecast of consolidated net cash generation assumes estimated capital expenditures of approximately $523 million, net Tampa Electric Company borrowing of approximately $60 million, the $29 million we spent in January 2007 for oil price hedge instruments and the repayment of the $357 million of TECO Energy parent notes maturing in 2007.

This forecast assumes that there is no reduction in proceeds that would occur if oil prices exceed the threshold level at which the synthetic fuel tax credits would begin to be reduced (see the **Synthetic Fuel** discussion in the **Outlook** section). If oil prices exceed the phase-out threshold, the oil price hedge instruments become the source of cash and replace lost investor proceeds. However, the cash from the hedges would be received in early 2008 rather than in 2007. Our forecast also does not include the potential sale of TECO Transport, which we would expect to provide cash to meet our parent-level debt retirement goals earlier than currently forecast (see the **Overview** and **TECO Transport** sections).

We expect TECO Energy parent to have net use of cash of approximately $180 million after dividends in 2007. This forecast is based on the assumptions described above and also assumes that we make an $80 million equity contribution to Tampa Electric and pay common stock dividends at current levels.

TECO Energy plans to reduce parent debt levels by an additional $500 million in the 2008 through 2010 period and does not expect to access the capital markets until such time as it seeks to refinance any of its notes maturing in 2010 through 2012 that would remain outstanding after its $500 million of repayments and any additional repayments that we elect to make. Tampa Electric Company expects to access the debt capital markets for long-term debt to refinance existing debt and to support its capital spending program, and expects to utilize its credit facilities for normal working capital fluctuations.

Our expected cash flow could be affected by variables discussed in the individual operating company sections, such as customer growth and usage changes at our regulated businesses, coal production levels and coal sales prices. In addition, actual fuel and other regulatory clause net recoveries will typically vary from those forecasts; however, these differences are generally recovered within the next calendar year. It is possible however, 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 future TECO Energy parent debt maturities (see the **Risk Factors** section).

Higher expected capital expenditures at Tampa Electric over the next several years are expected to require additional equity contributions from TECO Energy in order to maintain the utility capital structure and financial integrity. Tampa Electric expects to fund approximately 50% of its capital needs with internally generated cash and external borrowing. If a sale of TECO Transport is completed, we would expect to use proceeds for the early implementation of our parent debt retirement plans in the 2008 through 2010 period. This would position us to redeploy cash that was planned for debt retirement in those years to Tampa Electric in the form of parent equity contributions to fund its generation expansion and other capital needs.

Credit Facilities

At Dec. 31, 2006 and 2005, the following credit facilities and related borrowings existed:

		December 31, 2006			*December 31, 2005*		
		Credit Facilities	*Borrowings Outstanding*	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*	*Letters of Credit Outstanding*
Tampa Electric	5-year facility	**$325.0**	**$13.0**	**$ —**	$325.0	$120.0	$ —
	1-year accounts receivable facility	**150.0**	**35.0**	**—**	150.0	95.0	—
TECO Energy	5-year facility	**200.0**	**—**	**9.5**	200.0	—	14.3
Total		**$675.0**	**$48.0(1)**	**$9.5**	$675.0	$215.0(1)	$14.3

(1) Borrowings outstanding are reported as notes payable.

These credit facilities require commitment fees ranging from 12.5 to 37.5 basis points. The weighted average interest rate on outstanding notes payable under the credit facilities at Dec. 31, 2006 and 2005 was 5.45% and 4.45%, respectively.

At Dec. 31, 2006, TECO Energy had a bank credit facility in place of $200 million with a maturity date of October 2010, and Tampa Electric Company had a bank credit facility totaling $325 million, also maturing in October 2010. In addition, Tampa Electric Company had a $150 million accounts receivable securitized borrowing facility. The TECO Energy and Tampa Electric Company bank credit facilities include sub-limits for letters of credit of $100 million and $50 million, respectively. The TECO Energy facility was undrawn at Dec. 31, 2006, except for $9.5 million of outstanding letters of credit. At Dec. 31, 2006, $48 million was drawn on the Tampa Electric Company credit facilities.

Our $200 million credit facility, which was amended and extended to its current maturity in October 2005, 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 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).

At current ratings, TECO Energy's and Tampa Electric Company's bank credit facilities require commitment fees of 37.5 basis points and 12.5 basis points, respectively, and drawn amounts are charged interest at LIBOR plus 125 – 150 basis points and 52.5 – 65.0 basis points, respectively. At Dec. 31, 2006, the LIBOR interest rate was 5.32%.

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 collateralized borrowing facility. Under this facility, Tampa Electric Company sells and/or contributes to TRC all of its receivables for the sale of electricity or gas to its customers and related rights. The receivables are sold by Tampa Electric Company to TRC at a discount, which was initially 2%. The discount is subject to adjustment for future sales to reflect changes in prevailing interest rates and collection experience. TRC is consolidated in the financial statements of Tampa Electric Company 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 secures such borrowings with a pledge of all of its assets, including the receivables. Tampa Electric Company acts as the servicer to service the collection of the receivables. TRC pays program and liquidity fees based on Tampa

Electric Company's credit ratings, which total 35 basis points at its current ratings. Interest rates on the borrowings are 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: (1) at each quarter-end, Tampa Electric Company's debt-to-capital ratio, as defined in the agreement, must not exceed 65%; and (2) certain dilution and delinquency ratios with respect to the receivables. At Dec. 31, 2006, the interest rate for borrowings under the Tampa Electric accounts receivable facility was 5.33%

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. At Dec. 31, 2006, TECO Energy, Tampa Electric Company, and the other operating companies were in compliance with all required financial covenants. The table that follows lists the significant financial covenants and the performance relative to them at Dec. 31, 2006. 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, 2006*
Tampa Electric Company			
PGS senior notes	EBIT/interest[2]	Minimum of 2.0 times	3.1 times
	Restricted payments	Shareholder equity at least $500	$1,714
	Funded debt/capital	Cannot exceed 65%	51.6%
	Sale of assets	Less than 20% of total assets	0%
Credit facility[3]	Debt/capital	Cannot exceed 65%	51.3%
Accounts receivable credit facility[3]	Debt/capital	Cannot exceed 65%	51.3%
6.25% senior notes	Debt/capital	Cannot exceed 60%	51.3%
	Limit on liens[5]	Cannot exceed $701	$201 liens outstanding
Insurance agreement relating to pollution bonds	Limit on liens[5]	Cannot exceed $358 (7.5% of net assets)	$0 liens outstanding
TECO Energy			
Credit facility[3]	Debt/EBITDA[2]	Cannot exceed 5.25 times	4.1 times
	EBITDA/interest[2]	Minimum of 2.60 times	3.5 times
	Limit on additional indebtedness	Cannot exceed $228	$0
	Dividend restriction[4]	Cannot exceed $50 per quarter	$40
$300 million note indenture	Limit on liens[5]	Cannot exceed $299 (5% of tangible assets)	$0 outstanding
$100 million and $200 million note indentures	Restrictions on secured debt	(6)	(6)
TECO Diversified			
Coal supply agreement guarantee	Dividend restriction	Net worth not less than $414 (40% of tangible net assets)	$567

(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 to the TECO Energy Consolidated Financial Statements.

(4) TECO Energy cannot declare quarterly dividends in excess of the restricted amount unless liquidity projections, demonstrating sufficient cash or cash equivalents to make each of the next three quarterly dividend payments, are delivered to the Administrative Agent.

(5) If the limitation on liens is exceeded the company is required to provide ratable security to the holders of these notes.

(6) The indentures for these notes contain restrictions which limit secured debt of TECO Energy if secured by Principal Property or Capital Stock or indebtedness of directly held subsidiaries (with exceptions as defined in the indentures) without equally and ratably securing these notes.

Credit Ratings of Senior Unsecured Debt at Dec. 31, 2006

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

All three credit rating agencies have assigned stable outlooks to our ratings. In February 2007, Moody's Investor Service affirmed the rating of Tampa Electric Company and placed TECO Energy ratings on review for possible upgrade.

Standard & Poor's, Moody's and Fitch describe credit ratings in the BBB or Baa category as representing adequate capacity for payment of financial obligations. The lowest investment grade credit ratings for Standard & Poor's is BBB-, for Moody's is Baa3 and for Fitch is BBB-; thus all three credit rating agencies assign Tampa Electric Company's senior unsecured debt investment grade ratings. The ratings assigned by all three rating agencies to TECO Energy and TECO Finance are below investment grade.

A credit rating agency rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the assigning rating agency. Any future downgrades in credit ratings may affect our ability to borrow and may increase financing costs, which may decrease earnings (see **Risk Factors** section).

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.

Contractural Cash Obligations at Dec. 31, 2006

(millions)			*Payments Due by Period*			
	Total	*2007*	*2008*	*2009*	*2010-2011*	*After 2011*
Long-term debt (1)						
Recourse	$3,772.3	$ 566.7	$ 5.7	$ 5.5	$1,007.1	$2,187.3
Non-recourse(2)	11.7	1.3	1.4	1.4	2.9	4.7
Junior subordinated notes(3)	71.4	71.4	—	—	—	—
Operating leases/rentals (4)	188.6	28.0	21.2	18.7	33.4	87.3
Net purchase obligations/commitments (4) (5)	402.8	194.0	56.4	37.8	55.6	59.0
Interest payment obligations(6)	1,894.2	237.5	213.0	212.5	358.7	872.5
Pension plan(7)	96.0	0.6	19.8	20.7	42.5	12.4
Total contractual obligations	$6,437.0	$1,099.5	$317.5	$296.6	$1,500.2	$3,223.2

(1) Includes debt at TECO Energy, Tampa Electric, Peoples Gas and the other operating companies (see **Note 7** to the TECO Energy **Consolidated Financial Statements** for a list of long-term debt and the respective due dates).

(2) Reflects an intercompany loan at TECO Guatemala between its consolidated Cayman Island entity and an unconsolidated Guatemalan affiliate.

(3) These notes were retired on Jan. 16, 2007 as required.

(4) Excludes TECO Transport's outstanding commitment of $21 million for the construction of 50 replacement river barges, as the company is chartering these barges under an operating lease signed Feb. 16, 2007.

(5) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2006, these commitments included Tampa Electric's outstanding commitments of about $371 million primarily for materials and contracts related to the NO_x control equipment and long-term capitalized maintenance agreements for its combustion turbines.

(6) Includes variable rate notes at interest rates as of Dec. 31, 2006. Included in 2007 interest payments is $1.1 million related to the $71.4 million of 5.93% junior subordinated notes (see **Note 22** to the TECO Energy **Consolidated Financial Statements**) and $7.7 million of interest payments related to the planned retirement of the $300 million of 6.125% notes due in May 2007.

(7) The total includes the estimated minimum required contributions to the qualified pension plan as of the measurement date. Future contributions are included but 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 **Liquidity, Capital Resources – Cash from Operations** section and **Note 5** to the TECO Energy **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. These amounts represent guarantees by TECO Energy on behalf of consolidated subsidiaries. TECO Energy has no guarantees outstanding on behalf of unconsolidated or unrelated parties.

Contingent Obligations at Dec. 31, 2006

				Commitment Expiration			
(millions)		*Total(2)*	*2007*	*2008*	*2009*	*2010 - 2011*	*After 2011*
Letters of credit (1)		$ 9.5	$ —	$ —	$ —	$ —	$ 9.5
Guarantees	Fuel/power purchases	67.7	43.7	—	—	—	24.0(3)
	Other	1.4	—	—	—	—	1.4
Total contingent obligations		$78.6	$43.7	$ —	$ —	$ —	$34.9

(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 Expenditures

(millions)	***Actual 2006***	*Forecast 2007*	*2008*	*2009-2011*	*2007-2011 Total*
Tampa Electric					
Transmission	**$ 21**	$ 21	$ 59	$ 173	$ 253
Distribution	**95**	118	145	440	703
Generation	**96**	109	63	257	429
Generation expansion (1)	**57**	6	—	—	6
Other	**20**	25	31	75	131
NO_x control projects	**67**	87	72	54	213
Other environmental	**7**	34	26	71	131
Tampa Electric total	**363**	400	396	1,070	1,866
Peoples Gas	**54**	50	50	150	250
TECO Coal	**40**	45	40	98	183
TECO Transport	**17**	25	23	77	125
TECO Guatemala(2)	—	3	—	—	3
Other	**(20)**	—	—	—	—
Total	**$454**	$523	$509	$1,395	$2,427

(1) Except for the amounts shown in 2007 for completion of two peaking units, this forecast excludes capital expenditures for new generating capacity that is expected to be needed in the 2009 – 2012 period. See the discussion below and the Tampa Electric section.

(2) Represents only the capital expenditures of the consolidated operations of TECO Guatemala. Under FIN 46R the major operations of TECO Guatemala are unconsolidated, and the related capital expenditures are not included in this table.

TECO Energy's 2006 capital expenditures of $454 million (without reduction for asset and business sale proceeds) included $363 million, excluding Allowance for Funds Used During Construction (AFUDC), for Tampa Electric and $54 million for PGS. Tampa Electric's capital expenditures in 2006 were primarily for equipment and facilities to meet its growing customer base, generating equipment maintenance, capital expenditures required for additional generating capacity in the form of two peaking units and environmental compliance including $67 million for NO_x control projects (see the Environmental Compliance section). Capital expenditures for PGS were approximately $36 million for system expansion and approximately $18 million for maintenance of the existing system. TECO Coal's capital expenditures included $22 million primarily for normal mining equipment replacement, $6 million for new mine development and $12 million for equipment to improve recoveries of coal from two coal-preparation plants. TECO Transport invested $17 million in 2006, including $14 million for normal steel replacements and shipyard periods for oceangoing vessels, and $3 million of capitalized repairs at its terminal in Louisiana for Hurricane Katrina-related damage repairs. The $(20) million amount in the "Other" category represents the purchase of two combustion turbines from the unfinished TWG Merchant McAdams Power Station, which are included in Tampa Electric's capital expenditures.

TECO Energy estimates capital spending for ongoing operations to be $523 million for 2007 and approximately $1.9 billion during the 2008 – 2011 period.

For 2007, Tampa Electric expects to spend $400 million, consisting of about $235 million to support system growth and generation reliability, which includes $13 million for transmission and distribution system storm hardening and $4 million for new high-voltage transmission system improvements to meet reliability requirements. In addition, Tampa Electric expects to spend $16 million for an additional natural gas pipeline to improve reliability of supply to the Bayside Power Station, $20 million for coal-fired generation capacity factor and availability improvements, $6 million to complete the addition of two combustion turbines at the Polk Power Station to meet its peaking generation capacity needs, $87 million for the addition of SCR equipment at the Big Bend Station for NO_x control, and $34 million for other environmental compliance programs in 2007.

Tampa Electric's total capital expenditures over the 2008 – 2011 period are projected to be $1,466 million, excluding its next baseload generating capacity addition which is currently expected to be required in early 2013 or any peak load generating capacity additions required in the 2009 – 2012 period. After the initial ramp-up in spending on the required transmission system improvements and storm hardening in 2007, Tampa Electric expects to spend approximately $300 million annually to support normal system growth and reliability. This increased level of ongoing capital expenditures reflects the general higher costs for materials and contractors, new long-term regulatory requirements for storm hardening, and an active program of transmission and distribution system upgrades which will occur over the forecast period. These new programs and requirements include: approximately $30 million annually for repair and refurbishments of combustion turbines under long-term agreements with equipment manufacturers; $20 million annually for transmission and distribution system storm hardening; approximately $35 million annually for transmission and distribution system reliability and capacity improvements; and an average of $25 million annually for high-voltage transmission system improvements to meet NERC reliability requirements in Central Florida. In addition to the $300 million of ongoing annual capital expenditures, Tampa Electric expects to spend $127 million for compliance with the Environmental Consent Decree for the SCR equipment and $97 million for other required environmental capital expenditures in the 2008 – 2011 period. The Environmental Consent Decree 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 $50 million in 2007 and $200 million during the 2008 – 2011 period. Included in these amounts is an average of approximately $33 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 expects to invest $40 million in 2007 and $143 million during the 2008 – 2011 period. Included in these amounts are new mine development projects to replace higher cost of production mines and position TECO Coal to increase production when coal markets improve. Also included is normal renewal and replacement capital, including coal mining equipment. TECO Transport expects to spend $17 million in 2007 and $108 million during the 2008 – 2011 period primarily for normal steel replacements and shipyard periods for oceangoing vessels and inland river transportation equipment. TECO Coal had outstanding commitments of approximately $27 million, primarily for replacement of coal mining equipment at Dec. 31, 2006. TECO Transport had an outstanding commitment of $21 million for the construction of 50 replacement river barges, which is not included in the capital spending forecast. In February 2007, TECO Barge Line amended an existing charter agreement to include these 50 replacement river barges (see the footnotes to the **Contractual Cash Obligation** table and the **Financing Activity** section).

The forecast capital expenditures shown above are based on our current estimates and assumptions for normal maintenance capital at the operating companies; capital expenditures to support normal system growth at Tampa Electric and PGS (excluding new generating capacity at Tampa Electric); the new programs for transmission and distribution system storm hardening and new transmission system reliability requirements; and incremental investments above normal maintenance capital to expand the PGS system and capacity at TECO Coal. Actual capital expenditures could vary materially from these estimates due to changes in costs for materials or labor or changes in plans (see the Risk Factors section).

Tampa Electric Future Generating Capacity Additions

The above forecasted amounts do not include any expenditures for Tampa Electric's next baseload generating capacity addition, which, based on its current forecast of energy demand and sales growth, is expected to be required in early 2013, or any peak load generating capacity additions required in the interim period. Tampa Electric's options to satisfy the generating capacity needs range from purchasing the power to constructing its own generating facilities. Tampa Electric has initiated a RFP for incremental peak capacity needs it projects to have in the 2009 – 2012 period, and, as required in Florida for baseload capacity additions, to potentially purchase the needed power under power purchase agreements. If construction of generating capacity by Tampa Electric, including a baseload unit, is found to be the most cost-effective method of meeting customers' needs, there are additional regulatory and permitting steps required prior to Tampa Electric moving forward with such a construction program for the baseload capacity. The RFP process and the regulatory approval process for baseload generating capacity are expected to be completed in late 2007.

The capital expenditures required under the various options currently being evaluated vary significantly from only transmission system improvements to allow the import of power to construction of peaking capacity and baseload capacity. In addition to an evaluation of the purchase versus build option, Tampa Electric has options regarding the type of baseload plant to be constructed ranging from natural gas-fired combined cycle to an Integrated Gasification Combined Cycle (IGCC) unit. Tampa Electric's preferred option is a 630-megawatt, coal- and petroleum coke-fueled IGCC unit in order to meet the State of Florida's goal of diversifying the fuel supplies used to generate power, and the ability to more easily capture and sequester CO_2 emissions if required in the future (see the **Environmental Compliance** section). Capital expenditures to meet Tampa Electric's peaking and baseload capacity needs are estimated to be in excess of $1.5 billion, excluding AFUDC, starting in 2008, peaking in 2010 and ending in 2013.

In 2006, the Florida Legislature enacted a new statute related to new nuclear plants that might be constructed in Florida that provided for, among other things, the recovery of pre-construction costs and carrying costs of construction through the capacity cost recovery clause; a base rate increase when the plant is put in service to recover the costs of the plant; and the recovery of prudently incurred costs in the event that the plant is not completed. Tampa Electric is seeking similar legislative treatment for IGCC plants as they accomplish the same goal of increasing fuel diversity in Florida.

Financing Activity

Our 2006 year-end capital structure was 68.0% senior debt, 1.3% junior subordinated debt, and 30.7% common equity. The debt-to-total-capital ratio improved from last year, primarily due to the December 2006 call and retirement of the remaining junior subordinated notes related to our 8.5% TruPS of TECO Capital Trust I.

In 2006, we issued no new debt at the TECO Energy parent level. We did raise a small, recurring amount of equity primarily through our dividend reinvestment plan. Tampa Electric refinanced $86 million of 6.25% tax-exempt bonds to an auction-rate mode, on which the average interest rate was 3.25% in 2006. Tampa Electric also issued $250 million of 30-year notes at 6.55%. The proceeds of this issuance were used to retire short-term borrowings under Tampa Electric's credit facilities, for working capital needs and to support its capital spending program.

In April 2006, TECO Barge Line entered into a 15 year charter agreement for the lease of 50 newly constructed river barges to replace barges that had either already been retired or were scheduled for retirement. In February 2007, the charter agreement was amended to include an additional 50 newly constructed replacement river barges.

In 2005, as part of our overall efforts to manage our debt and reduce interest expense, we accessed the debt markets for new capital on two occasions for $200 million of fixed-rate notes and $100 million of floating-rate notes. The proceeds from the fixed-rate notes, together with cash on hand, were used to retire in full the $380 million aggregate principal amount outstanding of our 10.5% notes due 2007. The floating-rate notes were issued to provide us the increased financial flexibility to call and retire $100 million, or 50%, of our 8.5% TruPS of TECO Capital Trust I. In addition, Tampa Electric used short-term borrowings under its credit facilities for working capital needs, which included temporarily under-recovered fuel costs, and to support its environmental capital spending program.

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 the retirement of $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 remained outstanding at Dec. 31, 2006, including the 3% ($14 million) held by TECO Capital Trust II. These securities, which had a coupon rate of 5.93% set in the remarketing, were repaid at maturity in January 2007. The proceeds from the remarketing were used by the trustee to purchase a portfolio of U.S. 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 financings beginning in 2004.

Date	*Security*	*Company*	*Net proceeds/ facility size*	*Coupon*	*Use*
May 2006	30-year notes	Tampa Electric	$250	6.55%	Repay short-term debt and general corporate purposes
Jan. 2006	Tax-exempt bonds due 2034	Tampa Electric	$ 86 (2)	Auction rate mode	Refinance existing bonds
Oct. 2005	Credit facility	TECO Energy	$200	—	5-year facility
Oct. 2005	Credit facility	Tampa Electric	$325	—	5-year facility
Jun. 2005	5-year notes	TECO Energy	$100	Floating rate	Initiate debt redemption program
May 2005	10-year notes	TECO Energy	$200	6.75%	Initiate debt redemption program
Jan. 2005	Common equity	TECO Energy	$180 (1)	—	Final settlement of equity security units
Jan. 2005	Credit facility	Tampa Electric Company	$150	—	Accounts receivable facility with annual renewal
Oct. 2004	Trust preferred securities	TECO Energy	$ 71.4 (2)	5.93%	Required TECO Capital Trust II remarketing
Aug. 2004	Common equity	TECO Energy	$ 0 (3)	—	Early settlement of equity security units

(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-Balancing Sheet Financing

Unconsolidated affiliates have project debt balances as follows at Dec. 31, 2006. The two power plant financings are non-recourse project loans, and the debt associated with EEGSA is general corporate debt at EEGSA; all of this debt is held at the project entity level. 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 interest and principal payments on these loans are not made timely. Our investment in TECO Guatemala was $401.5 million at Dec. 31, 2006.

Off-Balance Sheet Debt at Dec. 31, 2006

(millions)	*Long-term Debt*	*TECO Guatemala's Ownership Interest*
San José Power Station	$ 85.3	100%
Alborada Power Station	$ 13.0	96%
EEGSA	$226.3	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.

We deconsolidated the project entities for 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 TECO Energy 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 TECO Energy **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.

Synthetic Fuel and Section 29 Tax Credits

The company earns income indirectly through the production of synthetic fuel at TECO Coal. TECO Coal sold its ownership interests in the synthetic fuel facilities to third-party investors based on the amount of future production and the resulting gains are adjusted by the estimated value of the tax benefits provided under Section 45 (formerly Section 29) of the tax code. The tax credit begins to phase out when the average annual oil price exceeds a reference price, which was estimated to $62.00/ Bbl on a NYMEX basis in 2006. The final determination of the actual 2006 reference price and any resulting phase-out of the tax credit benefits will not be made by the Internal Revenue Service until March of 2007, as a result management is required to estimate the potential phase-out and adjust the payments expected for the sale of the ownership interests accordingly. At the end of 2006, the annual average oil price was calculated to be $65.90 on a NYMEX basis. Based on this average, a 90% actual Producer First Purchase Price to NYMEX adjustment factor and a 3.08% inflation rate, the phase-out was estimated to be 35%, resulting in a reduction in revenues from the third-party investors of $61.1 million on $174.5 million in sales.

The company has also determined that a 0.25% increase in inflation would result in a reduction of 1.03% in the amount of the phase-out, which would result in a $1.2 million pretax reduction in revenue from the third-party investors. The actual final inflation rates will be known in late March or early April. Any adjustments to 2006 earnings as a result of changes in the inflation rate will be reflected in 2007's results. The payments received for the sale of the synthetic fuel ownership interests are reflected as other income and minority interest classifications in the income statement.

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, 2006, we had net deferred income tax assets of $630.2 million, attributable primarily to losses, property-related items, alternative minimum tax credit carryover of synthetic fuel 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, 2006 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 TECO Energy **Consolidated Financial Statements**).

In June 2006, the Financial Accounting Standards Board (FASB) issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. See further discussion of FIN 48 in **Note 2** to the TECO Energy **Consolidated Financial Statements** and the "Recently Issued Accounting Standards" section below.

Employee Postretirement Benefits

We sponsor a defined benefit pension plan (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 and with the help of external consultants. We consider market conditions, including changes in investment returns and interest rates, in making these assumptions.

Pension plan assets (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 pension plan's actual past experience, and current market conditions. The expected return on assets assumption was based on expectations of long-term inflation, real growth in the economy, fixed income spreads and equity premiums consistent with our portfolio, with provision for active management and expenses paid from the trust. The discount rate assumption is based on a cash flow matching technique developed by our outside actuaries and current economic conditions. This technique matches the yields from high-quality (AA-graded, non-callable) corporate bonds to the company's projected cash flows for the pension plan to develop a present value that is converted to a discount rate and this assumption is subject to change each year. The salary increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases. Holding all other assumptions constant, a 1% increase or decrease in the assumed rate of return on plan assets would decrease or increase, respectively, 2006 net periodic expense by approximately $4.4 million. Likewise, a 0.67% increase or a 0.42% decrease in the discount rate assumption would result in an approximately $3.4 million change in the 2006 net periodic pension expense. This $3.4 million change represents a 1-cent change in earnings-per-share.

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 FAS 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. The expected subsidy reduced the accumulated postretirement benefit obligations (ABPO) at Dec. 31, 2006 by $25.8 million and net periodic cost for 2006 by $3.8 million. In 2006, we filed and received a Part D subsidy of $0.6 million.

The assumed health care cost trend rate for medical costs was 9.5% in 2006 and decreases to 5.00% in 2016 and thereafter. A 1% increase in the health care trend rates would produce a 4% ($1.0 million) increase in the aggregate service and interest cost for 2006 and a 4% ($7.4 million) increase in the accumulated postretirement benefit obligation as of Sep. 30, 2006, the measurement date.

A 1% decrease in the health care trend rates would produce a 3% ($0.7 million) decrease in the aggregate service and interest cost for 2006 and a 3% ($6.0 million) decrease in the accumulated postretirement benefit obligation as of Sept. 30, 2006, the measurement date.

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.

See further discussion of Employee Postretirement Benefits in **Note 5** to the TECO Energy **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 environmental and legal contingencies and incurred but unreported 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. As a result, it is possible that the company could have to report a loss and respective liabilities in accounting periods before the offsetting proceeds from the insurance recovery and potential gain 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 the TECO Energy **Consolidated Financial Statements** for a complete discussion of certain legal contingencies that existed at Dec. 31, 2006.

Long-Lived Assets

In accordance with 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. We annually review all long-lived assets in the last quarter of each year to ensure that any gradual change over the year and the seasonality of the markets are considered when determining which assets require an 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.

At the end of the 2006 fiscal year impairment tests were conducted on our long-lived assets. At the conclusion of the analyses, it was determined that all asset carrying values were recoverable based on the reasonable estimates used. No impairment adjustments were necessary.

During 2005, we reduced our fair market value assumption for the McAdams power project, based on a strategic review of the options to dispose of that investment, which resulted in a further impairment charge related to additional asset retirement obligations (see **Note 15** to the TECO Energy **Consolidated Financial Statements**). All the remaining assets associated with the McAdams power project we sold in 2006 (see **Note 16** to the TECO Energy **Consolidated Financial Statements**).

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 TECO Energy **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 TECO Energy **Consolidated Financial Statements**).

Recently Issued Accounting Standards

Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans

In September 2006, the FASB issued FAS No.158, *Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)*. The company adopted FAS 158 on Dec. 31, 2006. This statement of financial accounting standards requires the recognition in the statement of financial position the over-funded or under-funded status of a defined benefit postretirement plan, measured as the difference between the fair value of plan assets and the benefit obligation in the case of a defined benefit plan, or the accumulated postretirement benefit obligation in the case of other postretirement benefit plans. As a result of this standard, the company reported as of Dec. 31, 2006, a $125.8 million increase in benefit liability on the balance sheet and a $21.8 million accumulated other comprehensive loss, net of estimated tax benefits. In addition, as a result of the application of FAS 71 to the impacts of FAS 158, Tampa Electric Company recorded $91.9 million in both benefit liabilities and regulatory assets. This standard does not affect the results of operations.

Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued FASB Interpretation (FIN) No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. Application involves a two-step approach where recognition occurs if the position exceeds a "more likely than not" threshold and the measurement is based on the tax benefit being greater than 50 percent likely of being realized upon settlement with the tax agencies involved. FIN 48 is effective for fiscal years beginning after Dec. 15, 2006. Based on the company's assessment to date of the tax positions as of Jan. 1, 2007, the company believes that the implementation of FIN 48 during the first quarter of 2007 will have an immaterial impact on retained earnings. In addition, as a result of reaching a favorable conclusion with a taxing authority during the first quarter of 2007, the company expects to record during the first quarter of 2007 a previously unrecognized gain in Discontinued Operations in the range between $12 and $15 million related to the disposition of the Union and Gila River power stations.

Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in the Current Year Financial Statements

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in the Current Year Financial Statements* (SAB 108). SAB 108 addresses the diversity in practice by registrants when quantifying the effect of an error on the financial statements and provides guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements. SAB No. 108 was adopted on Dec. 31, 2006 and did not have an impact on the company's consolidated financial statements.

Quantitative and Qualitative Disclosures about 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 Office is responsible for reducing and mitigating the market risk exposures which arise from the ownership of physical assets and contractual obligations, such as debt instruments and firm customer sales contracts. The primary objectives of the risk management organization, the Middle Office, are 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 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;
- Interest rate fluctuations on debt at TECO Energy and its affiliates;
- Price fluctuations for physical purchases of fuel at TECO Transport and TECO Coal;
- Price fluctuations for crude oil and the resulting reduction of synthetic fuel proceeds if crude oil prices exceed phase-out threshold levels.

The TECO Energy companies use 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 mitigate the price uncertainty related to commodity inputs, such as diesel fuel.

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 the **Unregulated Operating Companies** section and **Note 22** to the TECO Energy **Consolidated Financial Statements**).

Credit Risk

We have 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.

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. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

Credit exposures 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.

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, 2006 and 2005, a hypothetical 10% increase in the consolidated group's weighted average interest rate on its variable rate debt during the subsequent year, would not result 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 Company.

These amounts were determined based on the variable rate obligations existing on the indicated dates at TECO Energy and its subsidiaries. A hypothetical 10% decrease in interest rates would increase the fair market value of our long-term debt by approximately 3.2% and 2.8% at Dec. 31, 2006 and 2005, respectively (see the **Financing Activity** section and **Notes 6** and **7** to the **TECO Energy Consolidated Financial Statements**). The above sensitivities assume no changes to our financial structure and could be affected by changes in our credit ratings, changes in general economic conditions or other external factors (see the **Risk Factors** section).

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 risks.

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. However, 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 customers, 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, 2006 and 2005, a change in commodity prices would not have a material impact on earnings for Tampa Electric or PGS, but could have an impact on the timing of the cash recovery of the cost of fuel (see the **Tampa Electric** and **Regulation** sections).

Unregulated Operating Companies

Most of the unregulated subsidiaries at TECO Energy are subject to significant commodity risk. These include TECO Coal, TECO Transport and TECO Guatemala. 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, 2006 and 2005, 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 $7.1 million and $3.5 million, respectively. TECO Coal is also exposed to variability in operating costs as a result of periodic purchases of diesel oil in its operations. At Dec. 31, 2006, TECO Coal had utilized derivative instruments to reduce the price variability for approximately 50% of its anticipated 2007 diesel oil purchases. These derivative instruments qualify for cash flow hedge accounting treatment, and as such, variations in the value of the hedges would offset the price variation in diesel oil, reducing any impact to earnings.

TECO Coal is also indirectly exposed to changes in the price of crude oil. Under the rules governing synthetic fuel tax credits, those credits can be phased out in the event that the price of crude oil reaches a certain threshold. The synthetic fuel tax credit is determined annually and is estimated to be $1.21 per million Btu for 2006, and was $1.17 per million Btu in 2005 and $1.13 per million Btu in 2004. This rate escalates with inflation but could be limited by domestic oil prices. If the oil price limitation is reached, the level of the tax credits starts to decline. In 2006, average annual domestic oil prices, as measured by the DOE index, would have had to exceed $55 per barrel for this limitation to have been effective, and it was estimated that the tax credit would have been eliminated at an average oil price of $69 per barrel. The DOE index is based on the "Domestic First Purchase Price" not the NYMEX-quoted oil futures prices, which in 2006 averaged 90% of the NYMEX price per barrel. The synthetic fuel tax credit phase-out range for 2007 based on the DOE oil prices is expected to be $57 to $71 per barrel, which would be the equivalent of a NYMEX price of approximately $63 to $79 per barrel (see the **Synthetic Fuel** discussion in the **Outlook** section).

In January 2007, TECO Coal entered into oil price hedge instruments that protect against the risk of high oil prices reducing the value of the tax credits related to the production of synthetic fuel in 2007. When combined with the hedges entered into in October 2006, the additional instruments protect approximately $195 million of the gross cash benefits expected from the third-party investors for the production of synthetic fuel over the full expected average annual oil price range of $63 to $79 per barrel on a NYMEX basis. The oil price range between $63 and $79 per barrel is the expected phase-out range for synthetic fuel benefits for 2007. The hedges in place provide approximately a dollar-for-dollar recovery of lost synthetic fuel revenues in the event of a phase out over the estimated phase-out range. The total cost of the hedges was approximately $37 million (see the **Synthetic Fuel** discussion in the **Outlook** section).

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, 2006, nearly all of the potential fuel price variability for 2007 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, 2006.

Like Tampa Electric and PGS, TECO Guatemala has commodity price risk that is largely mitigated by the fact that increases in the price of fuel are passed through to the power purchasing distribution utility.

The following tables summarize the changes in and the fair value balances of energy derivative assets (liabilities) for the year ended Dec. 31, 2006:

Changes in Fair Value of Energy Derivatives (millions)

(millions)	
Net fair value of energy derivatives as of Dec. 31, 2005	$ 68.6
Net change in unrealized fair value of derivatives	(204.2)
Changes in valuation techniques and assumptions	—
Realized net settlement of derivatives	68.8
Net fair value of energy derivatives as of Dec. 31, 2006	$ (66.8)

Roll-Forward of Energy Derivative Net Assets (Liabilities) (millions)

(millions)	
Total energy derivative net assets (liabilities) as of Dec. 31, 2005	$ 68.6
Change in fair value of net derivative assets (liabilities):	
Recorded as regulatory assets and liabilities or OCI	(136.9)
Recorded in earnings	1.5
Net option premium payments	—
Net purchase (sale) of existing contracts	—
Net fair value of energy derivatives as of Dec. 31, 2006	$ 66.8)

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 at the date of valuation. Actual cash flows upon maturity could be materially different from the estimated value.

The following is a summary table of sources of fair value, by maturity period, for energy derivative contracts at Dec. 31, 2006.

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2006

(millions)	*Current*	*Non-current*	*Total Fair Value*
Source of fair value			
Actively quoted prices	$(70.2)	$(3.6)	$(73.8)
Model prices (1)	7.0	—	7.0
Total	$(63.2)	$(3.6)	$(66.8)

(1) 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

Other Income (Expense)

In 2006, Other income or (expense) of $153.6 million reflected the $46.6 million from the installment sale of the 98% interest in the synthetic fuel production facilities at TECO Coal, $58.6 million of pretax income from the Guatemalan operations, which are accounted for as equity investments, $34.8 million of pretax interest income on invested cash balances and $6.0 million of pretax gains on the smaller assets sold in 2006 partially offset by the debt reduction charges. Income from the sale of the interests in TECO Coal's synthetic fuel production facilities was reduced in 2006 by the 35% limitation on the tax credits due to high oil prices and lower production in 2006 (see the **TECO Coal** section). The debt reduction charges were $2.5 million in 2006, compared to $74.2 million in 2005.

In 2005, Other Income (expense) of $157.8 million reflected the installment sale of the 98% interest in the synthetic fuel production facilities at TECO Coal, income from the Guatemalan operations, which are on equity investment accounting, and gains on the smaller assets sold in 2005 partially offset by the debt extinguishment charges associated with our 2005 debt retirement program.

In 2004, Other Income (expense) of $23.1 million reflected the income related to the gain on the sale of the Hamakua Power Station, the sale of our interest in the propane business, the installment sale of the 90% interest in the synthetic fuel production facilities at TECO Coal, and income from the deconsolidated Guatemalan operations, largely offset by a $152.3 million pretax impairment charge related to our investment in the Texas Independent Energy (TIE) projects.

AFUDC equity at Tampa Electric, which is included in Other Income (expense), was $2.7 million in 2006 and $0.7 million in 2004, and there was no AFUDC recorded in 2005. AFUDC is expected to increase in 2007 due to the installation of NO_x control at Tampa Electric's Big Bend Station (see the **Environmental Compliance** and **Liquidity, Capital Resources** sections).

Interest Expense

Total interest expense was $278.3 million in 2006 compared to $288.7 million in 2005 and $322.9 million in 2004. In 2006, interest expense was reduced by the repayment in June 2005 of $380 million of 10.5% notes and the December 2005 repayment of $100 million of 8.5% trust preferred securities. Interest expense also reflects Tampa Electric's issuance of $250 million of 6.55% notes in May 2006 and use of proceeds to reduce short-term borrowings. In 2005, interest expense was reduced by the retirement of $391.6 million of trust preferred securities in late 2004, and the repayment in June 2005 of $380 million of 10.5% notes, partially offset by interest associated with $200 million of fixed-rate notes issued in May 2005 and $100 million of floating-rate notes issued in June 2005 (see the **Financing Activity** section), and higher short-term borrowings under credit facilities at Tampa Electric Company.

Interest expense is expected to decrease in 2007 due to the full-year benefits from the December 2006 retirement of the remaining 8.5% TruPS outstanding, the January 2007 retirement of $57 million of 5.93% junior subordinated notes and the planned retirement of the $300 million of 6.125% notes due in May 2007, partially offset by Tampa Electric Company's increased borrowings to support its capital spending program (see the **Liquidity, Capital Resources** section).

Income Taxes

The provision for income taxes increased in 2006 from higher operating income primarily due to lower debt extinguishment costs and lower interest expense. The provision for income taxes increased in 2005 as a result of more-normal operations and fewer write-offs of merchant generating assets. In 2004 the provision for income taxes was a benefit as we incurred net operating losses primarily as a result of losses on the disposition of merchant power generating assets. Income tax expense as a percentage of income from continuing operations before taxes was 32.7% in 2006, 32.6% in 2005 and 40.8% in 2004. For 2007, we expect the effective tax rate to be in the range of 30% to 35%.

The cash payments for income taxes, as required by the Alternative Minimum Tax Rules (AMT), state income taxes and payments related to prior years' audits was $10.4 million, $27.4 million and $22.4 million in 2006, 2005 and 2004, respectively.

Due to the generation of deferred income tax assets related to the net operating loss (NOL) carry-forward from disposition of the merchant generating assets, 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 NOLs through 2010. Beyond 2010, we expect to use more than $190 million of AMT carry-forward to limit future cash tax payments for federal income taxes to the level of AMT. Our current projection of cash income tax payments in 2007 is about $14 million, including amounts for refunds of foreign tax credits carried back to prior years and amounts owed to jurisdictions where we do not have NOLs. For the 2008-2010 period, we estimate tax payments to be in the range of $7 to $12 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. We recognized no tax credits in 2004 and $73.0 million in 2003. These tax credits are generated annually on qualified production at TECO Coal through Dec. 31, 2007, subject to changes in the law, regulation or administration that could impact the qualification for non-conventional fuel tax credits. We were unable to utilize any of these tax credits in both 2005 and 2004 due to our net tax loss position for the years. Under the Energy Policy Act of 2005 that was signed into law on Aug. 8, 2005, effective Jan. 1, 2006 tax credits from the production of synthetic fuels generated in 2006 and 2007 that could not be utilized in those years will be carried forward for 20 years.

The synthetic fuel tax credit is determined annually and is estimated to be $1.19 per million Btu for 2006 before phase-out, and was $1.17 per million Btu in 2005 and $1.13 per million Btu in 2004. This rate escalates with inflation but could be limited by domestic oil prices. (See the **Synthetic Fuel** discussion in the **Outlook** section and the discussion of the reference oil price in the **TECO Coal Outlook** section.)

In 2006, 2005 and 2004, income tax expense also reflected a decrease due to the impact of increased overseas operations with deferred U.S. tax structures. The decrease related to these deferrals was $9.2 million, $9.4 million and $10.5 million for 2006, 2005 and 2004, 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 - after-tax)	*2006*	*2005*	*2004*
Loss on operations	**$—**	$(11.6)	$ (96.0)
Gain on disposition of Union and Gila River	—	76.5	—
Frontera write-off	—	—	(25.6)
Frontera operations	—	—	(5.8)
Commonwealth Chesapeake operations	—	—	2.5
Commonwealth Chesapeake write-off	—	1.8	(51.3)
TECO Solutions/other	**1.9**	(3.2)	(20.3)
Total discontinued operations	**$ 1.9**	$ 63.5	$(196.5)

In 2006 net income from discontinued operations was $1.9 million, reflecting primarily the recovery of receivables and adjustments for estimates for businesses that had been previously written off. In 2005, net income from discontinued operations was $63.5 million, compared to a loss of $196.5 million in 2004. The 2005 results include the operating results from the Union and Gila River power stations through the end of May 2005 and the $76.5 million after-tax gain recorded upon the final disposition of the plants. Discontinued operations also include results for the Commonwealth Chesapeake Power Station until its sale in April 2005 and adjustments to estimates for impairments on previously divested assets.

Discontinued Operations/Asset Dispositions

TECO Energy completed a number of asset dispositions in 2006, 2005 and 2004 as part of a revised business strategy to focus on the electric and gas utilities and long-term profitable unregulated businesses and to reduce exposure to the merchant power sector. This process was completed with the sale of TECO Thermal in 2006 and the uncompleted McAdams Power

Station. In 2005, TWG Merchant sold its membership interest in Commonwealth Chesapeake Power Station (CCC) in Virginia and substantially all the assets of the Dell Power Station in Arkansas. BCH Mechanical, Inc. (BCH Mechanical) was also sold in 2005. In 2004, TWG Merchant completed both the sale of its 50% indirect interest in TIE and the sale of Frontera Generation Limited Partnership (Frontera), the owner of the Frontera Power Station in Texas. In 2004, TECO Guatemala sold its 50% indirect interest in the Hamakua Power Station (Hamakua) in Hawaii. TECO BGA, Inc. (TECO BGA), TECO AGC, Ltd. (TECO AGC), and substantially all the assets of Prior Energy were also sold in 2004. In addition, TECO Energy completed the sale of its general and limited partnership interests in Heritage Propane Partners, L.P. as part of a larger transaction that involved the merging of privately held Energy Transfer Company with Heritage Propane Partners in 2004. Results for CCC, BCH Mechanical, TECO Thermal, Frontera, Prior Energy, TECO BGA, and TECO AGC have been accounted for as discontinued operations for all periods reported. Revenues from these discontinued operations were $10.6 million and $141.7 million in 2005 and 2004, respectively (see **Notes 16** and **21** to the TECO Energy **Consolidated Financial Statements**). Included in continuing operations prior to their respective sales were the results from our interests in the Dell and McAdams power stations, TIE, Hamakua and Heritage Propane Partners.

TWG Merchant's interests in the Union and Gila River project companies, which owned merchant generation plants in Arkansas and Arizona, respectively, were held by an indirect wholly owned subsidiary of TWG Merchant, TECO-Panda Generating Company, L.P. (TPGC). TPGC was part of the TWG Merchant operating segment until designated as assets held for sale in December 2003. In 2005, TECO Energy completed the sale and transfer of the Union and Gila River project companies (see **Notes 16** and **21** to the TECO Energy **Consolidated Financial Statements**). TPGC's results are accounted for as discontinued operations for all periods reported. Revenues from the discontinued operations of TPGC in 2005 and 2004 were $109.1 million and $510.7 million, respectively. Net income (loss) from the discontinued operations of TPGC were $65.1 million and $(96.0) million in 2005 and 2004, respectively.

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-U), all items, all urban consumers as reported by the U.S. Department of Labor, was 2.5%, 3.4% and 3.3% in 2006, 2005 and 2004, 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 2007, with a 2.8% increase expected.

Prices for certain products and services used by TECO Energy's operating companies increased at rates above the CPI in 2006, including prices for concrete, steel and copper products and petroleum-based products used extensively in all of our operating companies, and for subcontracted services used by Tampa Electric and subcontracted mining services used by TECO Coal. These prices moderated in late 2006 and are expected to rise in 2007, but at a rate slower than in 2006. In the case of TECO Transport, a portion of the increased cost of petroleum products is passed through to its contract customers through fuel adjustment clauses while other costs are covered by inflation adjustment clauses, and Tampa Electric and PGS are eligible to 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

Environmental Matters

Our commitment to environmental compliance is an important element of our culture. Each of our operating companies has an environmental compliance plan tailored to its industry and location, each of which is part of our overall corporate compliance plan.

Among our companies, Tampa Electric has the most significant number of stationary sources with air emissions impacts and material Clean Water Act implications. Tampa Electric has taken significant steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (including IGCC and natural-gas fired combined cycle); a responsible fuel mix taking into account price and reliability impacts to its customers; a significant capital expenditure program to add Best Available Control Technology (BACT) emissions controls; additional controls to accomplish earlier reductions of certain emissions allowing for lower emission rates when BACT was ultimately installed; and enhanced controls and monitoring systems for certain pollutants. All of these improvements, including the installation of IGCC technology, BACT and repowering from coal to natural gas, represent an investment in excess of $2 billion since 1994.

Through these actions, Tampa Electric has achieved significant reductions of all air pollutants, including CO_2 while maintaining a reasonable fuel mix through the clean use of coal for the economic benefit of its customers. The early CO_2 reductions and pioneering use of IGCC technology positions us and Tampa Electric well for new laws and rules which may be enacted to address climate change related issues, including carbon reductions.

We believe that any government adopted carbon reduction program should: (1) apply across all sectors of the economy and address all sources of greenhouse gases (GHG); (2) recognize and give credit for early action and be based on a market driven "cap and trade" program with allocations based on the status of emissions and reductions to date, much like the program applicable to SO_2; and (3) include mechanisms for the development and deployment of new technologies, including the removal of regulatory and economic barriers or the inclusion of incentives for the use of those technologies for low emission generation, carbon capture, storage, wind, solar and other renewable energy resources, as well as cost effective development of demand-side management technologies and conservation incentives.

Air Quality Control

IGCC Technology – Polk Power Station

In 2006, Tampa Electric celebrated its tenth year of commercial operation of the Polk Power Station, originally a 260-megawatt Integrated Gasification Combined Cycle (IGCC) power plant, which was the first of its kind commercially available in operation. The IGCC unit was constructed in cooperation with the U.S. Department of Energy (DOE) as a part of its Clean Coal Program. DOE contributed approximately $140 million to assist in the commercialization of this technology to enable the clean burning of coal. This technology converts coal into a synthesis gas and removes 95% of the SO_2 from the gas prior to combustion and coupled with efficient combined-cycle technology uses approximately 10% less fuel for the same level of power output. The emission rates of this unit are very similar to a natural gas combined-cycle unit of the same size.

Polk Power Station has been recognized as the best example of IGCC technology in the United States and the cleanest coal-burning generating plant in North America. Tampa Electric is a leader in operations and maintenance experience and enhancement techniques for clean-coal burning technology. Operational improvements and the low cost of fuel make the Polk IGCC the most economical unit on Tampa Electric's system and it dispatches ahead of the Big Bend conventional coal-fired units.

The Energy Policy Act of 2005 encourages the development of clean-coal technologies. It authorized almost $1.1 billion over three years to fund the U. S. Department of Energy's (DOE) clean coal research and development programs. In 2006 the Internal Revenue Service and DOE awarded Tampa Electric $133 million of tax credits for its proposed 630 megawatt IGCC plant to be built at the Polk Power Station as contained in its 10-year site plan, which is expected to be in service after 2012 (see the **Tampa Electric** and **Liquidity, Capital Resources** and **Capital Expenditures** sections).

Consent Decree

Tampa Electric, through voluntary negotiations with the Environmental Protection Agency (EPA) and the U.S. Department of Justice and the Florida Department of Environmental Protection (FDEP), signed a Consent Decree, which became effective Feb. 29, 2000, and a Consent Final Judgment, which became effective Dec. 6, 1999, as settlement of federal and state litigation. 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 SO_2, projects for NO_x reduction efforts on Big Bend Units 1 through 4, and the repowering of the coal-fired Gannon Power Station to natural gas. The commercial operation dates for the two repowered units, renamed as the H. L. Culbreath Bayside Power Station (Bayside), were Apr. 24, 2003 and Jan. 15, 2004. The completed station has total station capacity of about 1,800 megawatts (nominal) of efficient, natural gas-fueled, combined-cycle electric generation, which uses 10% less fuel for the same amount of power output. The repowering has reduced the facility's NO_x and SO_2 emissions by approximately 99% and particulate matter emissions have decreased approximately 92% from 1998 levels.

In 2004, Tampa Electric made its NO_x reduction technology selection and decided to install SCRs for NO_x control on Big Bend Unit 4, with an expected in-service date by Jun. 1, 2007. Tampa Electric has also decided to install SCR technology 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. The engineering, design and construction of the SCR system are currently in progress. Tampa Electric's capital investment forecast includes amounts in the 2007 through 2011 period for compliance with the NO_x, SO_2 and particulate matter (PM) reduction requirements (see the **Capital Expenditures** 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 SCRs to be installed on all four of the units at the Big Bend Station and pre-SCR projects on Big Bend Units 1–3 (which are early plant improvements to reduce NO_x 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 Jun. 1, 2007 and cost recovery for the capital investment, which is dependent on filings related to the prudence of actual expenditures to be made in 2007, is expected to start in 2008.

Emission Reductions

Projects committed to under the Consent Decree and Consent Final Judgment have resulted in significant reductions in emissions. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM from its facilities by 160,000 tons, 41,000 tons, and 4,000 tons, respectively.

Reductions in SO_2 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 SO_2 emissions from the flue gas streams.

The repowering of Gannon Station to Bayside Station has resulted in a significant reduction in emissions of all pollutant types. We expect that Tampa Electric's actions to install additional NO_x emissions controls on all Big Bend units will result in the further reduction of emissions and that by 2010, the SCR projects will result in a total phased reduction of NO_x by 62,000 tons per year from 1998 levels.

In total, we expect that Tampa Electric's emission reduction initiatives will result in the reduction of SO_2, NO_x and PM emissions by 89%, 90%, and 72%, respectively, below 1998 levels by 2010. With these improvements in place, Tampa Electric's facilities meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in the community. As a result of all its already completed emission reduction actions, and upon completion of the SCR projects, we expect that Tampa Electric will have achieved emission reduction levels called for in Phase I of the Clean Air Interstate Rule (CAIR) when it is implemented in 2009.

Due to pollution control benefits from the environmental improvements, 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 NO_x controls at Big Bend Station, which would lead to a reduction of mercury emissions of more than 70% from 1998 levels by 2010. Tampa Electric expects to be in compliance with the Clean Air Mercury Rule (CAMR) Phase I requirements when they are implemented in 2010 without additional capital investment. The stricter standards required in 2018 by Phase II of CAMR may require additional control equipment.

The EPA has recently proposed modifications to the 24-hour coarse and fine particulate matter standards. Based on the reduced emissions of sulfates and nitrates resulting from projects associated with compliance with the Consent Decree, as well as local ambient air quality data, the Tampa Electric service area is expected to be in compliance with the proposed new PM standards without additional expenditures by Tampa Electric.

Carbon Reductions

We have historically supported voluntary efforts to reduce carbon emissions and has taken significant steps to reduce overall emissions at Tampa Electric's facilities. Since 1998, Tampa Electric has reduced its system-wide emissions of CO_2 by approximately 19%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 should remain near 1990 levels until the addition of the next baseload unit, which is expected after 2012. Tampa Electric estimates that the repowering to natural gas and the shut-down of coal-fired units resulted in a decrease in CO_2 emissions of approximately 4.0 million tons below 1998 levels. During this same timeframe, the numbers of retail customers and retail energy sales have risen by approximately 25%.

We believe new legislative and regulatory efforts to reduce CO_2 emissions will be more effective if any proposed legislation or rules recognize the early, voluntary steps some have taken to dramatically improve their emissions profiles (to provide an incentive to continue doing so before new legislation or regulations take effect), focus on technology development, and provide a regulatory structure that supports advanced clean coal IGCC technology or other similar technologies. As a result of Tampa Electric's already dramatic reductions in CO_2 emissions, it is well-positioned to engage in the carbon reduction debate. Many states, including California, and Congress have made proposals to reduce greenhouse gas emissions over an extended period. There are several means to address reductions in greenhouse gas emissions, including energy efficiency initiatives, more efficient automobiles, such as plug-in hybrids, and advanced clean coal technology such as Tampa Electric's IGCC facility Polk Power Station.

We stand by our commitment to achieve emissions reductions and technologies that provide a viable future for coal. We are a supporter of coal as a plentiful, cost-effective and reliable source of energy. We believe that the environmental controls in place at Tampa Electric's facilities and the successful operation of coal gasification for the production of electricity Tampa Electric have demonstrated that advanced clean coal is an environmentally sound, economic and reliable electric generation fuel source that will continue to have a viable future.

We believe that the important elements of CO_2 emissions reduction efforts include: (1) research and development efforts aimed at technology development for carbon capture and sequestration; (2) financial support for IGCC, such as the tax credits awarded to Tampa Electric in 2006; and (3) innovative regulatory mechanisms to address the higher capital costs of these clean technologies.

Tampa Electric belongs to the U.S. Department of Energy's Climate Challenge program and participates in the Chicago Climate Exchange, a voluntary but legally binding cap-and-trade program dedicated to reducing greenhouse gas emissions. Because of Tampa Electric's membership in the Chicago Climate Exchange, its CO_2 emissions are measured through the use of emissions monitoring equipment and audited annually by the National Association of Securities Dealers, which has certified the results thus far.

Florida has an Energy Commission charged with developing a comprehensive energy policy for the state. By statute the final report of the Commission is due on Dec. 31, 2007, a portion of which must include an action plan on climate change. Specifically, the legislation requires the Commission to "recommend consensus-based public-involvement processes that evaluate greenhouse gas emissions in this state and make recommendations regarding related economic, energy, and environmental benefits. The report must include recommended steps and a schedule for the development of a comprehensive state climate action plan with greenhouse gas reduction through a public-involvement process, including transportation and land use, generation; residential, commercial and industrial activities, waste management, agriculture and forestry; emissions-reporting systems; and public education." The Commission's organizational meeting was held in mid-February, 2007, subcommittees (including one on climate change) were formed, and meetings with opportunities for public input will be held throughout the remainder of the year.

Several states have proposed or enacted legislation to limit CO_2 emissions, and there is proposed legislation at the federal level that would limit CO_2 emissions. The timing of passage of any federal legislation is uncertain as is the period over which CO_2 emissions reductions would be required. Several bills have been introduced in Congress but none are on a fast track for action. Most of these bills contain some type of cap-and-trade system. Several of them focus on the power sector only but others are economy-wide and all of focus on some reductions from a baseline year; however, none of the details are defined.

In the case of Tampa Electric, we expect that the costs to comply with new environmental regulations would be eligible for recovery through the Environmental Cost Recovery Clause. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills.

In the case of TECO Coal, it is unclear if the requirements for CO_2 emissions reductions would impact it as a carbon-based fuel provider or the user. In either case, it could make the use of coal more expensive or less desirable, which could impact TECO Coal's margins and profitability.

Tampa Electric currently emits approximately 15 million tons of CO_2 per year. With a projected annual growth of electricity demand of 2.5%, Tampa Electric estimates an approximately 30% increase to approximately 20 million tons in 2020 due to the planned additional generation to meet customer growth. This level would be substantially the same as, or slightly below 1998 levels.

If legislation is adopted to require mandatory reductions in CO_2, the company favors recognition for early action and a cap-and-trade program in which allocations of allowances would be made based on performance against a baseline year supported by verifiable data. Currently the several proposals at the federal level have not yet received public input in a formal way so that the details of what might emerge are uncertain. Because there is no specific defined congressional proposal, we cannot reasonably predict the economic impact to the company of any adopted legislation. We will participate in the debate in an effort to include provisions for credit for early reductions, such as those already achieved by Tampa Electric, and for future percentage reductions that are reasonable.

In its ten-year site plan filed in 2006, Tampa Electric identified preliminary plans to build a 630-megawatt IGCC unit in 2013, in addition to two 180-megawatt natural gas-fired peaking units in 2007. The company would continue to run its existing coal- and natural gas-fired capacity.

Water Quality

Tampa Electric uses water from Tampa Bay at its Bayside and Big Bend facilities for cooling water. Both plants use mesh screens to reduce the adverse impacts to aquatic organisms. Big Bend units 3 and 4 use proprietary fine-mesh screens, the best available technology, to further reduce impacts to aquatic organisms. Water recycling and beneficial reuse programs are widely employed on the fresh water systems at both plants. Numerous methods are used to prevent storm water, and other water discharges protecting ground water and the waters of Tampa Bay.

Renewable Energy

Tampa Electric's renewable energy program uses energy from several sources to support customer demand for its Renewable Program. The majority of renewable energy comes from sources that include:

- Biomass, which is organic plant material from yard clippings and other vegetation. Tampa Electric has tested bahia grass as a fuel to generate electricity at the Polk Power Station. More than 60 tons of bahia grass, grown on the 4,300 acre plant site, were ground and mixed with the pulverized coal slurry used in the plant's gasifier.
- Photovoltaic panels have been installed at two schools, the Museum of Science and Industry and the Manatee Viewing Center to harness energy from the sun.
- Methane gas from a landfill is used to drive a microturbine at the Hillsborough Heights landfill.

Through the end of 2006, the environmental impacts of customers' participation in the program have been significant:

- More than 2 million kwhs of renewable energy have been produced to support participating customer requirements,

- Approximately 1,400 tons of coal have been offset with energy from renewable resources, and
- CO_2 reductions from using renewable resources are the equivalent of planting more than 5,800 acres of trees or removing almost 1,700 cars from the streets.

Conservation

Energy conservation is becoming increasingly important in a period of volatile energy prices and in the greenhouse gas emissions reduction debate. Tampa Electric offers customers a number of programs to conserve energy. These programs are designed to reduce peak energy demand which allows Tampa Electric to delay construction of future generation facilities. Since 1981, the conservation programs have reduced the summer peak demand by 251 megawatts, and the winter peak demand by 731 megawatts. These programs and their costs are approved annually by the FPSC with the costs recovered through a clause on the customer's bill. PGS also offers programs that enable customers to reduce their energy consumption with the costs recovered through customers' bills.

Superfund and Former Manufactured Gas Plant Sites

Tampa Electric Company, through its Tampa Electric and PGS divisions, is a potentially responsible party (PRP) for certain superfund sites and, through its PGS 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, 2006, Tampa Electric Company has estimated its ultimate financial liability to be approximately $12.3 million (primarily related to PGS), 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 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 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 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

The retail operations of Tampa Electric are regulated by the FPSC, which has jurisdiction over retail rates, quality of service and reliability, issuances of securities, planning, siting and construction of facilities, accounting and depreciation practices, and other matters.

In general, the FPSC's pricing objective is to set rates at a level that allows the utility to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The costs of owning, operating and maintaining the utility system, other than fuel, purchased power, conservation and certain environmental costs, are recovered through base rates. These costs include operation and maintenance expenses, depreciation and taxes, as well as a return on Tampa Electric's investment in assets used and useful in providing electric service (rate base). The rate of return on rate base, which is intended to approximate Tampa Electric's weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero cost rate and an allowed return on common equity. Base rates are determined in FPSC rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, the FPSC or other parties.

Tampa Electric is also subject to regulation by the Federal Energy Regulatory Commission (FERC) in various respects, including wholesale power sales, certain wholesale power purchases, transmission services, and accounting practices.

Federal, state and local environmental laws and regulations cover air quality, water quality, land use, power plant, substation and transmission line siting, noise and aesthetics, solid waste and other environmental matters (see **Environmental Compliance** section above).

Tampa Electric Rates

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 has not sought a base rate increase since 1992. Since that last rate proceeding it has earned within its allowed ROE range while adding almost 190,000 customers and making significant investments in facilities and infrastructure including baseload and peaking generating capacity additions to serve the growing customer base. Over time, current base rates may not support the additional transmission and distribution system reliability capital spending, storm hardening capital and operations and maintenance spending, other recurring capital expenditures and generally higher non-fuel operations and maintenance expenditures and still earn a return within its allowed ROE range.

Cost Recovery Clauses – Tampa Electric

Fuel, purchased power, conservation and certain environmental costs are recovered through levelized monthly charges established pursuant to the FPSC's cost recovery clauses. These charges, which are reset annually in an FPSC proceeding, are based on estimated costs of fuel, environmental compliance, conservation programs and purchased power and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs from the projected costs. The FPSC may disallow recovery of any costs that it considers imprudently incurred.

In September 2006, 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 2007. In November 2006, the FPSC approved Tampa Electric's requested rates. The rates include the cost for natural gas and coal expected in 2007, the collection of approximately $51 million of underestimated fuel and purchased power expenses in 2006, the collection of approximately $107 million for previously unrecovered 2005 fuel and purchased power expenses and the operating cost for and a return on the capital invested in the first SCR project to enter service on Big Bend Unit 4 as well as the operations and maintenance expense associated with the Big Bend Units 1–3 pre-SCR projects as required by the EPA Consent Decree and FDEP Consent Final Judgment (see the **Environmental Compliance** section). The rates were partially offset by actual and projected proceeds from the sale of approximately $105.8 million excess SO_2 emissions allowances in 2006 and 2007. Accordingly, Tampa Electric's residential customer rate per 1,000 kilowatt-hours increased $4.93 from $109.61 in 2006, when $100 million of proceeds from the sale of SO_2 emissions allowances were returned to customers, to $114.54 in 2007.

The FPSC determined that it was appropriate for Tampa Electric to recover SCR operating costs through the ECRC as well as earn a return on its SCR investment installed on Big Bend Unit 4 and Big Bend Units 1-3 in October 2004 and May 2005, respectively, for NO_x control in compliance with the environmental consent decree. The SCR for Big Bend Unit 4 is scheduled to enter service by Jun. 1, 2007. The SCRs for Big Bend Units 3, 2, and 1 are scheduled to enter service by May 1, 2008, 2009 and 2010, respectively. Cost recovery for the capital investment for each unit, which is dependent on filings made in the year each SCR enters service, is expected to start in 2008, 2009 and 2010, respectively.

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 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. Hearings regarding the prudence of the RFP process and final contract were held in the first half of 2004 and a final order on the matter was issued in October 2004, which 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.

Tampa Electric expects to issue a RFP for solid fuel transportation services on a schedule that will facilitate having a new contract for these services in place at the expiration of the current contract. The FPSC October 2004 order established the parameters for a bid process that would be acceptable to it. Tampa Electric plans to structure the RFP to comply with the FPSC order.

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. The final costs for restoration associated with hurricanes Charley, Frances and Jeanne in 2004 were approximately $74 million.

In June 2005, the FPSC approved a stipulation entered into by Tampa Electric, the Office of Public Counsel and the Florida Industrial Power Users Group regarding the treatment of Tampa Electric's 2004 hurricane costs. Under the stipulation, Tampa Electric agreed to reclassify approximately $39 million of the hurricane restoration costs as plant in service (rate base). With this adjustment and the normal $4 million annual storm accrual, Tampa Electric's storm reserve, which had a $30 million deficit balance, had a positive balance of about $14 million at the June start of the 2006 hurricane season and a $16 million balance at Dec. 31, 2006.

In the 2005 legislative session, the Florida Legislature passed a bill that would allow IOUs in Florida to "securitize" storm damage costs. Under this bill, IOUs would have the opportunity to recover hurricane restoration costs and establish a higher storm reserve fund through the sale of bonds that would be repaid by an FPSC-approved surcharge on customer bills. Tampa Electric elected to forego securitizing its 2004 hurricane costs following the approval of the stipulation discussed above. However, Tampa Electric continues to evaluate securitization and other options as possible means of funding for future storms.

Hardening of Transmission and Distribution Facilities

Due to extensive storm damage to utility facilities during the 2004 and 2005 hurricane seasons and the resulting outages utility customers experienced throughout the state, the FPSC initiated a proceeding to explore methods of designing and building transmission and distribution systems that would minimize long-term outages and restoration costs. Following a series of FPSC workshops to review 2004 and 2005 hurricane damage, restoration practices and activities, and plans for the 2006 hurricane season, the FPSC issued an order that required utilities to inspect wooden distribution poles every eight years and report the results of the inspections to the FPSC annually. For many years, Tampa Electric has routinely inspected its wooden poles and adjusted its inspection schedule to comply with the FPSC's order.

The FPSC subsequently issued an order requiring all investor owned utilities (IOUs) to implement a 10-point storm preparedness plan designed to improve the statewide electric infrastructure to better withstand severe storms and expedite recovery from future storms. In addition to a wood pole inspection program instituted separately, the plans address vegetation management, audits of pole attachments, transmission structure inspections and hardening, data gathering and analysis, natural disaster planning, coordination with local governmental agencies and collaborative research. In October 2006 the FPSC approved Tampa Electric's plan to comply with the directive. Tampa Electric is implementing its plan and estimates that the average incremental non-fuel operations and maintenance expense of this plan to be approximately $15 million annually.

The FPSC also modified its rule regarding the design standards for new and replacement transmission and distribution line construction, including certain critical circuits in a utility's system. Beyond employing accepted engineering practices and complying with the applicable edition of the National Electric Safety Code (NESC), the new design standard requires adoption of the NESC extreme wind loading standards for distribution facilities. The new design standards also encourage the placement of new or modified facilities underground when feasible. These new requirements are expected to increase the capital expenditures required to expand the system to meet growing customer demand and to maintain system reliability by approximately $20 million annually.

Florida's Energy Plan

The Florida Department of Environmental Protection has produced an energy plan for the state that, among other initiatives, encourages fuel diversity for electric generation, streamlining of the power plant siting review process, conservation by state agencies and consumers, educational programs for residential and business customers regarding energy conservation, expansion of the use of hydrogen and additional grants to study alternative energy supplies.

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 modified 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 RFPs for applicable capacity additions.

Market Based Rate Authority

As previously disclosed, in 2005 the FERC determined that Tampa Electric had market power within its own service territory and within the area served by Reedy Creek (Walt Disney World). At that time, Tampa Electric agreed to limit itself to only conducting wholesale cost-based transactions in those two parts of Florida.

In 2006, through the filing of additional market analysis, Tampa Electric was successful in convincing the FERC that it did not have market power in the Reedy Creek area. As a result, Tampa Electric is once again able to transact with Reedy Creek at market-determined prices, which is expected to provide benefits for both entities.

PGS Rates

PGS' current rates were agreed to in a settlement with all parties involved, and a final FPSC order was granted on Dec. 17, 2002 and rates were effective after Jan. 16, 2003. PGS' authorized 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.

PGS Cost Recovery Clauses

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the purchased gas adjustment clause. This charge is designed to recover the costs incurred by PGS for purchased gas, and for holding and using interstate pipeline capacity for the transportation of gas it sells to its customers. These charges may be adjusted monthly based on a cap approved annually in an FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a specific recovery period, with a true-up adjustment to reflect the variance of actual costs and usage from the projected charges for prior periods.

In November 2006, the FPSC approved rates under PGS' PGA for the period January 2007 through December 2007 for the recovery of the costs of natural gas purchased for its distribution customers.

In addition to its base rates and purchased gas adjustment clause charges for system supply customers, PGS customers (except interruptible customers) also pay a per-therm conservation charge for all gas. This charge is intended to permit PGS to recover its costs incurred in developing and implementing energy conservation programs, which are mandated by Florida law and approved and supervised by the FPSC. PGS is permitted to recover, on a dollar-for-dollar basis, expenditures made in connection with these programs if it demonstrates that the programs are cost effective for its ratepayers.

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. As a result, PGS receives its base rate for distribution regardless of whether a customer decides to opt for transportation-only service or continue bundled service. PGS had approximately 12,600 transportation customers as of Dec. 31, 2006 out of approximately 29,400 eligible customers.

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

CEO and CFO Certifications

The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to TECO Energy's Annual Report on Form 10-K for the year ended Dec. 31, 2006. The certification of TECO Energy's Chief Executive Officer regarding compliance with the New York Stock Exchange (NYSE) corporate governance listing standards required by NYSE will be filed with NYSE following the 2007 Annual Meeting of Shareholders. Last year, we filed this certification with the NYSE after the 2006 Annual Meeting of Shareholders, in compliance with NYSE rules.

Risk Factors

The following are certain factors that could affect our future results. They should be considered in connection with evaluating forward-looking statements, and are otherwise made by, or on behalf of, us, 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.

We have significant 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 and could prevent the payment of dividends if those payments would cause a violation of the covenants.

We and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements to use our and its respective credit facilities. Also, we, Tampa Electric Company 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** section and **Significant Financial Covenants** table in the **Liquidity, Capital Resources** sections of **MD&A** for descriptions of these tests and covenants.

As of Dec. 31, 2006, we were in compliance with required financial covenants, but we cannot assure you 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.

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 under **Off Balance Sheet Financing** and **Liquidity, Capital Resources** sections of the **MD&A**. In addition, our unconsolidated affiliates have incurred non-recourse debt. 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 ratings downgrades and we cannot be assured of any rating improvements in the future.

Our senior unsecured debt is rated below investment grade by Standard & Poor's (S&P) at BB with a stable outlook, by Moody's Investor's Services (Moody's) at Ba2 with a stable outlook and by Fitch Ratings (Fitch) at BB+ with a stable outlook. The senior unsecured debt of Tampa Electric Company is rated by S&P at BBB- with a stable outlook, by Moody's at Baa2 with a stable outlook and by Fitch at BBB+ with a stable outlook. Any downgrades by the rating agencies may affect our ability to borrow, may change requirements for future collateral or margin postings, and may increase our financing costs, which may decrease our earnings. We also may 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 current credit ratings or future downgrades. In addition, downgrades could adversely affect our relationships with customers and counterparties.

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 PGS could be required to post collateral to support their purchases of gas and electricity.

Our financial condition and results could be adversely affected if our capital expenditures are greater than forecast.

We are forecasting higher levels of capital expenditures, primarily at Tampa Electric, for compliance with our environmental consent decree, to support normal customer growth, to comply with the FPSC's mandated design changes to harden transmission and distribution facilities against hurricane damage, and to improve coal-fired generating unit reliability. We are also in the early stages of exploring the technology options for the next large generating capacity needs at Tampa Electric. There are large differences in the capital needs depending on the final technology chosen. Pending a technology decision, the costs for the next large generating capacity addition are not factored into our current capital spending forecast shown in the **Capital Expenditures** section of **MD&A**.

Our capital expenditures may exceed the planned amount. If we are unable to maintain capital expenditures at the forecasted levels, we may need to draw on credit facilities or access the capital markets on unfavorable terms. We cannot be sure that we will be able to obtain additional financing, in which case our financial position, earnings and credit ratings could be adversely affected.

If we are not able to complete the sale of TECO Transport we are considering, our plans to accelerate the retirement of parent level debt and support Tampa Electric's increased capital spending needs may be adversely affected.

If we are unable to complete a sale of TECO Transport, we would not be positioned to accelerate our goal of retiring our parent level debt earlier than our current forecast. In addition, if a sale were not completed, we would have to consider other options to support Tampa Electric's capital spending plans, which could include the sale of other businesses or capital markets transactions.

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 are 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, 2006, 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 spending and shortfalls in operating cash flow. These are in addition to any restrictions on dividends from our subsidiaries to us discussed above.

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

A portion of our debt bears interest at variable rates, including the floating rate notes we issued in June 2005. Increases in interest rates, therefore, may require a greater portion of our cash flow to be used to pay interest. In addition, changes in interest rates and capital markets generally affect our cost of borrowing and access to these markets.

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 Tampa Electric's service area and in Florida is important to the realization of Tampa Electric's and PGS' respective forecasts for annual energy sales growth. An unanticipated downturn or a failure of market conditions to improve, such as the current slowdown in the housing markets, in the Tampa Electric service areas or in Florida's economy could adversely affect Tampa Electric's or PGS' expected performance.

Our unregulated businesses, TECO Transport, TECO Coal and TECO Guatemala, 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 electric 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. Although 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 electric and gas 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' financial performance by, for example, increasing competition or costs, threatening investment recovery or impacting rate structure.

Tampa Electric's earnings may decrease and it may not be able to earn its allowed return with the current base rates.

Tampa Electric's profitability may decrease and it may not be able to earn within its allowed ROE range under its current base rates due to higher recurring capital spending primarily in the transmission and distribution areas and generally higher levels of non-fuel operations and maintenance spending, even without the construction of new generating capacity.

In order to earn within its allowed ROE range given its higher operations and maintenance costs and the increased investment in infrastructure and facilities, Tampa Electric may have to file for higher rates with the FPSC. While the FPSC has a history of constructive regulation, we cannot predict the outcome of any such regulatory proceeding.

Our businesses are sensitive to variations in weather and the effects of extreme 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, could adversely affect operating costs and sales and cause damage to our facilities, requiring 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 natural gas. Tampa Electric is able to recover prudently incurred costs 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 natural gas and pipeline capacity are recovered through retail customers' bills, but increases in natural gas costs affect total retail prices, and therefore, the competitive position of PGS relative to electricity, other forms of energy and other gas suppliers.

In the case of TECO Coal, the selling price of coal may cause it to either decrease or increase production. If production is decreased, there may be costs associated with idling facilities or write-offs of reserves that are no longer economic.

Changes in customer energy usage patterns may affect sales at our utility companies.

The average energy usage per Tampa Electric residential customer declined in 2006. We believe that this was in response to mild weather, higher energy prices reflected both through the fuel charge on electric bills and for higher energy prices in general, and to changes in residential construction patterns in Tampa Electric's service area.

Tampa Electric's forecasts are based on normal weather patterns and long-term historical trends in customer energy use patterns. Tampa Electric's ability to increase energy sales and earnings could be negatively impacted if energy prices increase in general and customers continue to use less energy in response to higher energy prices.

In 2006, the number of multi-family residences completed in Tampa Electric's service area was the highest level since 2001. New multi-family residential construction tends to be smaller and more energy efficient than traditional detached residences therefore the per-residential customer usage is lower for these residences. The number of multi-family building permits issued in Tampa Electric's service area in 2006 compared to detached residences indicates that this trend may continue in 2007. A higher percentage of multi-family residences may cause a further decline in per-residential customer usage.

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 electricity and natural gas may be hindered.

We depend on transmission and distribution facilities owned and operated by other utilities and energy companies to deliver the electricity and natural gas we sell to the wholesale and retail markets, 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.

We may be unable to take advantage of our existing tax credits and deferred tax benefits.

We have generated significant tax credits and deferred tax assets that are being carried over to future periods to reduce future cash payments for income tax. Our ability to utilize the carry-over credits and deferred tax assets is dependent upon sufficient generation of future taxable income.

Changes in the relationship between the Producer First Purchase Price and the NYMEX oil prices could affect the value of our hedges.

We have entered into oil price hedge transactions to protect the earnings and cash benefits for the vast majority of our expected 2007 synthetic fuel production. We have hedged approximately $195 million of the expected proceeds from investors related to the production of synthetic fuel in 2007 on the assumption that the Producer First Purchase Price would average 90% of the NYMEX per barrel oil price. Changes in this relationship could change the range over which the oil price hedge instruments that we have in place protect our synthetic fuel production benefits.

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

We test our 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, we 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, our subsidiaries 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.

There is increasing debate and discussion regarding the regulation of greenhouse gas emissions and some states have already proposed or enacted regulations relating to these emissions, which if enacted could increase our costs or the costs of our customers or curtail sales.

Among our companies, Tampa Electric has the most significant number of stationary sources with air emissions. The form of any greenhouse gas emission regulation, either federal or state, is unknown at this time and potential costs to reduce greenhouse gases are unknown. Presently there is no viable technology to remove CO_2 post-combustion from conventional coal-fired units such as Tampa Electric's Big Bend units.

Regulation in Florida allows utility companies to recover from customers prudently incurred costs for compliance with new environmental regulations. Tampa Electric would expect to recover from customers the costs of power plant modifications or other costs required to comply with new greenhouse gas emission regulation, but increased costs for electricity may cause customers to change usage patterns, which would impact Tampa Electric's sales. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the Environmental Cost Recovery Clause, Tampa Electric could seek to recover those costs through a base-rate proceeding, but we can not predict whether the FPSC would grant such recovery.

In the case of TECO Coal, the use of coal to generate electricity is considered a significant source of greenhouse gas emissions. New regulations, depending on final form, could cause the consumption of coal to decrease or the cost of sales to increase, which could negatively impact TECO Coal's earnings.

TECO Transport does a significant amount of business under certain U.S. government programs that are dependent on annual appropriations.

TECO Transport participates in the U.S. Cargo Preference Program and the in PL480 program for shipments of U.S. aid grain, which are funded annually through the U.S. government's appropriation process. While these programs have been funded at stable levels for many years, Congress could reduce funding in the future. Our outlook, however, assumes that these programs continue to be funded at levels similar to the last several years.

A repeal of the Jones Act could result in increased competition and reduced profitability for TECO Transport.

TECO Transport is a U.S. flag carrier with a major portion of its business subject to the Jones Act The Jones Act restricts oceangoing shipments directly between U.S. ports and all inland waterway business to U.S. vessels built in U.S. shipyards, owned by citizens of the U.S., and with U.S. citizen crews and it has, on occasion, been cited as a cause for higher costs by certain domestic industries which have lobbied for repeal of the act or waivers for shipments carried by non-U.S. flag vessels under certain circumstances. A repeal or modification of the Jones Act opening this trade to non-U.S. flag vessels could potentially increase competition and reduce profitability.

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

Our projects in Guatemala 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. TECO Guatemala attempts 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.

Guatemala, similar to many countries, has been experiencing increasing fuel and corresponding electricity prices. As a result, TECO Guatemala's operations are exposed to increased risks as the country's government and regulatory authorities seek ways to reduce the cost of energy to its consumers.

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, but these measures may not be successful.

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.

TECO Energy and certain of its subsidiaries have been named as defendants in lawsuits, as more fully described under **Legal Contingencies**, in **Note 12** to the **TECO Energy Consolidated Financial Statements**. We intend to vigorously defend all of these proceedings, however, 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.

This page left intentionally blank.

Consolidated Balance Sheets

Assets *(millions, except for share amounts)*	*Dec. 31, 2006*	*Dec. 31, 2005*
Current assets		
Cash and cash equivalents	**$ 441.6**	$ 345.7
Restricted cash	**37.3**	37.6
Receivables, less allowance for uncollectibles of $4.6 and $6.9 at Dec. 31, 2006 and Dec. 31, 2005, respectively	**338.3**	323.3
Inventories, at average cost		
Fuel	**85.0**	84.9
Materials and supplies	**74.6**	68.9
Current regulatory assets	**255.7**	273.3
Current derivative assets	**7.1**	64.0
Prepayments and other current assets	**46.1**	51.5
Total current assets	**1,285.7**	1,249.2
Property, plant and equipment		
Utility plant in service		
Electric	**5,030.4**	4,892.3
Gas	**877.7**	839.5
Construction work in progress	**334.1**	200.0
Other property	**841.9**	822.7
Property, plant and equipment	**7,084.1**	6,754.5
Accumulated depreciation	**(2,317.2)**	(2,187.6)
Total property, plant and equipment (net)	**4,766.9**	4,566.9
Other assets		
Deferred income taxes	**630.2**	759.9
Other investments	**8.0**	8.0
Long-term regulatory assets	**231.3**	99.9
Long-term derivative assets	**0.1**	4.9
Investment in unconsolidated affiliates	**292.9**	297.1
Goodwill	**59.4**	59.4
Deferred charges and other assets	**87.3**	116.8
Assets held for sale	—	8.0
Total other assets	**1,309.2**	1,354.0
Total assets	**$7,361.8**	$7,170.1

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

Consolidated Balance Sheets (continued)

Liabilities and Capital *(millions, except for share amounts)*	***Dec. 31, 2006***	*Dec. 31, 2005*
Current liabilities		
Long-term debt due within one year		
Recourse	**$ 566.7**	$ 5.9
Non-recourse	**1.3**	1.3
Jr. subordinated notes	**71.4**	—
Notes payable	**48.0**	215.0
Accounts payable	**326.5**	354.7
Customer deposits	**129.5**	115.2
Current regulatory liabilities	**46.7**	146.8
Current derivative liabilities	**70.3**	0.3
Interest accrued	**50.5**	50.0
Taxes accrued	**25.3**	34.9
Liabilities associated with assets held for sale	—	1.8
Other current liabilities	**14.2**	—
Total current liabilities	**1,350.4**	925.9
Other liabilities		
Investment tax credits	**14.7**	17.3
Long-term regulatory liabilities	**555.3**	543.1
Long-term derivative liabilities	**3.7**	—
Deferred credits and other liabilities	**496.1**	382.9
Long-term debt, less amount due within one year		
Recourse	**3,202.2**	3,519.8
Non-recourse	**10.4**	11.7
Junior subordinated notes	—	177.7
Total other liabilities	**4,282.4**	4,652.5
Commitments and contingencies (see **Note 11**)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 209.5 million shares and 208.2 million shares outstanding at Dec. 31, 2006 and Dec. 31, 2005, respectively)	**209.5**	208.2
Additional paid in capital	**1,466.3**	1,527.0
Retained earnings (deficit)	**83.7**	(83.1)
Accumulated other comprehensive loss	**(30.5)**	(51.1)
Common equity	**1,729.0**	1,601.0
Unearned compensation	—	(9.3)
Total capital	**1,729.0**	1,591.7
Total liabilities and capital	**$7,361.8**	$7,170.1

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,*		*2006*	*2005*	*2004*
Revenues				
Regulated electric and gas (includes franchise fees and gross receipts taxes of $104.2 in 2006, $87.2 in 2005 and $83.8 in 2004)		**$2,660.3**	$ 2,293.8	$2,101.0
Unregulated		**787.8**	716.3	538.4
Total revenues		**3,448.1**	3,010.1	2,639.4
Expenses				
Regulated operations				
Fuel		**803.4**	461.1	536.7
Purchased power		**221.3**	269.7	172.3
Cost of natural gas sold		**365.3**	350.2	226.2
Other		**294.0**	270.3	258.2
Operation other expense				
Mining related costs		**450.2**	412.5	333.9
Waterborne transportation costs		**217.8**	191.8	182.0
Other		**15.6**	49.3	74.6
Maintenance		**183.3**	168.4	137.4
Depreciation and amortization		**282.2**	282.2	275.9
Other		**—**	—	6.0
Taxes, other than income		**217.5**	194.7	184.3
Sale of previously impaired assets / asset impairments		**(20.7)**	3.2	632.2
Total expenses		**3,029.9**	2,653.4	3,019.7
Income (loss) from operations		**418.2**	356.7	(380.3)
Other income (expense)				
Allowance for other funds used during construction		**2.7**	—	0.7
Gain on the sale of assets and other income		**94.5**	171.6	143.0
Loss on debt extinguishment		**(2.5)**	(74.2)	(4.4)
Impairment of TIE investment		**—**	—	(152.3)
Income from equity investments		**58.9**	60.4	36.1
Total other income (expense)		**153.6**	157.8	23.1
Interest charges				
Interest expense		**279.4**	288.7	323.2
Allowance for borrowed funds used during construction		**(1.1)**	—	(0.3)
Total interest charges		**278.3**	288.7	322.9
Income (loss) before provision for income taxes		**293.5**	225.8	(680.1)
Provision (benefit) for income taxes		**118.7**	101.9	(245.1)
Income (loss) from continuing operations before minority interest		**174.8**	123.9	(435.0)
Minority interest		**69.6**	87.1	79.5
Income (loss) from continuing operations		**244.4**	211.0	(355.5)
Discontinued operations				
Income (loss) from discontinued operations		**2.3**	88.2	(294.0)
Income tax provision (benefit)		**0.4**	24.7	(97.5)
Total discontinued operations		**1.9**	63.5	(196.5)
Net income (loss)		**$ 246.3**	$ 274.5	$ (552.0)
Average common shares outstanding	– Basic	**207.9**	206.3	192.6
	– Diluted	**208.7**	208.2	192.6
Earnings per share from continuing operations	– Basic	**$ 1.18**	$ 1.02	$ (1.85)
	– Diluted	**$ 1.17**	$ 1.00	$ (1.85)
Earnings per share from discontinued operations	– Basic	**$ 0.01**	$ 0.31	$ (1.02)
	– Diluted	**$ 0.01**	$ 0.31	$ (1.02)
Earnings per share – Basic		**$ 1.19**	$ 1.33	$ (2.87)
– Diluted		**$ 1.18**	$ 1.31	$ (2.87)
Dividends paid per common share outstanding		**$ 0.76**	$ 0.76	$ 0.76

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

Consolidated Statements of Comprehensive Income

(millions) *For the years ended Dec. 31,*	***2006***	*2005*	*2004*
Net income (loss)	**$246.3**	$274.5	$(552.0)
Other comprehensive income (loss), net of tax			
Net unrealized (losses) gains on cash flow hedges	**(0.3)**	(0.1)	4.8
Minimum pension liability adjustments	**42.7**	(7.2)	7.2
Other comprehensive income (loss), net of tax	**42.4**	(7.3)	12.0
Comprehensive income (loss)	**$288.7**	$267.2	$(540.0)

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

Consolidated Statements of Cash Flows

(millions) *For the years ended Dec. 31,*	***2006***	*2005*	*2004*
Cash flows from operating activities			
Net income (loss)	**$246.3**	$274.5	$(552.0)
Adjustments to reconcile net income (loss) to net cash from operating activities:			
Depreciation and amortization	**282.2**	282.2	289.6
Deferred income taxes	**112.5**	110.8	(355.3)
Investment tax credits, net	**(2.6)**	(2.7)	(2.9)
Allowance for other funds used during construction	**(2.7)**	—	(1.0)
Amortization of unearned compensation	**11.5**	5.5	13.6
Gain on sales of business/assets, pretax	**(67.0)**	(261.6)	(92.9)
Equity in earnings of unconsolidated affiliates, net of cash distributions on earnings	**(3.4)**	(35.9)	(34.3)
Minority interest expense	**(69.6)**	(87.1)	(79.5)
Debt extinguishment	**2.5**	19.8	—
Asset impairment	—	3.2	876.7
Goodwill and intangible asset impairment	—	—	16.6
TMDP arbitration (recovery) reserve	—	—	(5.6)
Deferred recovery clause	**53.4**	(154.3)	25.1
Receivables, less allowance for uncollectibles	**(26.0)**	(56.7)	32.1
Inventories	**(5.8)**	(38.1)	41.8
Prepayments and other deposits	**11.4**	(11.3)	3.6
Taxes accrued	**(17.0)**	(17.4)	(82.0)
Interest accrued	**0.5**	17.5	76.7
Accounts payable	**(18.0)**	119.0	(69.2)
Other	**58.7**	9.7	38.5
Cash flows from operating activities	**566.9**	177.1	139.6
Cash flows from investing activities			
Capital expenditures	**(455.7)**	(295.3)	(273.2)
Allowance for funds used during construction	**2.7**	—	1.0
Net proceeds from sales of business/assets	**100.4**	278.3	349.5
Net cash reduction from deconsolidation	—	—	(22.7)
Restricted cash	**0.3**	47.6	(34.3)
Distributions from unconsolidated affiliates	**7.3**	2.8	45.4
Other non-current investments	**(6.7)**	0.9	24.7
Cash flows (used in) from investing activities	**(351.7)**	34.3	90.4
Cash flows from financing activities			
Dividends	**(158.7)**	(157.7)	(145.2)
Proceeds from sale of common stock	**12.5**	16.2	10.2
Proceeds from long-term debt	**327.5**	311.9	—
Repayment of long-term debt	**(199.3)**	(494.1)	(225.0)
Contributions from minority interest owners	**65.7**	83.1	76.1
Exchange of equity units	—	180.2	(17.7)
Net increase (decrease) in short-term debt	**(167.0)**	100.0	77.5
Equity contract adjustment payments	—	(2.0)	(17.4)
Cash flows (used in) from financing activities	**(119.3)**	37.6	(241.5)
Net increase (decrease) in cash and cash equivalents	**95.9**	249.0	(11.5)
Cash and cash equivalents at beginning of the year	**345.7**	96.7	108.2
Cash and cash equivalents at end of the year	**$441.6**	$345.7	$ 96.7
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest (net of amounts capitalized) [1]	**$259.4**	$288.9	$372.1
Income taxes	**$ 10.4**	$ 27.4	$ 22.4

(1) Included in interest paid during the year is interest paid on debt obligation for discontinued operations of $12.0 million and $51.5 million for 2005 and 2004, respectively. No interest was paid in 2006 for debt related to discontinued operations.

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, 2003	187.8	$187.8	$1,220.8	$339.5	$(55.8)	$(14.6)	$1,677.7
Net loss				(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
Net income				274.5			274.5
Other comprehensive loss, after tax					(7.3)		(7.3)
Common stock issued	1.6	1.6	19.6			(5.0)	16.2
Cash dividends declared			(157.7)				(157.7)
Final settlement of equity security units	6.9	6.9	173.3				180.2
Amortization of unearned compensation						5.5	5.5
Tax benefits — stock options			2.4				2.4
Performance shares						(6.0)	(6.0)
Balance, Dec. 31, 2005	208.2	$208.2	$1,527.0	$ (83.1)	$(51.1)	$ (9.3)	$1,591.7
Net income				246.3			246.3
Other comprehensive income, after tax					42.4		42.4
Common stock issued	1.3	1.3	9.4				10.7
Cash dividends declared			(79.2)	(79.5)			(158.7)
Stock compensation expense			11.5				11.5
Adoption FAS 123(R)			(9.3)			9.3	—
Tax benefits — stock options			1.4				1.4
Adoption of FAS 158					(21.8)		(21.8)
Performance shares			5.5				5.5
Balance, Dec. 31, 2006	209.5	$209.5	$1,466.3	$ 83.7	$(30.5)	$—	$1,729.0

(1) TECO Energy had a maximum of 400 million shares of $1 par value common stock authorized as of Dec. 31, 2006, 2005 and 2004.

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

Notes to 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 FASB 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 certain 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 19**).

Use of Estimates

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 the first quarter of 2005, the company revised internal reporting information used for decision making purposes by viewing the results and performance of TECO Guatemala, Inc. (TECO Guatemala) (formerly TWG Non-Merchant, Inc.) as a separate segment comprised of all Guatemalan operations. TECO Guatemala includes the equity investments in the San José and Alborada Power Stations, the equity investment in the Guatemalan distribution company, Empresa Eléctrica de Guatemala, S.A. (EEGSA), and the TECO Guatemala parent company. Results for TECO Guatemala were previously reported in the Other Unregulated segment. Following the sales of the larger energy services businesses, which were previously reported in the Other Unregulated segment, the remaining small operations of TECO Solutions, Inc. (TECO Solutions) are now reported within Other & Eliminations. Prior period segment results have been restated to reflect the revised segment structure (see **Note 14**).

In 2006, only historical data is presented for TWG Merchant as all merchant assets have been divested. Any residual results for 2006 are included in "Other and eliminations".

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, 2006 and 2005 includes $30.0 million and $30.3 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 $30.0 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, 2006 and 2005 also includes $7.1 million and $7.3 million, respectively, of cash held in escrow related to the 2003 sale of Hardee Power Partners (HPP). The $7.1 million will be released from escrow in 2012, upon maturity of debt financing currently held by the purchaser of HPP. Restricted cash also included other unrelated amounts totaling approximately $0.2 million at Dec. 31, 2006.

Cost Capitalization

Debt issuance costs – The company capitalizes the external costs of obtaining debt financing and amortizes such costs over the life of the related debt. These costs are included in "Deferred Charges and Other Assets" on TECO Energy's Consolidated Balance Sheet.

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 $0.1 million and $0.7 million of interest costs in 2005 and 2004, respectively. No interest costs were capitalized in 2006.

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 and Peoples Gas System (PGS) 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 EEGSA. A major maintenance revenue recovery component is explicit 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 computes 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. Total depreciation expense for the years ended Dec. 31, 2006, 2005, and 2004 was $270.3 million, $267.6 million and $257.6 million, respectively. Total plant acquisition adjustments were $10.0 million as of Dec. 31, 2005. There were no acquisition adjustments in 2006. 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 2006, 4.0% for 2005 and 3.9% for 2004.

The implementation of FAS No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) in 2003 and FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations, an Interpretation of FASB Statement No. 143* (FIN 47) in 2005 resulted in increases in the carrying amount of long-lived assets and the liabilities associated with those assets. In addition, the accumulated reserve for cost of removal was reclassified to "Regulatory liabilities". 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 2006 and 2004. No projects qualified for AFUDC in 2005 while total AFUDC for 2006 and 2004 was $3.8 million and $1.0 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 interests for each investment at Dec. 31, 2006 and 2005 are presented in the following table:

TECO Energy's Percent Ownership in Unconsolidated Affiliates [5]

Dec. 31,	**2006**	2005
TECO Transport		
Ocean Dry Bulk, LLC	**50%**	50%
TECO Guatemala		
Empresa Eléctrica de Guatemala, S.A. (EEGSA)	**24%**	24%
Central Generadora Electrica San José, Limitada (San José or CGESJ)[1]	**100%**	100%
Tampa Centro Americana de Electricidad, Limitada (Alborada or TCAE)[1]	**96%**	96%
Other		
Litestream Technologies, LLC[2]	**36%**	36%
Walden Woods Business Center, Ltd.	**50%**	50%
TECO Funding Company I, LLC[3][4]	**100%**	100%
TECO Funding Company II, LLC[3][4]	**100%**	100%

(1) TECO Energy can no longer consolidate CGESJ or TCAE (the project companies for the San José and Alborada power plants, respectively, in Guatemala), as a result of the application FIN 46R, Consolidation of Variable Interest Entities as it relates to long-term power purchase agreements with affiliated entities. See **Notes 14** and **19** for additional details.

(2) In 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, 2006 and 2005.

(3) As of Jan. 1, 2004, in accordance with the interpretation and application of the consolidation guidance established in FIN 46R, TECO Energy did not consolidate Capital Funding I or II. See **Notes 7** and **19** for additional details.

(4) On Dec. 20, 2005, all outstanding subordinated notes held by TECO Funding Company I, LLC were redeemed and the LLC was subsequently dissolved. On Jan. 16, 2007, all outstanding subordinated notes held by TECO Funding Company II, LLC matured.

(5) TECO Energy, Inc. received $55.5 million, $24.5 million and $1.8 million during the years ended Dec. 31, 2006, 2005 and 2004, respectively, as dividends from unconsolidated affiliates.

Regulatory Assets and Liabilities

Tampa Electric and PGS are subject to the provisions of Financial Accounting Standard (FAS) No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71) (see **Note 3** for additional details).

Deferred Income Taxes

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.

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 (SEC's) Staff Accounting Bulletin (SAB) 104, *Revenue Recognition in Financial Statements*. The interpretive criteria outlined in SEC's 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 FAS 71 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 for energy marketing operations at 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, 2006, 2005 and 2004 were $0.8 million, $3.8 million and $3.9 million, respectively.

Other Income and Minority Interest

TECO Energy earns a significant portion of its income indirectly through the synthetic fuel operations at TECO Coal. At the end of 2006, 2005 and 2004, TECO Coal had sold ownership interests in the synthetic fuel facilities to unrelated third-party investors equal to 98%, 98% and 90%, respectively. These investors pay for the purchase of the ownership interests as synthetic fuel is produced. The payments are based on the amount of production and sales of synthetic fuel and the related, underlying value of the tax credit, which is subject to potential limitation based on the price of domestic crude oil. These payments are recorded in "Other income" in the Consolidated Statements of Income.

Additionally, the outside investors make payments towards the cost of producing synthetic fuel. These payments are reflected as a benefit under "Minority interest" in TECO Energy's Consolidated Statements of Income and these benefits comprise the majority of that line item.

For the year ended Dec. 31, 2006, "Other income" reflected a phase-out of approximately 35% of the benefit of the underlying value of any 2006 tax credits based on an estimate of the average annual price of domestic crude oil during 2006. Should the Dec. 31, 2006 estimate of the average annual price of domestic crude oil be different than this estimate, the cash payments and the benefits recognized in "Other income" and "Minority interest" will be adjusted, either positively or negatively, in the first quarter of 2007. No phase-out of the benefit was recognized in 2005. (See the "Critical Accounting Policies and Estimates" section of Item 7, MD&A for a sensitivity evaluation regarding this estimate.)

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, 2006 and 2005, unbilled revenues of $47.8 million and $52.3 million, respectively, are included in the "Receivables" line item on TECO Energy's Consolidated Balance Sheets.

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 Hardee Power Partners, Ltd. (HPP) in October 2003, 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 power purchase agreement, which has been approved by the FERC and the 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 durations 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 $221.3 million, $269.7 million and $172.3 million, for the years ended Dec. 31, 2006, 2005 and 2004, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered 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 $104.2 million, $87.2 million and $83.8 million for the years ended Dec. 31, 2006, 2005 and 2004, 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, 2006, 2005 and 2004, these totaled $104.0 million, $87.0 million and $83.6 million, respectively.

Asset Impairments

TECO Energy and its subsidiaries apply the provisions of Statement of Financial Accounting Standards (FAS) No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* 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. See **Note 18** for specific details regarding the results of these assessments.

Deferred Charges and Other Assets

Deferred charges and other assets consist primarily of mining development costs amortized on a per ton basis and offering costs associated with various debt offerings that are being amortized over the related obligation period as an increase in interest expense.

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. The company and its subsidiaries' have a self-insurance program supplemented by excess insurance coverage for the cost of claims whose ultimate value exceeds the company's retention amounts. The company estimates its liabilities for auto, general, marine protection & indemnity, and workers' compensation using discount rates mandated by statute or otherwise deemed appropriate for the circumstances. Discount rates used in estimating these liabilities at Dec. 31, 2006 and 2005 ranged from 4.00% to 4.75%.

Stock-based Compensation

Effective Jan. 1, 2006, TECO Energy accounts for its stock-based compensation in accordance with FAS No. 123 (revised 2004), *Share-Based Payment* (FAS 123R). Under the provisions of FAS 123R, share-based compensation cost is measured at the grant date, based on the calculated fair value of the award, and is recognized as an expense over the employee's or director's requisite service period (generally the vesting period of the equity grant). Prior to this, the company accounted for its share-based payments under Accounting Principles Board (APB) Opinion No. 25, *Accounting for Stock Issued to Employees* and its related interpretations and the disclosure requirements of FAS 123, Accounting for Stock-Based Compensation, as amended by FAS 148, *Accounting for Stock-Based Compensation – Transition and Disclosure.* The company elected to adopt the modified-prospective transition method as provided under FAS 123R and, accordingly, results for prior periods have not been restated. See Note 9, Common Stock, for more information on share-based payments.

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 credit facility contains a covenant that could limit the payment of dividends exceeding a calculated amount (initially $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 Company.

In addition, TECO Diversified, Inc., a wholly-owned subsidiary of TECO Energy and the holding company for TECO Transport and TECO Coal, 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 additional information on significant financial covenants.

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 2006, 2005 and 2004 were not material. 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 20**.

2. *New Accounting Pronouncements*

Asset Retirement Obligations

FIN 47 was issued in March 2005 and became effective as of Dec. 31, 2005. FIN 47 clarifies the term "conditional asset retirement obligation" as a legal obligation to perform an asset retirement activity in which the timing and method of settlement are conditional on a future event that may or may not be within the control of the entity, and clarifies when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation. The company implemented FIN 47 during the fourth quarter of 2005. See **Note 15** for discussion of the effects of this implementation.

Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans

In September 2006, the FASB issued FAS No.158, Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R). This statement of financial accounting standards requires the recognition in the statement of financial position of the over-funded or under-funded status of a defined benefit postretirement plan, measured as the difference between the fair value of plan assets and the projected benefit obligation in the case of a defined benefit plan, or the accumulated postretirement benefit obligation in the case of other postretirement benefit plans. Compared to the current recognition of pension and other postretirement obligations on the balance sheet, this standard requires the recognition of: 1) the impact of future salary increases to the pension obligation and 2) the unamortized post-retirement benefit costs that are currently being expensed over the service lives of the participants. This standard also requires recognition in other comprehensive income certain benefit cost components that are not part of net periodic benefit cost, and that the defined benefit plan assets and obligations be measured as of the balance sheet date. For the regulated segments, amounts required to be recorded in "Other comprehensive income" are reflected as a regulatory asset, as pension obligations will be recovered through rates. FAS 158 is effective for publicly-held companies for fiscal years ending after Dec. 15, 2006. The company has adopted the balance sheet recognition provisions of FAS 158 at Dec. 31, 2006 and will adopt the year-end measurement date in 2008. This standard has increased benefit liabilities on the balance sheet by approximately $125.8 million and accumulated other comprehensive loss, net of estimated tax benefits, by approximately $21.8 million. This standard does not affect the company's results of operations or cash flows.

Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in the Current Year Financial Statements

In September 2006, the Securities and Exchange Commission staff issued Staff Accounting Bulletin No. 108, *Considering the Effects of Prior Year Misstatements When Quantifying Misstatements in the Current Year Financial Statements* (SAB 108). SAB 108 addresses the diversity in practice by registrants when quantifying the effect of an error on the financial statements and provides guidance on the consideration of the effects of prior year misstatements in quantifying current year misstatements. The company has adopted the provisions of SAB No. 108 effective Dec. 31, 2006. The adoption of SAB 108 did not have an impact on the company's consolidated financial statements.

Fair Value Measurements

In September 2006, the FASB issued FAS No. 157, *Fair Value Measurements* (FAS 157). FAS 157 defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles, and expands disclosures about fair value measurements. FAS 157 emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and states that a fair value measurement should be determined based on the assumptions that market participants would use in pricing the asset or liability. FAS 157 applies under other accounting pronouncements that require or permit fair value measurements. The effective date is for fiscal years beginning after Nov. 15, 2007. The company is currently assessing the implementation of FAS 157, however, does not believe it will be material to its results of operations, statement of position or cash flows.

Planned Major Maintenance

In September 2006, the FASB issued FASB Staff Position (FSP) *AUG AIR-1 Accounting for Planned Major Maintenance Activities*. This FSP effectively removes the accrual-in-advance method of accounting for future planned major maintenance activities. The FASB believes that the accrual-in-advance method results in the recognition of liabilities prior to the occurrence of a transaction or event that obligates the entity and that does not meet the definition of a liability in accordance with FASB Concept No. 6, *Elements of Financial Statements*. Entities are still permitted to use the built-in overhaul, deferral or direct expensing methods. This FSP is effective for the first fiscal year beginning after Dec. 15, 2006 and the company has adopted this FSP effective Jan. 1, 2007. Because the company has been applying the direct expensing method, the company does not believe adoption of this FSP will have an effect on its results of operations, statement of position or cash flows.

Determining the Variability of Variable Interest Entities

In April 2006, the FASB issued FSP FIN 46(R)-6, *Determining the Variability to Be Considered in Applying FASB Interpretation No. 46(R)*. In this FSP, the FASB addresses how a reporting enterprise should determine the variability to be considered in applying FASB Interpretation No. 46 (revised December 2003), *Consolidation of Variable Interest Entities*. The FASB describes a number of risks that should be considered as well as the purpose for which the entities were created, in order to determine the variability of these entities. The company has reviewed this FSP and has incorporated it into its process for determining the variability for current and future entities. This FSP is not expected to materially impact the company's results of operations, statement of position or cash flows.

Amendment to Derivatives Accounting

In February 2006, the FASB issued FAS No. 155, Accounting for Certain Hybrid Financial Instruments (FAS 155), which amends FAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and FAS No. 140, Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities. FAS 155 simplifies the accounting for certain derivatives embedded in other financial instruments by permitting fair value re-measurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation. This statement is effective for all financial instruments acquired or issued after the beginning of an entity's first fiscal year that begins after Sep. 15, 2006. The company adopted FAS 155 effective Jan. 1, 2007, and it does not materially impact the company's results of operations, statement of position or cash flows.

Accounting for Uncertainty in Income Taxes

In June 2006, the FASB issued FIN No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109* (FIN 48). FIN 48 prescribes a recognition threshold and measurement attribute for financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return, and also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. Application involves a two-step approach where recognition occurs if the position exceeds a "more likely than not" threshold and the measurement is based on the tax benefit being greater than 50 percent likely of being realized upon settlement with the tax agencies involved. FIN 48 is effective for fiscal years beginning after Dec. 15, 2006. Based on the company's assessment to date of the tax positions as of Jan. 1, 2007, the company believes that the implementation of FIN 48 during the first quarter of 2007 will have an immaterial impact on retained earnings.

3. Regulatory

As discussed in **Note 1**, Tampa Electric's and PGS's retail businesses are regulated by the FPSC. Tampa Electric is subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Public Utility Holding Company Act of 2005 ("PUHCA 2005"), which replaced the Public Utility Holding Company Act of 1935 which was repealed, however, pursuant to a waiver granted in accordance with FERC's regulations, TECO Energy is not subject to certain of the accounting, record-keeping, and reporting requirements prescribed by FERC's regulations under PUHCA 2005.

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% and are in effect until such time as changes are occasioned by an agreement approved by the FPSC or other FPSC actions resulting from rate or other proceedings initiated by Tampa Electric, FPSC staff or other interested parties.

Tampa Electric has not sought a base rate increase to recover significant plant investment since 1992, including the Bayside Power Station, which entered service in 2003 and 2004.

Cost Recovery – Tampa Electric

In September 2006, Tampa Electric filed with the FPSC for approval of fuel and purchased power, capacity, environmental and conservation cost recovery rates for the period January 2007 through December 2007. In November 2006, the FPSC approved Tampa Electric's requested changes. The rates include the costs of natural gas and coal prices expected in 2007, the collection of underestimated fuel and purchased power expenses in 2006, the collection of previously unrecovered 2005 fuel and purchased power expenses, the proceeds from the sale of sulfur dioxide (SO_2) emissions allowances and the operating costs for and a return on the capital invested in the first SCR project to enter service on Big Bend Unit 4 as well as the O&M costs associated with the pre-SCR projects for Big Bend Units 1 - 3 as required by the Environmental Protection Agency (EPA) Consent Decree and Florida Department of Environmental Protection (FDEP) Consent Final Judgment (see **Note 12** for additional details regarding projected environmental expenditures). In addition, the rates 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. 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 September 2006, PGS filed its annual request with the FPSC to change its Purchased Gas Adjustment (PGA) cap factor for 2007. The PGA rate can vary monthly due to changes in actual fuel costs but is not expected to exceed the FPSC approved annual cap. In November 2006, the FPSC approved the cap factor under PGS' PGA for the period January 2007 through December 2007.

SO_2 Emission Allowances

The Clean Air Act Amendments of 1990 established SO_2 allowances to manage the achievement of SO_2 emissions requirements. The legislation also established a market-based SO_2 allowance trading component.

An allowance authorizes a utility to emit one ton of SO_2 during a given year. The EPA allocates allowances to utilities based on mandated emissions reductions. At the end of each year, a utility must hold an amount of allowances at least equal to its annual emissions. Allowances are fully marketable and, once allocated, may be bought, sold, traded or banked for use currently or in future years. In addition, the EPA withholds a small percentage of the annual SO_2 allowances it allocates to utilities for auction sales. Any resulting auction proceeds are then forwarded to the respective utilities. Allowances may not be used for compliance prior to the calendar year for which they are allocated. Tampa Electric accounts for these using an inventory model with a zero basis for those allowances allocated to the company. Tampa Electric recognizes a gain at the time of sale, approximately 95% of which accrues to retail customers through the environmental cost recovery clause.

Over the years, Tampa Electric has acquired allowances through EPA allocations. Also, over time, Tampa Electric has sold unneeded allowances based on compliance and allowances available. The SO_2 allowances unneeded and sold in 2006 resulted from lower emissions at Tampa Electric brought about by environmental actions taken by the company under the Clean Air Act.

For the year ended Dec. 31, 2006, Tampa Electric sold approximately 44,500 allowances, resulting in proceeds of $45.0 million, the majority of which is included as a cost recovery clause regulatory liability. In the years ended Dec. 31, 2005 and 2004, approximately 100,000 and 13,000 allowances were sold for $79.7 million and $7.4 million in proceeds, respectively.

Other Items

Storm Damage Cost Recovery

Following Hurricane Andrew in 1992, Florida's investor owned utilities (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.

The costs for restoration associated with hurricanes Charley, Frances and Jeanne in 2004 were approximately $75 million, which exceeded the storm damage reserve by $30 million. These excess costs over the reserve amounts were charged against the reserve and were reflected as a regulatory asset. The storm costs did not reduce earnings but did reduce cash flow from operations.

In June 2005, the FPSC approved a stipulation entered into by Tampa Electric, the OPC and the Florida Industrial Power Users group regarding the treatment of Tampa Electric's 2004 hurricane costs. Under the stipulation, Tampa Electric agreed to reclassify approximately $39 million of the hurricane restoration costs as plant in service (rate base). With this adjustment and the normal $4 million annual storm accrual, Tampa Electric's storm reserve is $16 million as of Dec. 31, 2006.

Coal Transportation Contract

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. The decision allows, but does not require, Tampa Electric to rebid the water transportation and terminal service 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. On Mar. 1, 2005, the FPSC heard oral arguments on the motion and denied Tampa Electric's request for reconsideration and clarification. The impact of the FPSC vote was fully recognized by Tampa Electric in 2004.

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. 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, 2006 and 2005 are presented in the following table:

Regulatory Assets and Liabilities

(millions) Dec. 31,	**2006**	2005
Regulatory assets:		
Regulatory tax asset[1]	**$ 49.5**	$ 55.3
Other:		
Cost recovery clauses	**239.2**	264.1
Post-retirement benefit asset [4]	**148.9**	—
Deferred bond refinancing costs[2]	**26.7**	28.8
Environmental remediation	**12.3**	14.2
Competitive rate adjustment	**5.5**	5.6
Other	**4.9**	5.2
	437.5	317.9
Total regulatory assets	**487.0**	373.2
Less current portion	**255.7**	273.3
Long-term regulatory assets	**$231.3**	$ 99.9
Regulatory liabilities:		
Regulatory tax liability[1]	**$ 20.6**	$ 23.4
Other:		
Deferred allowance auction credits	**0.8**	1.3
Recovery clause related	**28.9**	136.9
Environmental remediation	**12.3**	14.2
Transmission and distribution storm reserve	**16.3**	12.5
Deferred gain on property sales[3]	**6.8**	7.7
Accumulated reserve – cost of removal	**516.1**	493.8
Other	**0.2**	0.1
	581.4	666.5
Total regulatory liabilities	**602.0**	689.9
Less current portion	**46.7**	146.8
Long-term regulatory liabilities	**$555.3**	$543.1

(1) Related to plant life and derivative positions.

(2) Amortized over the term of the related debt instrument.

(3) Amortized over a 5-year period with various ending dates.

(4) Related to the adoption of FAS 158. See **Note 5**.

All regulatory assets are being recovered through the regulatory process. The following table further details our regulatory assets and the related recovery periods:

Regulatory assets

(millions) Dec. 31,	***2006***	*2005*
Clause recoverable [1]	**$244.7**	$269.7
Earning a rate of return [2]	**152.6**	3.0
Regulatory tax assets [3]	**49.5**	55.3
Capital structure and other [3]	**40.2**	45.2
Total	**$487.0**	$373.2

(1) To be recovered through cost recovery clauses approved by the FPSC on a dollar for dollar basis in the next year.

(2) Primarily reflects allowed working capital, which is included in rate base and earns an 8.2 % rate of return as permitted by the FPSC.

(3) "Regulatory tax assets" and "Capital structure and other" regulatory assets have a recoverable period longer than a fiscal year and are recognized over the period authorized by the regulatory agency. Also included are unamortized loan costs which are amortized over the life of the related debt instruments. See footnotes 1 and 2 in the prior table for additional information.

4. *Income Tax Expense*

Income tax expense consists of the following components:

Income Tax Expense (Benefit)

(millions)	*Federal*	*Foreign*	*State*	*Total*
2006				
Continuing operations				
Current payable	$ 1.0	$2.8	$ 5.4	$ 9.2
Deferred	87.2	0.2	24.7	112.1
Amortization of investment tax credits	(2.6)	—	—	(2.6)
Income tax expense from continuing operations	85.6	3.0	30.1	118.7
Discontinued operations				
Deferred	8.5	—	(8.1)	0.4
Income tax expense (benefit) from discontinued operations	8.5	—	(8.1)	0.4
Total income tax expense	$ 94.1	$3.0	$22.0	$119.1
2005				
Continuing operations				
Current payable	$ 2.0	$7.5	$ 9.0	$ 18.5
Deferred	63.7	0.8	21.6	86.1
Amortization of investment tax credits	(2.7)	—	—	(2.7)
Income tax expense from continuing operations	63.0	8.3	30.6	101.9
Discontinued operations				
Deferred	35.3	—	(10.6)	24.7
Income tax expense (benefit) from discontinued operations	35.3	—	(10.6)	24.7
Total income tax expense	$ 98.3	$8.3	$ 20.0	$ 126.6
2004				
Continuing operations				
Current payable	$ (7.6)	$(1.1)	$ 10.6	$ 1.9
Deferred	(193.2)	0.3	(51.2)	(244.1)
Amortization of investment tax credits	(2.9)	—	—	(2.9)
Income tax benefit from continuing operations	(203.7)	(0.8)	(40.6)	(245.1)
Discontinued operations				
Current payable	8.3	—	5.6	13.9
Deferred	(110.6)	—	(0.8)	(111.4)
Income tax (benefit) expense from discontinued operations	(102.3)	—	4.8	(97.5)
Total income tax benefit	$(306.0)	$(0.8)	$(35.8)	$(342.6)

As discussed in **Note 1**, TECO Energy uses the liability method to determine deferred income taxes. 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, 2006 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,	**2006**	2005
Deferred income tax assets[1]		
Property related	**$115.8**	$254.2
Alternative minimum tax credit carryforward	**197.6**	192.4
Investment in partnership	**55.3**	65.1
Net operating loss carryforward	**763.4**	757.4
Other	**147.9**	167.3
Total deferred income tax assets	**1,280.0**	1,436.4
Deferred income tax liabilities[1]		
Property related	**(584.3)**	(572.9)
Deferred fuel	**(65.5)**	(103.6)
Total deferred income tax liabilities	**(649.8)**	(676.5)
Net deferred tax assets	**$ 630.2**	$759.9

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

Included in the "Property related" component of the deferred tax asset is the impact of the asset impairments discussed in **Notes 18** and **20**.

At Dec. 31, 2006, the company has cumulative unused federal and state (Florida) net operating losses of approximately $1,999.0 million and $1,158.6 million, respectively, expiring in 2025 and 2026 respectively. In addition, the company has available alternative minimum tax credit carryforwards for tax purposes of approximately $198 million which may be used indefinitely to reduce federal income taxes.

Effective Income Tax Rate

(millions) For the years ended Dec. 31,	***2006***	*2005*	*2004*
Net income (loss) from continuing operations before minority interest	**$174.8**	$123.9	$(435.0)
Plus: minority interest	**69.6**	87.1	79.5
Net income (loss) from continuing operations	**244.4**	211.0	(355.5)
Total income tax provision (benefit)	**118.7**	101.9	(245.1)
Income (loss) from continuing operations before income taxes	**363.1**	312.9	(600.6)
Income taxes on above at federal statutory rate of 35%	**127.1**	109.5	(210.2)
Increase (decrease) due to			
State income tax, net of federal income tax	**18.7**	18.1	(26.3)
Foreign income taxes	**2.2**	6.6	(0.8)
Amortization of investment tax credits	**(2.6)**	(2.7)	(2.9)
Permanent reinvestment – foreign income	**(9.2)**	(9.4)	(10.5)
Non-conventional fuels tax credit	**(2.1)**	—	—
AFUDC equity	**(1.0)**	—	(0.3)
Dividend income	—	1.6	14.6
State rate change	**2.7**	2.4	—
State valuation allowance	**2.1**	—	—
Depletion	**(9.8)**	(8.4)	(2.0)
Other	**(9.4)**	(15.8)	(6.7)
Total income tax provision (benefit) from continuing operations	**$118.7**	$101.9	$(245.1)
Provision for income taxes as a percent of income from continuing operations, before income taxes	**32.7%**	32.6%	40.8%

For the three years presented, we experienced a number of events that have impacted the overall effective tax rate on continuing operations. These events included permanent reinvestment of foreign income under APB Opinion No. 23, *Accounting for Taxes – Special Areas* (APB 23), adjustment of deferred tax assets for the effect of an enacted change in state rates, depletion, repatriation of foreign source income to the United States, and reduction of income tax expense under the new "tonnage tax" regime.

At Dec. 31, 2006, the portion of cumulative undistributed earnings from our investments in EEGSA was approximately $72.1 million. With the exception of the earnings repatriated in 2005, these earnings have been and are intended to be indefinitely invested in foreign operations. Therefore, no provision has been made for U.S. taxes or foreign withholding taxes that may be applicable upon actual or deemed repatriation.

On Oct. 22, 2004, the President of the United States signed the American Jobs Creation Act of 2004 (the Act). The Act creates a temporary incentive for U.S. corporations to repatriate accumulated income earned abroad by providing an 85% dividend received deduction for certain dividends from controlled foreign corporations. The company elected to apply Code Section 965 with respect to its 2005 dividends. For the twelve months ended Dec. 31, 2005, the company repatriated $38.9 million, resulting in $1.0 million of additional tax expense net of foreign tax credits. The tax savings related to the repatriation provision of the Act are reflected in the "Other" category in the effective income tax rate.

Code Section 248 of the Act also introduced a new "tonnage tax" which allows corporations to elect to exclude from gross income certain income from activities connected with the operation of a U.S. flag vessel in U.S. foreign trade and become subject to a tax imposed on the per-ton weight of the qualified vessel instead. The company elected to apply Code Section 248 for qualified vessels in 2006 and 2005.

The consolidated entity recorded a net state benefit in 2006, 2005 and 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 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 required for the alternative minimum tax, state income taxes, and prior year audit in 2006, 2005 and 2004 was $10.4 million, $27.4 million and $22.4 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.

Amounts disclosed for pension benefits also include the unfunded obligations for the supplemental executive retirement plan. This is a non-qualified, non-contributory defined benefit retirement plan available to certain members of senior management.

TECO Energy reported other comprehensive income of $42.7 million in 2006 for adjustments to the minimum pension liability. The adjustments to other comprehensive income related to the minimum pension liability in 2006 are net of $35.1 million of after-tax charges that, for regulatory purposes prescribed by FAS 71, were recorded as regulatory assets for Tampa Electric and PGS. TECO Energy had recorded other comprehensive losses of $7.2 million in 2005 and other comprehensive income of $7.2 million in 2004 related to adjustments to the minimum pension liability associated with the pension plans; there were no impacts of FAS 71 in 2005 or 2004 related to the additional minimum pension liability adjustments (see **Note 10**).

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 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 an age and service schedule. In 2007, the company expects to make a contribution of about $12.8 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 added 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. The company has determined that prescription drug benefits available to certain Medicare-eligible participants under its defined-dollar-benefit postretirement health care plan are at least "actuarially equivalent" to the standard drug benefits that are offered under Medicare Part D.

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). The guidance in FSP 106-2 requires (a) 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 (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits. TECO Energy adopted FSP 106-2 retroactive for the second quarter of 2004.

In 2006, the company received its first subsidy payment under Part D and has filed and is awaiting approval for its 2007 Part D subsidy application with the Centers for Medicare and Medicaid Services (CMS).

Obligations and Funded Status	*Pension Benefits*		*Other Benefits*	
(millions)	***2006***	*2005*	***2006***	*2005*
Change in benefit obligation				
Net benefit obligation at prior measurement date[1]	**$562.1**	$545.4	**$ 206.2**	$ 185.7
Service cost	**15.8**	16.2	**5.9**	6.4
Interest cost	**30.7**	32.6	**11.3**	11.3
Plan participants' contributions	**—**	—	**3.3**	2.7
Actuarial (gain) loss	**(4.5)**	7.1	**(9.9)**	14.2
Settlement	**—**	(3.1)	**—**	—
Gross benefits paid	**(34.2)**	(36.1)	**(13.4)**	(14.1)
Federal subsidy on benefits paid	**n/a**	n/a	**(0.6)**	n/a
Net benefit obligation at measurement date[1]	**$569.9**	$562.1	**$ 202.8**	$ 206.2
Change in plan assets				
Fair value of plan assets at prior measurement date[1]	**$434.7**	$407.6	**$ —**	$ —
Actual return on plan assets	**27.0**	44.4	**—**	—
Employer contributions	**7.7**	21.9	**10.1**	11.4
Plan participants' contributions	**—**	—	**3.3**	2.7
Settlement	**—**	(3.1)	**—**	—
Gross benefits paid	**(34.2)**	(36.1)	**(13.4)**	(14.1)
Fair value of plan assets at measurement date[1]	**$435.2**	$434.7	**$ —**	$ —
Funded status				
Fair value of plan assets	**$435.2**	$434.7	**$ —**	$ —
Benefit obligation	**569.9**	562.1	**202.8**	206.2
Funded status at measurement date[1]	**(134.7)**	(127.4)	**(202.8)**	(206.2)
Net contributions after measurement date	**30.8**	0.3	**2.1**	2.6
Unrecognized net actuarial loss	**138.8**	143.3	**15.6**	26.6
Unrecognized prior service (benefit) cost	**(4.5)**	(4.9)	**29.7**	32.7
Unrecognized net transition (asset) obligation	**—**	—	**16.5**	19.2
Accrued liability at end of year	**$ 30.4**	$ 11.3	**$(138.9)**	$(125.1)
Amounts Recognized in Balance Sheet				
Long-term regulatory assets	**$ 99.1**	n/a	**$ 49.8**	n/a
Prepaid benefit cost	**—**	28.6	**—**	n/a
Intangible assets	**—**	1.9	**—**	n/a
Accrued benefit costs and other current liabilities	**(1.3)**	n/a	**(12.8)**	n/a
Deferred credits and other liabilities	**(103.3)**	(17.3)	**(190.0)**	(125.1)
Additional minimum liability	**—**	(85.9)	**—**	n/a
Accumulated other comprehensive (loss) income (pretax)	**35.9**	84.0	**14.1**	n/a
Net amount recognized at end of year	**$ 30.4**	$ 11.3	**$(138.9)**	$(125.1)

(1) The measurement date was Sept. 30, 2006 and 2005.

Amounts recognized in accumulated other comprehensive income consist of:

	Pension Benefits		*Other Benefits*	
	2006	*2005*	***2006***	*2005*
Net actuarial loss (gain)	**$35.4**	n/a	**$ (5.5)**	n/a
Prior service cost (credit)	**0.5**	n/a	**15.9**	n/a
Transition obligation (asset)	—	n/a	**3.7**	n/a
	$35.9		**$14.1**	

The accumulated benefit obligation for all defined benefit pension plans was $508.3 million and $509.7 million at Sep. 30, 2006 and 2005, respectively.

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

Accumulated benefit in excess of plan assets		
(millions)	***2006***	*2005*
Projected benefit obligation, measurement date	**$569.9**	$562.1
Accumulated benefit obligation, measurement date	**508.3**	509.7
Fair Value of plan assets, measurement date	**435.2**	434.7

Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income

Net periodic benefit cost:	*Pension Benefits*			*Other Benefits*		
(millions)	***2006***	*2005*	*2004*	***2006***	*2005*	*2004*
Service cost	**$15.8**	$16.2	$17.0	**$ 6.0**	$ 6.5	$ 4.3
Interest cost	**30.7**	32.7	33.0	**11.3**	11.2	10.8
Expected return on plan assets	**(35.7)**	(37.2)	(39.1)	—	—	—
Amortization of:						
Actuarial loss	**8.8**	4.3	2.7	**0.5**		0.7
Prior service (benefit) cost	**(0.5)**	(0.5)	(0.6)	**3.0**	3.0	1.8
Transition (asset) obligation	—	(0.2)	(1.1)	**2.7**	2.7	2.7
Curtailment loss	—	—	0.5			
Settlement loss	—	1.4	6.6			
Net periodic benefit cost	**$19.1**	$16.7	$19.0	**$23.5**	$23.4	$20.3

Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income

(millions)	*Balance at Dec. 31, 2004*	*Movement for the year ended Dec. 31, 2005*	*Balance at Dec. 31, 2005*	*the year ended Dec. 31, 2006*	*Movement for adjustment to implement FAS 158*	*Balance at Dec. 31, 2006*[(1)]
Additional minimum pension liability	$(44.3)	$(7.2)	$(51.5)	$42.7	$ 8.8	$ —
Unrecognized pension losses and prior service costs	—	—	—	—	(22.0)	(22.0)
Unrecognized other benefit losses, prior service costs and transition obligations	—	—	—	—	(8.6)	(8.6)
Total accumulated other comprehensive income, net of taxes	$(44.3)	$(7.2)	$(51.5)	$42.7	$(21.8)	$(30.6)

(1) These balances exclude the pretax amounts recognized as Regulated Assets by Tampa Electric and Peoples Gas System as detailed as follows on a pretax basis:

Related to Additional Minimum Pension Liability	
Unrecognized pension losses and prior service costs	$ 57.0
Related to the adoption of FAS 158	
Unrecognized pension losses and prior service costs	$ 42.1
Unrecognized other benefit losses, prior service costs and transition obligations	49.8
Total related to the adoption of FAS 158, pretax	91.9
Total postretirement benefits included in regulated assets, pretax	$148.9

The estimated net loss and prior service net cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are $2.3 million and $0.1 million, respectively. The estimated prior service cost and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year is $1.3 million and $0.6 million, respectively.

In addition, the estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year totals $6.1 million. The estimated prior service cost and transition obligation for the other postretirement benefit plan that will be amortized from regulatory asset into net periodic benefit cost over the next fiscal year totals $3.8 million.

Additional Information

	Pension Benefits		*Other Benefits*	
(millions)	***2006***	*2005*	***2006***	*2005*
Increase in minimum liability included in other comprehensive income, net of tax	**$42.7**	$ (7.2)	$—	$—

The following table presents the incremental effect of adopting SFAS 158 on individual line items on the Consolidated balance sheets as of Dec. 31, 2006:

Increase (decrease) (millions)	*Before application of SFAS 158*	*SFAS 158 Adjustments*	*After application of SFAS 158*
Deferred income tax asset	$ 616.4	$ 13.8	$ 630.2
Long-term regulatory asset	139.4	91.9	231.3
Deferred charges and other assets	89.0	(1.7)	87.3
Total assets	7,251.4	104.0	7,355.4
Other current liabilities	—	14.2	14.2
Deferred credits and other liabilities	384.5	111.6	496.1
Total liabilities	5,500.6	125.8	5,626.4
Accumulated other comprehensive income	(8.7)	(21.8)	(30.5)
Total stockholder's equity	1,750.8	(21.8)	1,729.0
Total liability and stockholder's equity	7,251.4	104.0	7,355.4

Weighted-average assumptions used to determine benefit obligations at Sep. 30, the measurement date for the pension and other postretirement benefit plans

	Pension Benefits		*Other Benefits*	
	2006	*2005*	***2006***	*2005*
Discount Rate	**5.85%**	5.50%	**5.85%**	5.50%
Rate of compensation increase	**4.00%**	3.75%	**4.00%**	3.75%

Weighted-average assumptions used to determine net periodic benefit cost for years ended Dec. 31,

	Pension Benefits			*Other Benefits*		
	2006	*2005*	*2004*	***2006***	*2005*	*2004*
Discount Rate	**5.50%**	6.00%	6.00%	**5.50%**	6.00%	6.00%
Expected long-term return on plan assets	**8.50%**	8.75%	8.75%	**n/a**	n/a	n/a
Rate of compensation increase	**3.75%**	4.25%	4.25%	**3.75%**	4.25%	4.25%

The expected return on assets assumption was based on expectations of long-term inflation, real growth in the economy, fixed income spreads and equity premiums consistent with our portfolio, with provision for active management and expenses paid. The salary increase assumption was based on the same underlying expectation of long-term inflation together with assumptions regarding real growth in wages and company-specific merit and promotion increases. The discount rate assumption was based on a cash flow matching technique developed by our outside actuaries and a review of current economic conditions.

This technique matches the yields from high-quality (Aa-graded, non-callable) corporate bonds to the company's projected cash flows for the pension plan to develop a present value that is converted to a discount rate.

Healthcare cost trend rate	***2006***	*2005*	*2004*
Initial rate	**9.50%**	9.50%	10.50%
Ultimate rate	**5.00%**	5.00%	5.00%
Year rate reaches ultimate	**2014**	2013	2013

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(millions)	*1% Increase*	*1% Decrease*
Effect on total service and interest cost	$1.0	$(0.7)
Effect on postretirement benefit obligation	$7.4	$(6.0)

Asset Allocation

Pension plan assets (plan assets) are invested in a mix of equity and fixed income securities. 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.

Pension Plan Assets	*Target Allocation*	*Actual Allocation, End of Year*	
Asset Category		***2006***	*2005*
Equity securities	55-65%	**66%**	64%
Fixed income securities	35-45%	**34%**	36%
Total		**100%**	100%

Other Postretirement Benefit Plan Assets

There are no assets associated with TECO Energy's postretirement benefit plan.

Contributions

On Aug. 17, 2006, the President signed the Pension Protection Act of 2006 (the Act). While the company expects the Internal Revenue Service to issue regulations clarifying various terms of the Act, it generally introduces new minimum funding requirements beginning Jan. 1, 2008. The company's policy is to fund the plan at or above amounts determined by the company's actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. The company contributed $36.3 million to the plan in 2006, which included a $30 million contribution in addition to the $6.3 million minimum contribution required. TECO Energy expects to make a $30 million contribution in 2007 and average annual contributions of $22 million in 2008 – 2011.

The supplemental executive retirement plan is funded annually to meet the benefit obligations. In 2006, the company made a contribution of $1.6 million to this plan. In 2007, the company expects to make a contribution of about $1.4 million to this plan.

The following benefit payments, which reflect expected future service, as appropriate, are expected to be paid:

	Pension Benefits	*Other Postretirement Benefits*	
Expected benefit payments (millions):		*Gross*	*Expected Federal Subsidy*
2007	$ 44.8	$13.7	$(0.9)
2008	44.9	14.9	(1.0)
2009	45.7	15.9	(1.1)
2010	47.1	16.7	(1.2)
2011	49.0	17.4	(1.3)
2012-2016	257.4	90.4	(8.5)

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries (the Employers) that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. The company and its subsidiaries match up to 6% of the participant's payroll savings deductions. From Jan. 1, 2004 to Jun. 30, 2004, the company's matching contribution was 55% of eligible participant payroll savings deductions made in the form of the company's common stock. Effective Jul. 1, 2004, employer matching contributions were 30% of eligible participant contributions with additional incentive match of up to 70% of eligible participant contributions based on the achievement of certain operating company financial goals. For the years ended Dec. 31, 2006, 2005 and 2004, the company and its subsidiaries recognized expense totaling $9.0 million, $10.2 million and $6.6 million, respectively, related to the matching contributions made to this plan.

6. Short-Term Debt

At Dec. 31, 2006 and 2005, the following credit facilities and related borrowings existed:

Credit Facilities		*Dec. 31, 2006*			*Dec. 31, 2005*	
(millions)	*Credit Facilities*	*Borrowings Outstanding*[1]	*Letters of Credit Outstanding*	*Credit Facilities*	*Borrowings Outstanding*[1]	*Letters of Credit Outstanding*
Tampa Electric Company:						
5-year facility	$325.0	$13.0	$ —	$325.0	$120.0	$ —
1-year accounts receivable facility	150.0	35.0	—	150.0	95.0	—
TECO Energy:						
5-year facility	200.0	—	9.5	200.0	—	14.3
Total	$675.0	$48.0	$9.5	$675.0	$215.0	$14.3

(1) Borrowings outstanding are reported as notes payable.

These credit facilities require commitment fees ranging from 12.5 to 37.5 basis points. The weighted average interest rate on outstanding notes payable at Dec. 31, 2006 and 2005 was 5.45% and 4.45%, respectively.

TECO Energy Credit Facility

On Oct. 11, 2005, TECO Energy amended its $200 million bank credit facility, extending the maturity to Oct. 11, 2010 with optional extensions of up to two additional years with lenders' consent. The amended facility also allows TECO Energy to increase the facility size by up to $50 million with lenders' consent. The facility is secured by the stock of TECO Transport, which 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 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 Mar. 31, 2007, 5.00 times from Apr. 1, 2007 through Dec. 31, 2009 and 4.50 times from and after Jan. 1, 2010, 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. As of Dec. 31, 2006, the company was in compliance with both requirements. The 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 Company, to issue additional indebtedness in excess of a calculated level (initially $100 million), unless the indebtedness refinances currently outstanding indebtedness or meets certain other conditions. The facility also provides that, in the event the aggregate quarterly dividend payments on TECO Energy common stock were to equal or exceed a calculated amount (initially $50 million), subject to increase in the event TECO Energy issues additional shares of common stock, 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. The limitations described above on the ability to sell core assets, issue additional indebtedness and pay cash dividends will be released if TECO Energy achieves investment grade ratings and stable outlooks from both Moody's and Standard & Poor's.

Tampa Electric Company Credit Facility

On Oct. 11, 2005, Tampa Electric Company amended its $150 million bank credit facility, increasing the facility size to $325 million and extending the maturity to Oct. 11, 2010 with optional extensions of up to two additional years with lenders' consent. Tampa Electric Company terminated its $125 million 3-year bank credit facility. The amended facility also allows Tampa Electric Company to increase the facility size by up to $50 million with lenders' consent; and includes a $50 million sub-limit for letters of credit. The financial covenants were also amended to eliminate the requirement that Tampa Electric Company maintain a specified ratio of earnings before interest, taxes, depreciation and amortization (EBITDA) to interest, as defined in the agreement, and increase the permissible quarter-end debt to capital, as defined in the agreement, to 65%. As of Dec. 31, 2006, Tampa Electric Company was in compliance with this requirement.

Tampa Electric Company Accounts Receivable Facility

On Jan. 6, 2005, Tampa Electric Company and TEC Receivables Corp (TRC), a wholly-owned subsidiary of Tampa Electric Company, entered into a $150 million accounts receivable collateralized 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 entered into in connection with that facility, Tampa Electric Company sells and/or contributes to TRC all of its receivables for the sale of electricity or gas to its retail customers and related rights (the Receivables), with the exception of certain excluded receivables and related rights defined in the agreement, and assigns to TRC the deposit accounts into which the proceeds of such Receivables are paid. The Receivables are sold by Tampa Electric Company to TRC at a discount. Under the Loan and Servicing Agreement among Tampa Electric Company 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 has secured such borrowings with a pledge of all of its assets including the Receivables and deposit accounts assigned to it. Tampa Electric Company acts as Servicer to service the collection of the Receivables. TRC pays program and liquidity fees based on Tampa Electric Company's credit ratings. The receivables and the debt of TRC are included in the consolidated financial statements of TECO Energy and Tampa Electric Company.

On Dec. 22, 2006, Tampa Electric and TRC extended the maturity of Tampa Electric's $150 million accounts receivable collateralized borrowing facility from Jan. 5, 2006 to Dec. 21, 2007. As part of this extension, the EBITDA to interest covenant for Tampa Electric was eliminated. Tampa Electric's debt to capital covenant was increased from 60% to 65%.

7. Long-Term Debt

At Dec. 31, 2006, total long-term debt, excluding amounts currently due, had a carrying amount of $3,212.6 million and an estimated fair market value of $3,336.8 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 are 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 2007 through 2011 and thereafter are as follows:

Long-Term Debt Maturities For Continuing Operations

Dec. 31, (millions)	*2007*	*2008*	*2009*	*2010*	*2011*	*Thereafter*	*Total Long-term Debt*
TECO Energy							
Debt securities	$300.0	$—	$—	$400.0	$600.0	$ 600.0	$1,900.0
Junior subordinated notes	71.4	—	—	—	—	—	71.4
Tampa Electric	125.0	—	—	—	—	1,473.9	1,598.9
Peoples Gas	31.1	5.7	5.5	3.7	3.4	113.4	162.8
TECO Transport	110.6	—	—	—	—	—	110.6
TECO Guatemala	1.3	1.4	1.4	1.4	1.5	4.7	11.7
Total long-term debt maturities	$639.4	$7.1	$ 6.9	$405.1	$604.9	$2,192.0	$3,855.4

Debt Securities

TECO Energy – $100 million Senior Unsecured Floating Rate Notes

On Jun. 7, 2005, TECO Energy issued $100 million of senior unsecured Floating Rate Notes due 2010 through an institutional private placement. Net proceeds of $99.3 million were used to implement TECO Energy's debt redemption, refinancing, and hedging strategy. On Oct. 14, 2005, TECO Energy completed an exchange offer related to the Floating Rate Notes, thereby satisfying its obligations under a registration rights agreement.

TECO Energy – $200 million Senior Unsecured 6.75% Notes

On May 26, 2005, TECO Energy issued $200 million of senior unsecured 6.75% Notes due 2015. Net proceeds of $198.5 million were used in TECO Energy's debt redemption and refinancing plan. On Oct. 14, 2005, TECO Energy completed an exchange offer related to the 6.75% Notes, thereby satisfying its obligations under a registration rights agreement.

Tampa Electric – $250 million 6.55% Senior Unsecured Notes

On May 12, 2006, Tampa Electric Company issued $250 million aggregate principal amount of 6.55% Notes due May 15, 2036. The 6.55% Notes were sold at 99.375% of par to yield 6.598%. The offering resulted in net proceeds to Tampa Electric (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $246.0 million. Net proceeds were used to repay short-term debt and for general corporate purposes. Tampa Electric may redeem all or any part of the 6.55% Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of 6.55% Notes to be redeemed or (ii) the present value of the remaining payments of principal and interest on the 6.55% Notes to be redeemed, discounted at an applicable treasury rate (as defined in the applicable indenture), plus 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date.

Junior Subordinated Notes

Based on the provisions of FAS 150, the preferred securities issued by the company were reclassified and presented as long-term debt for external financial reporting purposes.

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 19** for additional discussion of the impact of FIN 46R.

Capital Trust I

In December 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 $18.2 million in 2005, and $17.0 million per year in 2004 and 2003. For 2005 and 2006, these distributions were reflected in interest expense.

On Dec. 20, 2005, TECO Energy completed the early redemption of $100 million aggregate liquidation amount of the 8.5% TRuPS of TECO Capital Trust I. On Dec. 20, 2006, TECO Energy completed the early redemption of the remaining outstanding $100 million aggregate liquidation amount of the 8.5% TRuPS of TECO Capital Trust I.

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. The equity units represented 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.

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**).

On Jan. 14, 2005, the final settlement rate was set for TECO Energy's remaining outstanding 7.209 million equity security units that were not tendered in the early settlement offer completed in August 2004. 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 of 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 (see **Note 22** for details regarding the redemption of these securities).

On Jan. 16, 2007, all $71.4 million outstanding trust preferred securities of TECO Capital Trust II were retired at maturity pursuant to their original terms.

At Dec. 31, 2006 and 2005, TECO Energy had the following long-term debt outstanding:

Long-term Debt (millions) Dec. 31,		*Due*	*2006*	*2005*
TECO Energy	Notes: 7.2% (effective rate of 7.38%) (1)	2011	**$600.0**	$600.0
	6.125% (effective rate of 6.32%) (1)	2007	**300.0**	300.0
	7% (effective rate of 7.09%) (1)	2012	**400.0**	400.0
	7.5% (effective rate of 7.85%) (1)(2)	2010	**300.0**	300.0
	6.75% (effective rate of 6.85%)(1)(2)	2015	**200.0**	200.0
	Floating rate 7.37% for 2006 and 6.25% for 2005 (effective rate 7.6% for 2006) (1)(2)(6)	2010	**100.0**	100.0
	Junior subordinated notes:			
	8.50% (3)	2041	**—**	106.2
	5.93% (Capital Trust II) (7)	2007	**71.4**	71.4
			1,971.4	2,077.6
Tampa Electric	Installment contracts payable: (4)			
	3.89% Variable rate for 2006 (effective rate of 4.13%) and fixed rate 6.25% for 2005 (6)	2034	**86.0**	86.0
	5.85% Refunding bonds (effective rate of 5.88%)(8)	2030	**75.0**	75.0
	5.1% Refunding bonds (effective rate of 5.72%)	2013	**60.7**	60.7
	5.5% Refunding bonds (effective rate of 6.29%)	2023	**86.4**	86.4
	4% (effective rate of 4.16%) (5)(8)	2025	**51.6**	51.6
	4% (effective rate of 4.17%) (5)(8)	2018	**54.2**	54.2
	4.25% (effective rate of 4.44%) (5)(8)	2020	**20.0**	20.0
	Notes: 6.875% (effective rate of 6.98%) (1)	2012	**210.0**	210.0
	6.55% (effective rate of 7.35%) (1)	2036	**250.0**	—
	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
			1,598.9	1,348.9
Peoples Gas System	Senior Notes: (1)(2) 10.35%	2007	**1.0**	1.8
	10.33%	2007-2008	**2.0**	3.0
	10.3%	2007-2009	**3.8**	4.8
	9.93%	2007-2010	**4.0**	5.0
	8%	2007-2012	**17.0**	19.1
	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
			162.8	168.7
TECO Guatemala				
	Note: 3% Fixed rate	2007-2014	**11.7**	13.0
			11.7	13.0
Other Unregulated	Dock and wharf bonds, 5% (4)	2007	**110.6**	110.6
			110.6	110.6
Unamortized debt discount, net			**(3.4)**	(2.4)
			3,852.0	3,716.4
Less amount due within one year			**639.4**	7.2
Total long-term debt			**$3,212.6**	$3,709.2

(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.
(3) These securities were redeemed on Dec. 20, 2006.
(4) Tax-exempt securities.
(5) The interest rate on these bonds was fixed for a five-year term on Aug. 5, 2002.
(6) Composite year-end interest rate.
(7) These notes were redeemed on Jan. 16, 2007.
(8) Certain pollution control equipment is pledged to secure these bonds.

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

On Jan. 1, 2006, TECO Energy adopted FAS 123R, requiring the company to recognize expense related to the fair value of its stock-based compensation awards. Prior to this, the company accounted for its share-based payments under APB 25 and related interpretations. The company adopted FAS 123R using the modified-prospective transition method. Under this transition method, compensation cost recognized beginning Jan. 1, 2006 includes compensation cost for all share-based payments granted prior to, but not yet vested as of, Dec. 31, 2005 (based on the grant-date fair market value estimated in accordance with the original provisions of FAS 123), and compensation cost for all share-based payments granted on or after Jan. 1, 2006 (based on the grant date fair market value estimated in accordance with the provisions of FAS 123R). Results for prior periods have not been restated.

TECO Energy has two share-based compensation plans (the Equity Plan and the Director Equity Plan), which are described below. The types of awards granted under these Plans include stock options, stock grants, time-vested restricted stock and performance-based restricted stock. Stock options are granted with an exercise price greater than or equal to the fair market value of the common stock on the date of grant and have a 10-year contractual term. Stock options for the Director Equity Plan vest immediately and stock options for the Equity Plan have graded vesting over a three-year period, with the first 33% becoming exercisable one year after the date of grant. Stock grants and time-vested restricted stock are granted at a price equal to the fair market value on the date of grant, with expense recognized over the vesting period, which is normally three years. Beginning in 2006, we granted time-vested restricted stock to directors that vests one-third each year. Performance-based restricted stock is granted with shares vesting after three years at 0% to 200% of the original grant, based on the total return of TECO Energy common stock compared to a peer group of utility stocks. Dividends are paid on all time-vested and performance-based restricted stock awards.

TECO Energy recognized total stock compensation expense for 2006 of $11.5 million pretax, or $7.1 million after-tax. Cash received from option exercises under all share-based payment arrangements was $7.3 million, $11.5 million and $5.7 million for the periods ended Dec. 31, 2006, 2005 and 2004 respectively. The aggregate intrinsic value of stock options exercised was $2.7 million, $5.5 million and $1.6 million for the periods ended Dec. 31, 2006, 2005 and 2004 respectively. The total fair market value of awards vesting during 2006 was $4.8 million, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2006, there was $10.5 million of unrecognized compensation cost related to all non-vested awards that is expected to be recognized over a weighted average period of two years. Prior to the adoption of FAS 123R, TECO Energy presented all tax benefits of deductions resulting from the exercise of stock options as operating cash flows in the Consolidated Condensed Statement of Cash Flows. Beginning on Jan. 1, 2006, the company changed its cash flow presentation in accordance with FAS 123R, which requires the cash flows resulting from excess tax deductions on share-based payments to be classified as financing cash flows.

Previously under APB 25, the company recognized or disclosed expenses for retirement-eligible employees over the nominal vesting period. Beginning Jan. 1, 2006 under FAS 123R, any new awards made to retirement-eligible employees are recognized immediately or over the period from the grant date to the date of retirement eligibility (non-substantive approach). The impact on net income for 2006 and 2005 of applying the nominal vesting period approach versus the non-substantive vesting period approach to awards granted prior to Jan. 1, 2006, for retirement-eligible employees would not have been material.

The fair market value of stock options is determined using the Black-Scholes valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of options granted is based on the Staff Accounting Bulletin No. 107 (SAB 107) simplified method of averaging the vesting term and the original contractual term; the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the option); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant.

The fair market value of performance-based restricted stock awards is determined using the Monte-Carlo valuation model, and the company uses the following methods to determine its underlying assumptions: expected volatilities are based on the historical volatilities; the expected term of the awards is based on the performance measurement period (which is generally three years); the risk-free interest rate is based on the U.S. Treasury implied yield on zero-coupon issues (with a remaining term equal to the expected term of the award); and the expected dividend yield is based on the current annual dividend amount divided by the stock price on the date of grant, with continuous compounding.

The value of time-vested restricted stock and stock grants are based on the fair market value of TECO Energy common stock at the time of grant.

Stock-based compensation expense reduced the Company's results of operations as follows:

(millions, except per share amounts)	*Dec. 31, 2006*
Income before income taxes	$11.50
Net income	$ 7.10
EPS - Basic:	$ 0.03
EPS - Diluted:	$ 0.03

The following table illustrates the effect on net income and earnings per share as if the company had applied the fair-value recognition provisions of FAS 123 to all share-based payments, prior to the adoption of FAS 123R. As all share-based payments have been expensed in 2006 in accordance with FAS 123R, no pro forma is required.

Pro Forma Stock-Based Compensation Expense

(millions, except per share amounts) *For the years ended Dec. 31,*	*2005*	*2004*
Net income from continuing operations		
As reported	$211.0	$(355.5)
Add: Unearned compensation expense(1)	3.4	3.2
Less: Pro forma expense(2)	6.8	8.8
Pro forma	$207.6	$(361.1)
Net income		
As reported	$274.5	$(552.0)
Add: Unearned compensation expense(1)	3.4	3.2
Less: Pro forma expense(2)	6.8	8.8
Pro forma	$271.1	$(557.6)
Net income from continuing operations – EPS, basic		
As reported	$ 1.02	$ (1.85)
Pro forma	$ 1.01	$ (1.87)
Net income from continuing operations – EPS, diluted		
As reported	$ 1.00	$ (1.85)
Pro forma	$ 0.99	$ (1.87)
Net income – EPS, basic		
As reported	$ 1.33	$ (2.87)
Pro forma	$ 1.31	$ (2.89)
Net income – EPS, diluted		
As reported	$ 1.31	$ (2.87)
Pro forma	$ 1.29	$ (2.89)

(1) Unearned compensation expense reflects the compensation expense of time-vested and performance-based restricted stock awards, after-tax.

(2) Includes compensation expense for stock options and performance-based restricted stock, determined using a fair-value based method, after-tax, plus compensation expense associated with time-vested restricted stock awards, determined based on fair market value at the time of grant, after-tax.

Assumptions	*2006*	*2005*	*2004*
Assumptions applicable to stock options			
Risk-free interest rate	**4.92%**	4.02%	4.04%
Expected lives (in years)	**6**	7	7
Expected stock volatility	**27.00%**	34.12%	34.09%
Dividend yield	**4.66%**	4.66%	5.67%
Assumptions applicable to performance-based restricted stock			
Risk-free interest rate	**4.92%**	3.74%	2.78%
Expected lives (in years)	**3**	3	3
Expected stock volatility	**18.22%**	45.31%	45.85%
Dividend yield	**4.64%**	4.49%	5.79%

Equity Plans

In April 2004, the company's 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. Under the 2004 Plan, the Compensation Committee of the Board of Directors authorized 10 million shares of TECO Energy common stock that may be awarded as 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"), 1.1 million, 0.9 million and 2.4 million stock options were granted to employees in 2006, 2005 and 2004, respectively, with weighted average fair values of $3.26, $3.93 and $2.80. In addition, 0.5 million, 0.4 million and 0.3 million shares of restricted stock were granted in 2006, 2005 and 2004, respectively, with weighted average fair values of $16.85, $21.57 and $14.80. In 2006, 17,962 shares of unrestricted common stock were granted with a weighted average fair value of $17.54. A summary of non-vested shares of restricted stock and stock options for 2006 under the Equity Plans are shown as follows:

Nonvested Restricted Stock and Stock Options-Equity Plans

	Nonvested Restricted Stock [(1)]		*Nonvested Stock Options*	
	Number of Shares (thousands)	*Weighted Avg. Grant Date Fair Value (per share)*	*Number of Shares (thousands)*	*Weighted Avg. Grant Date Fair Value (per share)*
Nonvested balance at Dec. 31, 2005	801	$18.16	2,712	$2.97
Granted	456	$16.85	1,089	$3.26
Vested	(276)	$14.28	(1,492)	$2.67
Forfeited	(11)	$20.95	(68)	$3.18
Nonvested balance at Dec. 31, 2006	970	$18.62	2,241	$3.30

(1) The weighted average remaining contractual term of restricted stock is 2 years.

Stock option transactions during 2006 under the Equity Plans are summarized as follows:

Stock Options – Equity Plans

	Number of Share (thousands)	*Weighted Avg. Option Price (per share)*	*Weighted Avg. Remaining Contractual Term (years)*	*Aggregate Intrinsic Value (millions)*
Outstanding balance at Dec. 31, 2005	9,694	$20.33		
Granted	1,089	$16.30		
Exercised	(594)	$11.93		
Forfeited/Expired	(383)	$22.67		
Outstanding balance at Dec. 31, 2006	9,806	$20.30	6	$15.3
Exercisable at Dec. 31, 2006	2,566	$12.82	7	$11.3
Available for future grant at Dec. 31, 2006	7,543			

(1) Option prices range from $11.09 to $31.58.

(2) Option prices range from $11.09 to $16.21.

As of Dec. 31, 2006, the 9.8 million options outstanding under the Equity Plans are summarized below:

Stock Options Outstanding				*Stock Options Exercisable*		
Range of Option Prices	*Option Shares (thousands)*	*Weighted Avg. Option Price*	*Weighted Avg. Remaining Contractual Life*	*Option Shares (thousands)*	*Weighted Avg. Option Price*	*Weighted Avg. Remaining Contractual Life*
\$11.09 - \$13.50	2,926	\$12.63	7 Years	2,285	\$12.40	7 Years
\$16.21 - \$18.87	1,927	\$16.29	9 Years	281	\$16.21	8 Years
\$21.25 - \$22.48	1,557	\$21.35	3 Years	0	\$0.00	—
\$23.55 - \$25.97	294	\$24.35	1 Year	0	\$0.00	—
\$27.56 - \$31.58	3,102	\$29.10	4 Years	0	\$0.00	—
Total	9,806	\$20.30	6 Years	2,566	\$12.82	7 Years

Director Equity Plan

In April 1997, the company's 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 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, administered by the Board of Directors, authorized 250,000 shares of TECO Energy common stock to be awarded as stock grants, stock options and/or stock equivalents.

Under the 1997 Plan, 26,875 shares of restricted stock were awarded in 2006, with a weighted average fair value of \$16.30. Restricted stock transactions for the year ended Dec. 31, 2006 under the 1997 Plan are summarized as follows:

Nonvested Restricted Stock — Director Equity Plans

	Number of Shares (thousands)	*Weighted Avg. Grant Date Fair Value (per share)*
Nonvested balance at Dec. 31, 2005	—	\$ —
Granted	27	\$16.30
Vested	—	\$ —
Forfeited	—	\$ —
Nonvested balance at Dec. 31, 2006[1]	27	\$16.30

(1) The weighted average remaining contractual term is 2 years.

Under the 1997 Plan, 35,000 stock options were granted in each of the years 2005 and 2004, with weighted average fair values of \$3.95 and \$2.90, respectively. In addition, 5,000 shares of unrestricted common stock were granted in each of the years 2005 and 2004, with weighted average fair values of \$16.21 and \$13.56, respectively. Stock option transactions during the year ended Dec. 31, 2006 under the 1997 Plan are summarized as follows:

Stock Options – Director Equity Plans [1]

	Number of Shares (thousands)	*Weighted Avg. Option Price (per share)*	*Weighted Avg. Remaining Contractual Term (years)*	*Aggregate Intrinsic Value (millions)*
Outstanding balance at Dec. 31, 2005	253	\$20.93		
Granted	—	\$ —		
Exercised	(12)	\$15.41		
Expired	(20)	\$23.63		
Outstanding balance at Dec. 31, 2006 [2]	221	\$20.99	5	\$0.3
Exerciseable at Dec. 31, 2006 [3]	83	\$13.54	7	\$0.3
Available for future grant at Dec. 31, 2006	186			

(1) Stock options granted under the Director Equity Plans vest immediately.

(2) Option prices range from \$11.09 to \$31.58 per share.

(3) Option prices range from \$11.09 to \$16.21 per share.

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy raised $4.4 million, $4.9 million and $5.1 million of common equity from this plan in 2006, 2005 and 2004, respectively.

Common Stock

On Jan. 18, 2005, TECO Energy issued 6.85 million shares of common stock as part of the final settlement for the remaining outstanding equity security units of TECO Capital Trust II; receiving approximately $180 million of proceeds from the settlement (see **Note 7**).

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**).

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. 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. At Dec. 31, 2004, the ESOP had no shares remaining to be allocated.

TECO Energy's contributions to the ESOP were $2.1 million in 2004. 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 prior years are as follows:

ESOP Expense

(millions) *For the years ended Dec. 31,*	*2004*
Interest expense	$0.3
Compensation expense	8.4
Dividends	(4.0)
Net ESOP expense	$4.7

Compensation expense was determined by the shares allocated method.

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 dividends received by the ESOP were used to pay debt service on the loan between TECO Energy and the ESOP.

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 for 2004. The tax benefit related to dividends paid to the ESOP for unallocated shares is an increase in retained earnings and was $0.1 million in 2004. 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, 2006, 2005 and 2004, 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 pension plans:

Comprehensive Income (loss)

(millions)	*Gross*	*Tax*	*Net*
2006			
Unrealized gain on cash flow hedges	$—	$—	$—
Less: Gain reclassified to net income	(0.5)	(0.2)	(0.3)
Gain (loss) on cash flow hedges	(0.5)	(0.2)	(0.3)
Additional minimum pension liability	69.5	26.8	42.7
Total other comprehensive income	$69.0	$26.6	$42.4
2005			
Unrealized gain on cash flow hedges	$ 7.3	$ 3.7	$ 3.6
Less: Gain reclassified to net income	(5.7)	(2.0)	(3.7)
Gain (loss) on cash flow hedges	1.6	1.7	(0.1)
Additional minimum pension liability	(11.8)	(4.6)	(7.2)
Total other comprehensive loss	$(10.2)	$(2.9)	$ (7.3)
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
Additional minimum pension liability	9.5	2.3	7.2
Total other comprehensive income	$17.7	$ 5.7	$12.0

(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 **Note 21** for additional details regarding the OCI balances for cash flow hedges.

Accumulated Other Comprehensive Income

(millions) Dec. 31,	*2006*	*2005*
Minimum pension liability adjustment [(1)]	**$—**	$(51.5)
Unrecognized pension losses and prior service costs [(2)]	**(22.0)**	—
Unrecognized other benefit losses, prior service costs and transition obligations [(3)]	**(8.6)**	—
Net unrealized gains from cash flow hedges [(4)]	**0.1**	0.4
Total accumulated other comprehensive loss	**$(30.5)**	$(51.1)

(1) Net of tax benefit of $32.5 million as of Dec. 31, 2005.
(2) Net of tax benefit of $13.9 million as of Dec. 31, 2006.
(3) Net of tax benefit of $5.5 million as of Dec. 31, 2006.
(4) Net of tax expense of $0.2 million and $0.4 million as of Dec. 31, 2006 and 2005, respectively.

11. Earnings Per Share

For the years ended Dec. 31, 2006, 2005 and 2004, stock options for 7.0 million shares, 5.4 million shares and 10.6 million shares, respectively, were excluded from the computation of diluted earnings per share due to their anti-dilutive effect. Additionally, 1.9 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 year ended Dec. 31, 2004 due to their anti-dilutive effect.

Earnings per Share

(millions, except per share amounts) *For the years ended Dec. 31,*		***2006***	*2005*	*2004*
Numerator				
Net income (loss) from continuing operations, basic		**$244.4**	$211.0	$(355.5)
Effect of contingent performance shares, net of tax		**(0.0)**	(2.0)	—
Net income (loss) from continuing operations, diluted		**244.4**	209.0	(355.5)
Discontinued operations, net of tax		**$1.9**	$63.5	$(196.5)
Net income (loss), diluted		**$246.3**	$272.5	$(552.0)
Denominator				
Average number of shares outstanding – basic		**207.9**	206.3	192.6
Plus: Incremental shares for unvested restricted stock and assumed conversions: Stock options at end of period, unvested unrestricted stock and contingent performance shares		**3.3**	5.4	—
Less: Treasury shares which could be purchased		**(2.5)**	(3.5)	—
Average number of shares outstanding – diluted		**208.7**	208.2	192.6
Earnings per share from continuing operations	Basic	**$ 1.18**	$ 1.02	$ (1.85)
	Diluted	**$ 1.17**	$ 1.00	$ (1.85)
Earnings per share from discontinued operations, net	Basic	**$ 0.01**	$ 0.31	$ (1.02)
	Diluted	**$ 0.01**	$ 0.31	$ (1.02)
Earnings per share	Basic	**$ 1.19**	$ 1.33	$ (2.87)
	Diluted	**$ 1.18**	$ 1.31	$ (2.87)

12. Commitments and Contingencies

Capital Investments

TECO Energy has made certain commitments in connection with its continuing capital expenditure program. These estimated capital investments total approximately $523 million for 2007.

For 2007, Tampa Electric expects to spend approximately $400 million, consisting of about $200 million to support system growth and generation reliability, approximately $14 million for distribution system reliability improvements, $13 million for transmission and distribution system storm hardening, $4 million for transmission system improvements to meet reliability requirements, $20 million for an additional natural gas pipeline to improve reliability of supply to the Bayside Power Station, $20 million for coal-fired generation capacity factor and availability improvements, $6 million to complete the addition of two combustion turbines at the Polk Power Station to meet its peaking generation capacity needs, $87 million for the addition of selective catalytic reduction (SCR) equipment at the Big Bend Station for NO_x control, and $34 million for other environmental compliance programs. At the end of 2006, Tampa Electric had outstanding commitments of about $198 million, for long-term capitalized maintenance agreements for its combustion turbines, materials and contractors for the SCR projects and for major maintenance outages at Big Bend Station.

Capital expenditures for PGS are expected to be about $50 million in 2007. Included in these amounts is an average of approximately $30 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 $70 million in 2007. Included in these amounts are new mine development projects to replace higher cost of production mines and position TECO Coal to increase production when coal markets improve at TECO Coal. Also included is normal renewal and replacement capital, including coal mining equipment, normal steel replacements, shipyard periods for oceangoing vessels, and inland river transportation equipment. TECO Coal had outstanding commitments of approximately $27 million, primarily for replacement of coal mining equipment at Dec. 31, 2006. TECO Transport had an outstanding commitment of $21 million for the construction of 50 replacement river barges, which is not included in the capital spending forecast as the company expects to charter these barges under an operating lease.

Legal Contingencies

At Dec. 31, 2006, the ultimate resolution of the following specific proceedings is uncertain and no liability has been reserved or can be estimated. At this time, the ultimate outcome of these proceedings is not expected to have a material adverse effect on the company's results of operations or financial condition.

Tampa Electric Transmission Litigation

In 2003, Tampa Electric completed a transmission project which required the placement of 95 foot and 125 foot transmission structures on public right of way in parts of residential neighborhoods, near the Egypt Lake subdivision in Tampa, Florida, in order to move electricity to the growth areas in the north-west part of its service area. The lawsuits for private nuisance (the Shaw, Acosta, and Alvarez cases) were filed shortly thereafter.

The Shaw plaintiffs' (39 parcels and approximately 55 individuals) appeal of the trial court's summary judgment denying plaintiffs' right to a mandatory injunction to remove the poles was decided in favor of the Company on Friday, Jan. 5, 2007. The Shaw case was set for trial on Jan. 8, 2007, but we were able to resolve the case and avoid the effect of a long and expensive trial. The legal principles in the Shaw case should apply to the remaining Acosta and Alvarez cases.

The Acosta plaintiffs are owners of 93 parcels and comprised of about 131 individuals. Many of these plaintiffs do not own property on the streets where the structures were placed. The case has been set for trial in May 2007.

There has been no activity in the Alvarez (substation) case, which involves only one parcel.

Grupo Arbitration

On Aug. 11, 2006, TPS International Power, Inc. (TPSI) received a favorable ruling from the Bogotá Chamber of Commerce Arbitration Tribunal in the Grupo-financed arbitration on behalf of itself and the Colombian trade union regarding a 1996 transaction that was never consummated related to the potential purchase and financing of a power plant. The Tribunal found no liability on the part of TPSI and found that it had no jurisdiction over TECO Energy or any of its subsidiaries. Accordingly, it did not become necessary to address the issue of damages.

Following the Arbitration Tribunal's finding of "no liability" as to TPSI on Aug. 11, 2006, the union filed a petition for annulment in the Ordinary courts on Aug. 31, 2006. The Union was ordered to file its detailed petition citing the record to substantiate its annulment claim on Oct. 12, but it failed to do so. The court appointed Tribunal issued a confirmation that the matter was closed. However, in early December, the Union filed papers asking the Tribunal to set aside its determination, that the Union's petition was barred due to the missed deadline, on the basis that the Tribunal's "Notification of the Oct. 12 date" was technically deficient. TPSI's counsel filed a reply on or about Dec. 14, 2006. There has not been any further activity.

Securities Class Action and Derivative Suits

Class Action Suit

After the consolidated Class Action Complaint brought by the "TECO Lead Plaintiff Group" in connection with TECO Energy's merchant power activities was dismissed without prejudice by the Court on Mar. 31, 2006, plaintiffs filed their further amended complaint to which TECO Energy and the individual defendants filed their motion to dismiss on Jul. 7, 2006 based on the same ground as raised in the prior motion, failure to plead loss causation. Defendants filed a renewed motion to dismiss, and on Oct. 10, 2006, the Court granted defendants' motion to dismiss in part, leaving only one remaining issue dealing with public statements relating to the status of the contracting plan for the approximately 6,000 MWs of merchant power then under construction in several states outside of Florida. On Oct. 30, 2006, the plaintiffs filed a Rule 54(b) motion asking the Court to enter a final judgment on the matters that were dismissed by its Oct. 10th order in order to appeal that portion of the order immediately, while maintaining the balance of the action in the district Court. The Court denied the Rule 54(b) motion. A mediation on the entire suit occurred on Feb. 16, 2007 whereby the company reached an agreement in principle to settle the shareholder securities class action lawsuit. See **Note 22** for more details.

Derivative Suit

On Apr. 5, 2006, the Hillsborough Circuit Court dismissed the derivative complaint filed against two named officers and the named directors without prejudice. Subsequently, the parties stipulated to dismiss with prejudice directors Penn and Whiting who were not members of the board during the relevant time period. Quarterly status reports of the Special Litigation Committee have been filed commencing Aug. 1, 2006. A mediation on the entire suit occurred on Feb. 16, 2007 whereby the company reached an agreement in principle to settle the derivative lawsuit. See **Note 22** for more details.

Other Issues

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 No. 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 their ultimate resolution 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 (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, 2006, Tampa Electric Company has estimated its ultimate financial liability to be approximately $12.3 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 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.

TECO Transport Storm Damage

In August and September 2005, TECO Transport subsidiaries sustained flood and wind damage, as well as business interruptions as a result of hurricanes Katrina and Rita. In 2006 and 2005, the company incurred $7.2 million pretax ($4.5 million after-tax) and $20.2 million pretax ($12.6 million after tax), respectively, of direct costs associated with these storms, including property damage, salvage, and cleanup expenses. The company carried wind and flood insurance for a majority of the property damaged and in 2006 and 2005, the company received $2.4 million pretax ($1.5 million after-tax) and $22.0 million pretax ($13.7 million after-tax), respectively, in insurance recoveries. As of Dec. 31, 2006, TECO Transport has settled all claims for terminal and marine damages related to the 2005 storms.

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.

Total rental expense for these operating leases, included in the Consolidated Statements of Income for the years ended Dec. 31, 2006, 2005 and 2004 was $30.0 million, $28.3 million and $32.3 million, respectively.

The following is a schedule of future minimum lease payments at Dec. 31, 2006 for all operating leases with non-cancelable lease terms in excess of one year:

Future Minimum Lease Payments of Operating Leases

Year ended Dec. 31:	*Amount (millions)*
2007	$ 28.1
2008	21.3
2009	18.9
2010	17.7
2011	16.0
Thereafter	87.4
Total minimum lease payments	$189.4

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 2004, $2.7 million of buy-out costs were amortized to expense. It was fully amortized by the end of 2004.

Guarantees and Letters of Credit

TECO Energy accounts for 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 the company determines 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, 2006 are as follows:

Letters of Credit and Guarantees

(millions)	*Maturing*					
Letters of Credit and Guarantees for the Benefit of:	*2007*	*2008*	*2009-2011*	*After 2011*	*Total*	*Liabilities Recognized at Dec. 31, 2006*
Tampa Electric						
Letters of credit	$—	$—	$—	$ 0.3	$ 0.3	$—
Guarantees:						
Fuel purchase/energy management [1][2]	—	—	—	20.0	20.0	2.0
	—	—	—	20.3	20.3	2.0
TECO Transport						
Letters of credit	—	—	—	2.5	2.5	—
TECO Coal						
Letters of credit	—	—	—	6.7	6.7	—
Guarantees: Other [2]	—	—		1.4 [1]	1.4	1.4
	—	—	—	8.1	8.1	1.4
Other unregulated						
Guarantees:						
Fuel purchase/energy management [1][2]	43.7	—	—	3.9	47.6	0.8
Total	$43.7	$—	$—	$34.8	$78.5	$4.2

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2011.

(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, 2006. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.

Financial Covenants

In order to utilize their respective bank facilities, TECO Energy and Tampa Electric Company must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, Tampa Electric Company and other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2006, TECO Energy, Tampa Electric Company and the other operating companies were in compliance with all required financial covenants. See **Liquidity, Capital Resources-Covenants in Financing Agreements in MD&A**.

13. Related Parties

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 $1.2 million, $1.3 million and $1.4 million for the years ended Dec. 31, 2006, 2005 and 2004, respectively, to Ausley McMullen, P.A. of which Mr. Ausley (a director of TECO Energy) is an employee. Other transactions were not material for the years ended Dec. 31, 2006, 2005 and 2004. No material balances were payable as of Dec. 31, 2006 or 2005.

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**, during the first quarter of 2005, the company revised internal reporting information for the purpose of evaluating, measuring and making decisions with respect to the components which previously comprised the "Other Unregulated" operating segment. The revised operating segment, "TECO Guatemala", is comprised of all Guatemalan operations. The remaining components are now included in "Other & eliminations". Prior period segment results have been restated to reflect the revised segment structure. In 2006, only historical data is presented for TWG Merchant as all merchant assets have been divested. Any residual results for 2006 are included in "Other and eliminations".

The information presented in the following table excludes all discontinued operations. See **Note 20** for additional details of the components of discontinued operations.

Segment Information (1)

(millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Transport*	*TECO Guatemala*	*TWG Merchant*	*Other & eliminations*	*Total TECO Energy*
2006								
Revenues - outsiders	$2,082.7	$577.6	$574.9	$205.1	$ 7.6 (6)	$ –	$ 0.2	$3,448.1
Sales to affiliates	2.2	–	–	103.4	–	–	(105.6)	–
Total revenues	2,084.9	577.6	574.9	308.5	7.6	–	(105.4)	3,448.1
Earnings from Unconsol. Affiliates	–	–	–	(0.3)	58.7	–	0.5	58.9
Depreciation and amortization	186.3	36.5	36.4	22.1	0.6	–	0.3	282.2
Total interest charges (2)	107.4	15.2	10.6	4.5	15.0	–	125.6	278.3
Internally allocated interest (2)	–	–	9.9	(1.4)	14.6	–	(23.1)	–
Provision (benefit) for taxes	80.3	18.8	35.6	10.9	8.7	–	(35.6)	118.7
Net income (loss) from continuing operations (2)	$ 135.9	$ 29.7	$ 78.8	$ 22.8	$ 37.6 (4)	$ –	$ (60.4) (3)	$ 244.4
Goodwill, net	$ –	$ –	$ –	$ –	$ 59.4	$ –	$ –	$ 59.4
Investment in unconsolidated affiliates	–	–	–	2.9	276.0	–	14.0	292.9
Other non-current investments	–	–	–	–	–	–	8.0	8.0
Total assets	4,813.7	765.2	389.4 (5)	333.9	424.6	–	635.0	7,361.8
Capital expenditures	$ 366.4	$ 54.0	$ 40.2	$ 16.5	$ 0.7	$ –	$ (22.1) (7)	$ 455.7
2005								
Revenues - outsiders	$1,744.3	$549.5	$505.1	$192.5	$ 7.7 (6)	$ 0.4	$ 10.6	$3,010.1
Sales to affiliates	2.5	–	–	85.7	–	–	(88.2)	–
Total revenues	1,746.8	549.5	505.1	278.2	7.7	0.4	(77.6)	3,010.1
Earnings from Unconsol. Affiliates	–	–	–	(0.3)	57.9	–	2.8	60.4
Depreciation and amortization	187.1	35.0	36.8	21.4	0.8	0.7	0.4	282.2
Total interest charges (2)	98.3	15.1	13.4	5.1	15.9	10.4	133.2	291.4
Internally allocated interest (2)	–	–	12.5	(0.6)	14.2	10.1	(36.2)	–
Provision (benefit) for taxes	90.6	18.5	64.9	8.1	(1.9)	(10.9)	(67.4)	101.9
Net income (loss) from continuing operations (2)	$ 147.1	$ 29.6	$115.4	$ 20.2	$ 40.4	$(14.6)	$ (127.1) (3)	$ 211.0
Goodwill, net	$ –	$ –	$ –	$ –	$ 59.4	$ –	$ –	$ 59.4
Investment in unconsolidated affiliates	–	–	–	2.9	274.0	–	20.2	297.1
Other non-current investments	–	–	–	–	–	–	8.0	8.0
Total assets	4,554.0	721.5	385.6 (5)	322.4	408.4	233.0	545.2	7,170.1
Capital expenditures	$ 203.5	$ 42.5	$ 24.1	$ 18.1	$ 0.2	$ 6.9	$ –	$ 295.3

Segment Information (1)

(millions)	*Tampa Electric*	*Peoples Gas*	*TECO Coal*	*TECO Transport*	*TECO Guatemala*		*TWG Merchant*	*Other & eliminations*		*Total TECO Energy*
2004										
Revenues - outsiders	$1,683.8	$417.2	$ 327.6	$173.4	$ 11.5	(6)	$ 7.6	$ 18.3		$2,639.4
Sales to affiliates	3.6	–	–	76.2	–		–	(79.8)		–
Total revenues	1,687.4	417.2	327.6	249.6	11.5		7.6	(61.5)		2,639.4
Earnings from Unconsol. Affiliates	–	–	–	0.2	45.7		(9.2)	(0.6)		36.1
Depreciation and amortization	180.9	34.1	36.3	21.9	0.8		1.0	0.9		275.9
Restructuring costs	–	0.7	–	–	–		0.5	–		1.2
Total interest charges (2)	95.8	15.2	11.2	4.7	14.7		50.7	130.6		322.9
Internally allocated interest (2)	–	–	11.1	(1.0)	14.3		50.7	(76.8)		(1.7)
Provision (benefit) for taxes	83.9	17.3	22.8	4.6	8.1		(314.0)	(67.8)		(245.1)
Net income (loss) from continuing operations (2)	$ 146.0	$ 27.7	$ 61.3	$ 10.2	$ 5.7	(4)	$(534.1)	$ (72.3)	(3)	$ (355.5)
Goodwill, net	$ –	$ –	$ –	$ –	$ 59.4		$ –	$ –		$ 59.4
Investment in unconsolidated affiliates	–	–	–	3.3	239.2		–	20.5		263.0
Other non-current investments	–	–	–	–	–		–	8.0		8.0
Total assets	4,167.3	671.1	413.9 (5)	315.4	363.6		2,736.8	304.3		8,972.4
Capital expenditures	$ 181.2	$ 38.7	$ 22.9	$ 20.2	$0.4		$ 0.2	$ 0.1		$ 263.7

(1) From continuing operations. All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for CCC and Frontera Generation Limited Partnership (Frontera) (formerly included in the TWG Merchant segment) and BCH Mechanical, Inc. (BCH) and other Energy Services operations (formerly included in the Eliminations & Other segment).

(2) Segment net income is reported on a basis that includes internally allocated financing costs. Internally allocated costs for 2006, 2005 and 2004 were at pretax rates of 8%, based on the average of each subsidiary's equity and indebtedness to TECO Energy assuming a 50/50 debt/equity capital structure. Internally allocated interest charges are a component of total interest charges.

(3) Net income for 2006 includes after-tax gains of $8.1 million on the sale of McAdams and $5.7 million on the sale of two steam turbines (original impairment recorded on TECO Guatemala in 2004, see (5) below). Net income for 2005 includes $46.7 million after-tax of debt extinguishment charges at TECO Energy parent (including a $19.8 million non-cash charge). Net income for 2004 includes an after-tax gain of $12.0 million on the sale of TECO Energy's interest in its propane business, partially offset by a non-cash $3.4 million after-tax asset impairment charge at TECO Solutions.

(4) Net income for 2004 includes a non-cash $12.8 million after-tax asset impairment charge related to certain steam turbines (see **Note 18**), $6.7 million after-tax charge related to the refinancing of the debt associated with the San José power station in Guatemala, and $17.4 million in after-tax charges associated with income taxes due to repatriation of cash from Guatemala following the refinancing.

(5) The carrying value of mineral rights as of Dec. 31, 2006, 2005, and 2004 was $20.6 million, $22.5 million and $25.0 million, respectively.

(6) Revenues for 2006, 2005 and 2004 are exclusive of entities deconsolidated as a result of FIN 46R and include only revenues for the consolidated Guatemalan entities.

(7) Included in other capital expenditures is a cash offset of $22.1 million, related to the sale of two combustion turbines by TPS McAdams to Tampa Electric. The corresponding capital expenditure is included in Tampa Electric's capital expenditures for 2006.

Tampa Electric provides retail electric utility services to more than 660,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for more than 332,000 residential, commercial, industrial and electric power generation customers in the state of Florida.

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 synthetic fuel facilities in 2000, whose production qualifies for the nonconventional fuels tax credit. In 2003, these synthetic fuel 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, with another 40.5% being sold in 2004, and an additional 8% sold in 2005.

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 Guatemala includes the equity investments in the San José and Alborada power plants, TEMSA, the equity investment in the Guatemalan distribution company, EEGSA, and the TECO Guatemala parent company. See below for further information on the deconsolidated Guatemala investments.

TWG Merchant's assets were entirely divested by the end of 2006.

Foreign Operations

TECO Guatemala, through its subsidiaries, owns independent power operations and other electric related investments in Guatemala. TECO Energy, through its equity investments, has a 100% ownership interest in the 120-megawatt San José power station and in transmission facilities in Guatemala. The plant provides capacity and energy under a U.S. dollar-denominated power sales agreement to EEGSA. TECO Energy, through its equity investments, also has a 96% ownership interest and operates the 78-megawatt Alborada power station that supplies capacity and energy to EEGSA, under a U.S. dollar-denominated power sales agreement. Prior to 2004, the subsidiaries that hold interests in the San José and Alborada power stations in Guatemala were consolidated entities. Subsequent to 2004, in accordance with the interpretation and application of the consolidation guidance established in FIN 46R regarding long-term power purchase agreements, TECO Energy could no longer consolidate these project companies and they are accounted for as equity investments (see **Notes 1** and **19** for additional details).

TECO Energy, through its subsidiaries, 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 Distribución Electrica Centroamericana Dos, S.A. owns an 80.9% interest in Empresa Electrica de Guatemala, S.A. - EEGSA, the largest electric distribution company in Central America, Inversiones Electricas Centroamericanas, S.A.-INVELCA, (the holding company for Guatemalan-based electric transmission, services and unregulated distribution companies) and Inmobiliaria y Desarrolladora Empresarial de America, S.A.-IDEAMSA, a real estate company, a 55% interest in Navega.com and subsidiaries in Central America, a telecommunications and data transmission carrier, and a 99.7% interest in Almacenaje y Manejo de Materiales Eléctricos, S.A., a company that manages, controls and sells electrical supplies and inventory materials.

The information presented in the following table provides select condensed financial information for the unconsolidated operations of the San José and Alborada power stations and the DECA II/EEGSA project.

TECO Guatemala Selected Financial Data

(millions)	*San José*	*Alborada*	*DECA II/EEGSA*[1]
2006			
Condensed income statement information			
Revenues	$ 84.2	$21.9	$648.4
Net income	26.2	14.7	81.1
TECO's equity in net income [3]	$ 26.2	$14.2	$ 18.3
Condensed balance sheet information			
Total assets	$196.9	$46.4	[2]
Total liabilities	90.6	14.8	[2]
TECO's equity and advances	$106.3	$31.6	$152.1
2005			
Condensed income statement information			
Revenues	$ 75.4	$21.0	$580.8
Net income	27.0	12.8	67.7
TECO's equity in net income [3]	$ 27.0	$12.3	$ 18.6
Condensed balance sheet information			
Total assets	$201.1	$49.5	$983.9
Total liabilities	99.1	19.5	436.6
TECO's equity and advances	$100.3	$30.1	$155.5
2004			
Condensed income statement information			
Revenues	$ 70.1	$20.5	$639.6
Net income	17.6	11.8	42.5
TECO's equity in net income	$ 17.6	$11.4	$ 16.2
Condensed balance sheet information			
Total assets	$200.5	$55.8	$926.4
Total liabilities	114.1	28.0	432.2
TECO's equity and advances	$ 84.2	$24.4	$138.2

(1) 2006 information is based on management's estimates, derived from information provided by EEGSA and its related affiliates. Final 2006 income statement information for the DECA II/EEGSA project will be received during the first quarter of 2007 and true-up adjustments will be made at that time. These adjustments are not expected to be material.

(2) EEGSA and its related affiliates had not provided balance sheet information prior to the company's filing date.

(3) Total net income from the entire Guatemalan segment was $37.6 million, $40.4 million and $5.7 million for 2006, 2005 and 2004, respectively. The above selected income information includes only the project level information as stated above and does not include certain parent-based oversight costs and U.S. taxes.

15. Asset Retirement Obligations

TECO Energy accounts for asset retirement obligations under FAS 143. 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 estimated 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.

In the fourth quarter of 2005, Tampa Electric recorded an increase to net property, plant and equipment of $3.6 million (net of accumulated depreciation of $0.4 million), an increase to regulatory assets of $2.7 million and an increase to asset retirement obligations of $18.3 million (including $12.1 million reclassified from a regulatory liability), in accordance with FIN 47.

For the years ended Dec. 31, 2006, 2005 and 2004, TECO Energy recognized $1.5 million, $1.6 million, and $2.0 million of accretion expense, respectively, associated with asset retirement obligations.

Reconciliation of beginning and ending carrying amount of asset retirement obligations:

	Dec. 31,	
(in millions)	***2006***	*2005*
Beginning Balance	**$42.2**	$23.6
Additional liabilities	**3.5**	1.1
Liabilities settled	**(2.4)**	(2.4)
Accretion expense	**1.5**	1.6
Revisions to estimated cash flows	**7.3**	—
Implementation of FIN 47	—	18.3
Other[1]	**0.6**	—
Ending Balance	**$52.7**	$42.2

(1) Accretion expense reclassed as a deferred regulatory asset.

During 2006, estimated cash flows used in determining the recognized asset retirement obligations were adjusted by $7.3 million at Tampa Electric Company. The amount is related to the increased cost of removal of materials used for the generation and transmission of power.

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.

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

Sale of Properties

During the year ended Dec. 31, 2006, the company sold two lots adjacent to the corporate office in downtown Tampa, Florida to third party real estate developers. The sales included total proceeds of $15.0 million and resulted in pretax gains of $6.4 million. Included in each sale agreement were the ability to lease the properties until construction commenced and options to repurchase the properties after a certain period of time in the event the lots were not developed. As a result of this continuing involvement, the total gain is being deferred until such time as the continuing involvement terminates.

Sale of Steam Turbines

In July of 2006, the company sold a steam turbine generator located in Maricopa County, Arizona to a third party for a net after-tax gain of $2.6 million. In December of 2006, the company sold a second steam turbine generator also located in Maricopa County, Arizona to a third party for a net after-tax gain of $3.1 million

Sale of TPS McAdams, LLC

On Jun. 23, 2006, TPS McAdams, LLC, an indirect subsidiary of TECO Energy was sold to Von Boyett Corporation for $1.2 million in cash. The assets of TPS McAdams, LLC had been impaired in 2004 to an estimate of salvage value, which included allowances for potential future site restoration costs. In the first quarter of 2006, TPS McAdams, LLC sold the combustion turbines at the site to Tampa Electric Company at the book value contemplated in the salvage estimate. The sale and transfer of TPS McAdams, LLC, including its remaining assets and any potential site restoration costs at terms better than contemplated in the salvage estimate, resulted in a pretax gain of $10.7 million ($8.1 million after-tax) being recognized in continuing operations.

Sale of TECO Thermal

In May of 2006, the company sold the assets of TECO Thermal, an indirect subsidiary of TECO Energy, to a third party. Total proceeds on the sale were $8.1 million and resulted in an after-tax gain of $0.5 million.

Dell Power Station

On Aug. 16, 2005, an indirect subsidiary of TECO Energy completed the sale of substantially all of its assets, including the Dell Power Station, to Associated Electric Cooperative, Inc., a Missouri electric cooperative, for $75 million. The sale resulted in a pretax gain of $23.2 million ($14.9 million after-tax). TECO Energy retained certain other operating liabilities totaling $11.0 million pretax ($7.1 million after-tax). The net after-tax impact of $7.8 million is included in continuing operations.

Union and Gila River Project Companies

On Jun. 1, 2005, the company completed the sale and transfer of ownership of its indirect subsidiaries, Union Power Partners, L.P., Panda Gila River, L.P., Trans-Union Interstate Pipeline, L.P., and UPP Finance Co., LLC, owners of the Union and Gila River power stations in Arkansas and Arizona, respectively (collectively, the Projects) to an entity owned by the Projects' lenders in the manner set forth in the Projects' confirmed Joint Plan of Reorganization (the Plan). In connection with the transfer and the related release of liability, the company and its indirect subsidiaries paid an aggregate of $31.8 million, consisting of $30.0 million to the Project's lenders as consideration for release of liability and $1.8 million as reimbursement of legal fees for two non-consenting lenders in the recently concluded Chapter 11 proceeding.

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., majority owned at that time by 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. During the third quarter of 2005, terms of the sale were modified from a sale of assets to a sale of stock. This modification resulted in an additional after-tax loss of $1.4 million on tax-related assets. The results of BCH are reflected in discontinued operations for all periods presented (see **Note 20**).

PLC/TIE

On Aug. 30, 2004, a TWG Merchant 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.

Frontera

On Dec. 22, 2004, subsidiaries of TWG Merchant completed the sale of their respective 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. As a result of the sale, a pretax loss of $42.1 million ($27.0 million after tax) was recorded. See **Note 20** 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 Sep. 30, 2004.

On Apr. 19, 2005, an indirect subsidiary of TECO Energy completed the sale of its membership interests in CCC, the owner of the Commonwealth Chesapeake Power Station in Virginia, to an affiliate of Tenaska Power Fund, L.P. Net proceeds from the sale were $90.2 million after consideration for the value of working capital less transaction-related expenses. As a result of asset impairments recorded in the fourth quarter 2004, the sale transaction resulted in a pretax gain of $0.9 million ($0.6 million after-tax) upon close. The transaction terms provided for certain ordinary and customary post-closing adjustments to working capital items, which were completed as expected with no material adjustments in the third quarter of 2005. CCC's results are reflected in discontinued operations for all periods presented (see **Note 20**).

TECO Propane Ventures

In the first quarter of 2004, US Propane, LLC, in which TECO Propane Ventures owned an interest, 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 became 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.

BGA

Effective Jan. 1, 2004, the company completed the sale of TECO BGA 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% indirect interest in Pike Letcher Synfuel, LLC (PLS), which owns synthetic fuel production facilities located at TECO Coal's operations in eastern Kentucky. In May 2004, TECO Coal sold an additional 40.5% of its membership interest in the synthetic fuel facilities and another 8% in July 2005, under similar terms as the first transaction. On Dec. 29, 2005, the agreements with the investors were amended to permit the curtailment of synthetic fuel production when oil prices are above certain thresholds and to allow TECO the right, but not the obligation, to cause PLS to reduce or halt synthetic fuel production should estimates for crude oil prices reach certain levels. This amendment also allowed for the release of $20 million of the $50 million restricted cash that has been held in escrow. Generally, revenue is recognized as the monthly installments are received. Because the purchase price for this sale, as well as the other sales of ownership interests, is related to the value of tax credits generated through December 2007, it is subject to a reduction to the extent the credit is limited due to the average domestic oil price for a particular year exceeding the benchmark designated for that year by the Department of Energy. In addition to retaining a 2% membership interest in the facilities, TECO Coal has continued to supply the feedstock and operate the facilities.

17. Goodwill and Other Intangible Assets

FAS 141 *Business Combinations*, requires all business combinations be accounted for using the purchase method of accounting. Under FAS 142 *Goodwill and Other Intangible Assets*, goodwill is not 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 during the fourth quarter, 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.

At Dec. 31, 2006, the company has $59.4 million of goodwill on its balance sheet, which is reflected in the TECO Guatemala segment. In conducting its annual impairment assessment, the company determined the fair value of the Guatemalan reporting unit supported the goodwill. The balance of goodwill arose from the purchase of multiple entities as a result of the company's investment in its operations in Guatemala. The amount remained unchanged from Dec. 31, 2005.

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. This charge is reflected in discontinued operations. See **Note 20** 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). For the year ended Dec. 31, 2004, the company recognized amortization expense of $0.2 million.

18. Asset Impairments

The company accounts for asset impairments in accordance with FAS 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* (FAS 144). FAS 144 requires that long-lived assets be tested for recoverability whenever events or changes in circumstances indicate that its carrying value may not be recoverable. As of Dec. 31, 2006, the carrying value of all long lived assets was determined to be recoverable. No adjustments for asset impairments were necessary.

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 20** 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 December 2004 (see **Note 16**). Also as a result of this review, management determined as of Dec. 31, 2004 there existed a lower probability that the remaining merchant investments would be held for the long term resulting in the impairments to the Dell, McAdams, and Commonwealth Chesapeake power stations described below. During 2005, an additional impairment was made to McAdams, also discussed below.

In the fourth quarter of 2005, a pretax impairment charge of $3.2 million ($2.1 million after tax) was recognized related to the company's investment in the McAdams power station. The reduction in fair value resulted from an updated strategic review of the potential salvage options (including asset retirement obligations as a result of exiting the facility) following the decision to sell the combustion turbines and certain ancillary equipment to Tampa Electric.

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 ($3.1 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 TECO Energy's Consolidated Statements of Income.

On Aug. 30, 2004, a TWG Merchant 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. The impairment charge and results of operations are reflected in discontinued operations (see **Note 20**).

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. Although the steam turbine impairment charges were not directly related to TECO Guatemala, they are reflected in the TECO Guatemala segment for accounting purposes, due to the revised segment reporting described in **Note 1**.

In the first quarter of 2004, Litestream Technologies, LLC, an entity in which TECO Fiber, a subsidiary of TECO Solutions, held 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 and eliminations segment.

Additional impairment charges recognized in 2004 included a $2.4 million pretax ($1.5 million after tax) valuation adjustment at 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.

19. 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 variable interest entities (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 in 2003 without material impact. As of Jan. 1, 2004, FIN 46R was adopted for the remaining VIEs as described below.

Prior to the adoption of FIN 46, the company formed TCAE to own and construct the Alborada Power Station and the company formed CGESJ to own and construct the San José Power Station. Both power stations are located in Guatemala and both projects obtained long-term power purchase agreements (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 CGESJ due to the terms of the PPAs. 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 TECO Energy's Consolidated 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 TECO Energy's Consolidated Balance Sheet. The results of operations for the two projects are classified as "Income (loss) from Equity Investments" in TECO Energy's Consolidated Statements of Income since the date of deconsolidation. TECO Energy's estimated maximum loss exposure is its equity investment of approximately $118.5 million in these entities. (See **Note 14** for additional financial information related to these projects).

Pike Letcher Synfuel, LLC was established as part of the Apr. 1, 2003, sale of TECO Coal's synthetic fuel production facilities. While TECO Energy's maximum loss exposure in this entity is its investment of approximately $8.2 million, the company could lose potential earnings and could incur losses related to the production costs for the future production of synthetic fuel, in the event that such production creates 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 or fuel tax credits are reduced or eliminated due to high oil prices. 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 replacement 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.

In 1992, a subsidiary of the company, Hardee Power Partners, Ltd. 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 Golder 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**.

TECO Properties formed a limited liability company (Hernando Oaks, LLC) with a project developer to buy and develop land in Hernando County, Florida into a residential golf community. Hernando Oaks, LLC met the definition of a VIE, due to subordinated financial support in the form of a guarantee by the company on behalf of Hernando Oaks, LLC. 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. Hernando Oaks, LLC was sold during 2005.

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., met the definition of a VIE 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. The company consolidated TECO AGC, Ltd. as of Jan. 1, 2004 with no material increase in assets or liabilities. TECO AGC, Ltd was sold in 2004.

20. Discontinued Operations and Assets Held for Sale

Union and Gila River Project Companies (TPGC)

On Jun. 1, 2005, the company completed the previously announced sale and transfer of ownership of its indirect subsidiaries Union Power Partners, L.P., Panda Gila River, L.P., Trans-Union Interstate Pipeline, L.P., and UPP Finance Co., LLC, owners of the Union and Gila River power stations in Arkansas and Arizona, respectively (collectively, the Projects) to an entity owned by the Projects' lenders in the manner set forth in the Projects' confirmed Joint Plan of Reorganization. In connection with the transfer and the related release of liability, the company and its indirect subsidiaries paid an aggregate of $31.8 million, consisting of $30.0 million to the Project's lenders as consideration for the release of liability and $1.8 million as reimbursement of legal fees for two non-consenting lenders in the Chapter 11 proceeding. As a result of the transaction, the company recorded a non-cash, pretax gain of $117.7 million ($76.5 million after tax), which is reflected in discontinued operations. Through the May 31, 2005 effective date of the transfer to the lending group, the net equity of the Projects was reduced by accumulated unfunded operating losses primarily related to unpaid accrued interest expense on the Projects. As a result of the recognition of these subsequent losses, the book value of the assets was less than the book value of non-recourse project financing at the effective date of the sale and transfer to the lending group. Accordingly, the gain on the disposition represents the transfer of equity in the projects and the related non-recourse debt and other liabilities in excess of the asset value of the projects.

As an asset held for sale, the assets and liabilities that were expected to be transferred as part of the sale, as of Dec. 31, 2004, were reclassified in the balance sheet. The results from operations and the gain on sale have been reflected in discontinued operations for all periods presented. The following table provides selected components of discontinued operations for the Union and Gila River project companies.

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

(millions) *For the years ended Dec. 31,*	***2006***	*2005*	*2004*
Revenues	**$ —**	$109.1	$510.7
Loss from operations	—	(23.0)	(33.5)
Loss on joint venture termination	—	—	—
Gain on sale before tax	—	117.7	—
Income (loss) before provision for income taxes	—	90.0	(144.9)
Provision (benefit) for income taxes	—	24.9	(48.9)
Net income (loss) from discontinued operations	**$ —**	$65.1	$ (96.0)

Interest Expense

In accordance with the Statement of Position 90-7, Financial Reporting by Entities in Reorganization Under the Bankruptcy Code (SOP 90-7), and the provisions of the U.S. bankruptcy code and the Joint Plan, interest expense on the Project entities' non-recourse debt subsequent to the bankruptcy filing was not to be paid and was therefore not recorded. Had the bankruptcy proceeding not occurred, the Project entities would have recorded additional pretax interest expense of $44.3 million during 2005, which would have been reported in income (loss) from discontinued operations.

Other Transactions

Components of income from discontinued operations include CCC (sold in 2005), BCH Mechanical (sold in 2005), Frontera (sold in 2004), Prior Energy (sold in 2004), TECO BGA (sold in 2004) and TECO AGC (sold in 2004). See **Note 16** for additional details related to these sales. Results for 2004 include a $2.4 million pretax ($1.5 million after-tax) asset impairment charge at TECO Solutions related to a district cooling plant.

At Dec. 31, 2005, assets and liabilities held for sale includes TECO Thermal, an investment of TECO Solutions. For all periods presented, the results from operations of each of these entities are presented as discontinued operations on the income statement. There are no assets held for sale as of Dec. 31, 2006.

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,*	***2006***	*2005*	*2004*
Revenues	**$0.8**	$10.6	$ 41.7
Income (loss) from operations	**$1.5**	$ (0.3)	$(110.1)
(Loss) gain on sale	**$0.8**	$ (2.1)	$ (43.4)
Income (loss) before provision for income taxes (1)	**$2.3**	$ (1.8)	$(149.1)
Provision (benefit) for income taxes	**0.4**	(0.2)	(48.6)
Net income (loss) from discontinued operations (1)	**$1.9**	$ (1.6)	$(100.5)

(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 were at a pretax rate of 8%, based on the average investment in each subsidiary. There were no internally allocated financing costs to discontinued operations in 2006 or 2005.

Revenues

Discontinued operations for 2005 and 2004 include revenues for energy marketing operations at Prior Energy, which 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, 2005 and 2004 were ($0.1) million and $128.0 million, respectively. There were no revenues for Prior Energy in 2006.

(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.

Assets and Liabilities

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

(millions) Dec. 31,	***2006***	*2005*
Net property, plant and equipment	**$—**	$6.4
Other non-current assets	—	1.6
Total assets held for sale	**$—**	$8.0

Liabilities associated with assets held for sale

(millions) Dec. 31,	***2006***	*2005*
Current liabilities	**$—**	$1.8
Total liabilities associated with assets held for sale	**$—**	$1.8

21. 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 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 Merchant, prior to the transfer of the Union & Gila power plants in June 2005;
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Transport and TECO Coal; and
- To limit the exposure to synthetic fuel 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.

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 FAS 138, *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 the instruments' settlement. 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, 2006 and 2005, respectively, TECO Energy and its affiliates had derivative assets (current and non-current) totaling $7.2 million and $68.9 million, and liabilities (current and non-current) totaling $74.0 million and $0.3 million. At Dec. 31, 2006 and 2005, accumulated other comprehensive income (AOCI) included $0.1 million and $0.4 million, respectively, of unrealized after-tax gains, representing the fair value of cash flow hedges whose underlying transactions will occur within the next 12 months. 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, 2006, 2005 and 2004, 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 $0.5 million, $5.7 million and $1.2 million, respectively. Amounts reclassified from OCI were primarily related to cash flow hedges for physical purchases of fuel oil at TECO Transport. For these types of hedge relationships, the gain on the derivative at settlement is reclassified from OCI to earnings, which is offset by the increased cost of spot purchases for fuel oil.

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. 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) from OCI to income from discontinued operations in 2004 (see **Note 20**). Gains and losses on these derivative instruments, subsequent to the discontinuation of hedge accounting treatment, were recorded in earnings.

At Dec. 31, 2006, TECO Energy subsidiaries had derivative assets totaling $7.0 million for transactions related to crude oil options 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, 2006, 2005 and 2004, the company recognized gains on marked-to-market derivatives of $2.9 million, $0.5 million and $0.8 million, respectively.

22. Subsequent Events

TECO Capital Trust II

On Jan. 16, 2007, all $71.4 million outstanding subordinated notes were retired by TECO Energy pursuant to their original terms. This caused the retirement of $57.5 million trust preferred securities of TECO Capital Trust II, pursuant to their original terms.

Settlement of the Securities Class Action and Derivative Suits

During the scheduled mediation on Feb. 16, 2007, the company reached an agreement in principle to settle the shareholder securities class action lawsuit ("class action suit") and, at the same time, the company's officers and directors reached a similar agreement to settle the shareholder derivative lawsuit ("derivative suit") pending in the Federal District Court in Tampa, Florida and the Florida State Circuit Court for the 13th Circuit in Tampa, respectively, both relating to merchant power activities during 2001 and 2002. The settlement in the class action suit will resolve all issues in the case against the company and the two individual defendants, including the one remaining category of claims that was not dismissed by the federal court's order issued on Oct. 10, 2006, in response to the company's motion to dismiss. The settlement in the derivative suit will also resolve all claims against the directors and officers. Under the terms of the settlements, the company's primary insurance carrier will pay the settlement amount of $17.4 million to completely resolve the class action suit. In the derivative suit, the company will institute certain corporate governance changes along with those previously instituted since the pendency of the suit and the company's insurance carrier will pay the plaintiff's attorney's fees in the amount of $400,000. All defendants in both cases will receive releases of all claims, and both lawsuits will be dismissed with prejudice. The settlement is subject to various conditions, including the execution of definitive agreements and releases, approval by the applicable federal or state court and the appropriate shareholder notices. See **Note 12.**

23. Quarterly Data (unaudited)

Financial data by quarter is as follows:

(millions, except per share amounts) *Quarter ended*	*Dec. 31*	*Sep. 30*	*Jun. 30*	*Mar. 31*
2006				
Revenues	$826.2	$922.9	$862.6	$836.4
Income from operations	$ 78.4	$135.3	$118.3	$ 86.2
Net income				
Net income from continuing operations	$ 48.4	$ 79.7	$ 61.1	$ 55.2
Net income	$ 48.9	$ 79.7	$ 62.5	$ 55.2
Earnings per share (EPS) — basic				
EPS from continuing operations	$ 0.23	$ 0.38	$ 0.29	$ 0.27
EPS	$ 0.23	$ 0.38	$ 0.30	$ 0.27
Earnings per share (EPS) — diluted				
EPS from continuing operations	$ 0.23	$ 0.38	$ 0.29	$ 0.26
EPS	$ 0.23	$ 0.38	$ 0.30	$ 0.26
Dividends paid per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.19
Stock price per common share (1)				
High	$ 17.50	$ 16.20	$ 16.75	$ 16.75
Low	$ 15.57	$ 14.86	$ 14.40	$ 15.97
Close	$ 17.23	$ 15.65	$ 14.94	$ 16.12

Quarter ended	*Dec. 31*(3)	*Sep. 30*	*Jun. 30*(2)	*Mar. 31*
2005				
Revenues	$770.0	$836.4	$719.0	$684.7
Income from operations	$ 83.5	$100.6	$ 92.7	$ 79.9
Net income				
Net income from continuing operations	$ 52.6	$ 94.5	$ 12.4	$ 51.5
Net income	$ 52.0	$ 94.6	$ 95.2	$ 32.7
Earnings per share (EPS) — basic				
EPS from continuing operations	$ 0.25	$ 0.46	$ 0.06	$ 0.25
EPS	$ 0.25	$ 0.46	$ 0.46	$ 0.16
Earnings per share (EPS) — diluted				
EPS from continuing operations	$ 0.24	$ 0.45	$ 0.04	$ 0.25
EPS	$ 0.24	$ 0.45	$ 0.44	$ 0.16
Dividends paid per common share	$ 0.19	$ 0.19	$ 0.19	$ 0.19
Stock price per common share (1)				
High	$ 18.25	$ 19.30	$ 19.05	$ 16.50
Low	$ 15.72	$ 17.15	$ 15.30	$ 14.87
Close	$ 17.18	$ 18.00	$ 18.91	$ 15.68

(1) Trading prices for common shares
(2) Second quarter 2005 results include a debt extinguishment charge.
(3) Fourth quarter 2005 results include an impairment charge 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, 2006 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, 2006.

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, 2006 as stated in their report below.

Report of Independent Registered Certified Public Accounting Firm

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

We have completed integrated audits of TECO Energy, Inc.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, 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 and Financial Statement Schedules

In our opinion, the consolidated financial statements listed in the index appearing under Item 8 present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedules listed in the index appearing under Item 8 present fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedules 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 Note 2 to the financial statements, the Company changed its method of accounting for stock-based compensation as of January 1, 2006 and its method of accounting for its defined benefit pension and other postretirement plans as of December 31, 2006.

Internal Control Over Financial Reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2006 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 December 31, 2006, 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
February 27, 2007

Selected Financial Data

(millions, except per share amounts)					
Years ended Dec. 31,	***2006***	*2005*	*2004*	*2003*	*2002*
Revenues [1]	**$3,448.1**	$3,010.1	$2,639.4	$2,562.9	$2,487.3
Net income (loss) from continuing operations [1]	**$ 244.4**	$ 211.0	$ (355.5)	$ 100.7	$ 265.4
Net income (loss) from discontinued operations [1][2]	**1.9**	63.5	(196.5)	(1,005.8)	64.7
Cumulative effect of change in accounting principle, net	—	—	—	(4.3)	—
Net income (loss)	**$ 246.3**	$ 274.5	$ (552.0)	$ (909.4)	$ 330.1
Total assets	**$7,361.8**	$7,170.1	$8,972.4	$9,964.3	$8,738.2
Long-term debt	**$3,212.6**	$3,709.2	$3,880.0	$4,392.6	$3,324.3
Earnings per share (EPS) – basic;					
From continuing operations [1]	**$ 1.18**	$ 1.02	$ (1.85)	$ 0.56	$ 1.73
From discontinued operations [1]	**0.01**	0.31	(1.02)	(5.59)	0.42
From cumulative effect of change in accounting principle	—	—	—	(0.02)	—
EPS basic	**$ 1.19**	$ 1.33	$ 2.87)	$ (5.05)	$ 2.15
Earnings per share (EPS) – diluted;					
From continuing operations [1]	**$ 1.17**	$ 1.00	$ (1.85)	$ 0.56	$ 1.73
From discontinued operations [1]	**0.01**	0.31	(1.02)	(5.58)	0.42
From cumulative effect of change in accounting principle	—	—	—	(0.02)	—
EPS diluted	**$ 1.18**	$ 1.31	$ (2.87)	$ (5.04)	$ 2.15
Dividends paid per common share	**$ 0.76**	$ 0.76	$ 0.76	$ 0.93	$ 1.41

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in Note 20 to the TECO Energy Consolidated Financial Statements.

(2) 2004 and 2003 include impairment charges of $558.6 million and $100.1 million, respectively. See Notes 17 and 18 to the TECO Energy Consolidated Financial Statements.

TECO ENERGY

March 21, 2007

Notice of Annual Meeting of Shareholders

Date: **May 2, 2007**

Time: **10:00 a.m.**

Place: **The University of Tampa**
Vaughn Center
401 W. Kennedy Blvd.
Tampa, Florida 33606

Purpose: We are holding the annual meeting of the shareholders of TECO Energy, Inc. for the following purposes:

1. To elect four directors.
2. To ratify the selection of our 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 23, 2007 will be entitled to vote at the meeting.

Even if you plan to attend the meeting, please either: (i) mark, sign and date the enclosed proxy card and return it promptly in the accompanying envelope or (ii) 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,

David E. Schwartz
Corporate Secretary

TECO ENERGY, INC.
P.O. Box 111 Tampa, Florida 33601 (813) 228-1111

Table of Contents

Proxy Statement

TECO Energy, Inc.

P.O. Box 111, Tampa, FL 33601

We are soliciting proxies on behalf of our Board of Directors to be voted at the May 2, 2007 Annual Meeting of Shareholders. This proxy statement explains the agenda, voting information and procedures and provides information to assist you in voting your shares. It and the enclosed proxy card are being mailed to shareholders beginning on or about March 21, 2007.

Throughout this proxy statement, the terms "we," "us," "our," "the company" and "TECO Energy" refer to TECO Energy, Inc.

Voting Information

Who can vote Only shareholders of record of TECO Energy common stock at the close of business on February 23, 2007 are entitled to vote at the meeting. As of that date we had outstanding 209,588,944 shares of common stock, the only class of stock 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.

Quorum 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.

How to vote You may attend the meeting and vote in person, or you may vote by proxy by internet, telephone or mail. Please see your proxy card for more detailed voting instructions, or refer to the information your bank, broker or other holder of record provided to you. Please see "Attending in Person" below for information about attending the meeting. Even if you plan to attend, we request that you vote by proxy promptly. If you attend the meeting and wish to vote in person, your proxy will not be used.

How to revoke your proxy You may revoke your proxy at any time before it is exercised at the meeting by filing with our Corporate Secretary a written notice of revocation, submitting a proxy bearing a later date or attending the meeting and voting instructions in person.

How your votes are counted 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 our independent auditor. If other matters are properly presented at the meeting for consideration, the persons appointed as proxies on your proxy card will have the discretion to vote on these matters for you. The affirmative vote of a majority of the common stock represented at the meeting in person or by proxy will be required to elect each director and to ratify the selection of our independent auditor. 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 our guests may attend the meeting, and personal photo identification will be required to enter the meeting. On page 25, we have provided directions to the meeting, which will be held at The University of Tampa, Vaughn Center, 401 W. Kennedy Blvd., Tampa, Florida. 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 23, 2007, 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; such persons may also be asked to sign an affidavit attesting to their ownership.

Proposals Requiring Your Vote

Item 1 - Election of Directors

Our bylaws provide for the Board of Directors to be divided into three classes, with each class to hold office for a term of three years and until successors are elected and qualified at the annual meetings of shareholders. The bylaws provide that each class should be kept as nearly equal in number as possible. Messrs. Lacher, Rankin, Rockford and Touchton have been nominated for reelection to the class with a term expiring in 2010. 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 Board of Directors recommends a vote FOR each of these nominees to hold office for the term indicated above and until their successors are elected and qualified.

The Board of Directors

The following table contains information about the nominees and directors whose terms continue after the meeting. All of our directors also serve as directors of our wholly owned subsidiary, Tampa Electric Company. Information on the share ownership of each director is included under "Share Ownership" on page 7.

Nominees for election as directors at this meeting are marked with an asterisk (*).

Name	*Age*	*Principal Occupation During Last Five Years and Other Directorships Held*	*Director Since*	*Present Term Expires*
DuBose Ausley	69	Attorney and former Chairman, Ausley & McMullen, P.A. (attorneys), Tallahassee, Florida; also a director and former chairman of Capital City Bank Group, Inc.; a director of Huron Consulting Group, Inc. and Blue Cross Blue Shield of Florida, Inc.	1992	2008
James L. Ferman, Jr.	63	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	2008
Luis Guinot, Jr.	71	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	2009
Sherrill W. Hudson	64	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	2009
*Joseph P. Lacher	61	Retired; formerly President of Florida operations for BellSouth Telecommunications, Inc., (telecommunications services) Miami, Florida; also formerly Chairman, Great Florida Bank (banking services), Miami, Florida; also a director of Perry Ellis International, Inc.	2006	2007
Loretta A. Penn	57	Vice President and Chief Service Excellence Officer, Spherion Corporation (staffing and professional services), McLean, Virginia	2005	2009
*Tom L. Rankin	66	Independent Investment Manager, Tampa, Florida; 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	61	Retired; formerly President, CFO and COO, Primary Energy Ventures LLC (power generation), Oak Brook, Illinois; also formerly Managing Director, Chase Securities Inc. (financial services), New York, New York	2000	2007
William P. Sovey	73	Retired; formerly Chairman of the Board and Chief Executive Officer, Newell Rubbermaid Inc. (consumer products), Freeport, Illinois; also a director of Actuant Corporation	1996	2008
*J. Thomas Touchton	68	President, The Witt-Touchton Company LLC (private investments), Tampa, Florida	1987	2007
Paul L. Whiting	63	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	2008

Information about the Board and its Committees

Board Meetings and Attendance

The Board of Directors held five meetings in 2006. All directors attended at least 75 percent of the meetings of the Board and committees on which they served. Our policy is for directors to attend our Annual Meeting of Shareholders; in 2006, all of the directors attended that meeting. In 2006, 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.

Committees of the Board

The Board has standing Audit, Compensation, Finance, and Governance and Nominating Committees. 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 current membership of each Committee and other descriptive information is summarized below.

Director	*Audit Committee*	*Compensation Committee*	*Finance Committee*	*Governance and Nominating Committee*
DuBose Ausley	—	—	X	—
Sara L. Baldwin (1)	—	X	—	X
James L. Ferman, Jr.	X	—	—	Chair
Luis Guinot, Jr.	—	X	—	X
Sherrill W. Hudson	—	—	X	—
Joseph P. Lacher	X	—	—	—
Loretta A. Penn	—	X	—	—
Tom L. Rankin	X	—	Chair	—
William D. Rockford	—	—	X	—
William P. Sovey	--	Chair	—	X
J. Thomas Touchton	Chair	—	—	X
Paul L. Whiting	X	X	—	—

(1) Ms. Baldwin is retiring from the Board effective as of the date of the annual meeting.

The **Audit Committee** met eight times in 2006; its members are Messrs. Ferman, Lacher, Rankin, Touchton (Chair) and Whiting. The Board of Directors has determined that Messrs. Lacher, Rankin and Whiting are audit committee financial experts as that term has been defined by the Securities and Exchange Commission, and that all of the members are independent as defined by the listing standards of the New York Stock Exchange. Additional information about the Audit Committee is included in the Audit Committee Report on page 23.

The **Compensation Committee**, which met six times in 2006, is composed of Sara L. Baldwin (who does not appear in the Board of Directors table on the previous page as she is retiring from the Board effective as of the date of the annual meeting), Ms. Penn, and Messrs. Guinot, Sovey (Chair) and Whiting, all of whom are independent directors. Its primary responsibilities are to:

- review and approve the goals and objectives relevant to CEO compensation;
- evaluate the CEO's performance in light of those goals and objectives;
- determine and approve the CEO's compensation level based on this evaluation;
- make recommendations to the Board with respect to the compensation of other executive officers, incentive compensation plans and equity-based plans;
- review and discuss the Compensation Discussion and Analysis with management;
- administer and make awards under the company's long-term incentive plan; and
- make recommendations on proposed executive employment, severance and change-in-control agreements.

Management's role in the Committee's processes has been to provide the Committee with information and its ideas and input regarding compensation decisions and to discuss this information and the recommendations of the compensation consultants retained by the Committee (identified below) in detail with the Committee and answer questions. To carry out this role, management may interface directly with the Committee's outside consultant, with the Chairman of the Committee's knowledge and approval. The Committee may form and delegate authority to subcommittees and it has delegated authority to management to make small equity incentive grants to non-executive officers and key employees and to allow options to be exercised for their full term following the termination of employment by certain employees. Management reports to the Committee in detail when it exercises this authority that the Committee has delegated.

The Compensation Committee has exclusive authority to retain and terminate any compensation consulting firm to assist in the evaluation of director or senior officer compensation and to approve the consulting firm's fees and other retention terms. It has engaged Towers Perrin to help the Committee identify market trends in executive compensation, provide market data to help the Committee determine appropriate compensation levels and components, and aid the Committee in its overall assessment of the executive compensation program, taking that data and information into account. The Committee also engaged Watson & Wyatt Worldwide in 2006 to provide the Committee with a second opinion with respect to the compensation program and the Committee's practices, specifically by evaluating whether program is meeting its objectives, whether the market data being used is the most meaningful for our company and executive officers and providing suggestions on aspects of the program that it believes the Committee may wish to reevaluate. Representatives of Towers Perrin attend the Committee's meetings at the invitation of the Chairman of the Committee and are also in contact directly with him from time to time. Representatives from Watson & Wyatt met with the Committee to report on the matters discussed above and to answer the Committee's questions.

The **Finance Committee**, which assists the Board in formulating our financial policies and evaluating our significant investments and other financial commitments, met five times in 2006; 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 twice in 2006, and its members are Ms. Baldwin and Messrs. Ferman (Chair), Guinot, 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 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 it has sole authority to retain a search firm to identify potential director candidates and assist in their evaluation. Mr. Lacher, who was appointed to the Board in July 2006, was recommended to the Governance and Nominating Committee for consideration by a non-management director and the CEO. 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, TECO Energy, Inc., P.O. Box 111, Tampa, Florida 33601.

Committee Charters and Other Corporate Governance Documents

The Charters of each Committee, the Corporate Governance Guidelines, the Code of Ethics applicable to all directors, officers and employees, and the *Standards of Integrity* are available on the Corporate Governance section of the Investors page of our website, www.tecoenergy.com, and will be sent to any shareholder who requests them from the Director of Investor Relations, TECO Energy, Inc., P.O. Box 111, Tampa, Florida 33601.

Director Independence

The Board has 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 our Corporate Governance Guidelines. The Board annually reviews all business and charitable relationships of directors in order to make a determination as to the independence of each director. Only those directors who the Board affirmatively determines have no relationship with us that would impair their independent judgment will be considered independent directors. After performing such a review, the Board determined that (i) Ms. Baldwin and Messrs. Guinot, Lacher, Rankin, Rockford, Sovey, Welch (who retired from the Board in April 2006) and Whiting have no relationships with us and (ii) Mr. Ferman, Ms. Penn and Mr. Touchton only have relationships with us of the type that the Board has determined to be categorically immaterial (as defined below), and therefore were not considered by the Board as relationships that would affect their independence. The relationships with Mr. Ferman and Ms. Penn fall under category 1, as described below, and the relationship with Mr. Touchton falls under category 4, as described below.

Our Corporate Governance Guidelines adopted by the Board, define the following types of relationships as being categorically immaterial:

1. 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 us and the annual sales to, or purchases from, us 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;
2. If a director is an executive officer of another company which is indebted to us, or to which we are 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;
3. If a director is an executive officer of a charitable organization, and our discretionary charitable contributions to the organization are less than $1 million or one percent of that organization's total annual charitable receipts; and
4. If a director serves as a director or trustee of a charitable organization, and our 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 our contributions for the purpose of this item and item 3 above.)

Items 3 and 4 above recognize the Board's view that its members should not avoid volunteering as directors or trustees of charitable organizations and that we should not cease ordinary course contributions to organizations for which a director has volunteered.

In addition to defining categorically immaterial relationships, the Board has also adopted the following guidelines to assist it in making the determination of whether a relationship with a board member is material or immaterial:

1. A director shall not be independent if, within the preceding three years: (i) the director was employed by us; (ii) an immediate family member of the director was employed by us as an executive officer; (iii) the director or an immediate family member of the director received more than $100,000 in direct compensation from us, other than director fees, pension, or other deferred compensation for prior service in any 12-month period; or (iv) one of our executive officers 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 our 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 our 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 our audit within the last three years.

For relationships the character of which are not included in the categories in paragraphs 1 or 2 above or do not meet the categorically immaterial standards described 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 these independence guidelines.

Communications with the Board

The Board provides a process by which shareholders and interested parties may communicate with its members, which is described on the Corporate Governance section of the Investors page of our website, www.tecoenergy.com. Any shareholder or interested party wishing to contact our Board, or any of the non-management directors separately, may do so by mail at P.O. Box 1648, Tampa, Florida 33601, or by e-mail through the Corporate Governance section of the Investors page of our website.

Compensation of Directors

In 2006, non-management directors were paid the following compensation:

- an annual retainer of $30,000;
- attendance fees of $750 for each TECO Energy Board meeting;
- attendance fees of $750 for each Tampa Electric Company Board meeting;
- $1,500 for each meeting of a committee of the Board on which they serve;
- an additional annual retainer of $7,500 for the Chair of the Audit Committee, and an additional annual retainer of $5,000 for each other Committee Chair; and
- an annual grant of 2,500 shares of restricted stock that vests in three equal annual installments, which is prorated for directors who join after the annual grant date.

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 our common stock.

A share ownership guideline was instituted in 2006 requiring non-management directors to own, within five years of their election or the adoption of the guideline, an amount of common stock with a value of five times their annual retainer.

We pay for or reimburse directors for their meeting-related expenses or expenses associated with their duties as our directors, such as attending educational conferences. Occasionally expenses include those associated with travel on our own or other private aircraft for Board-related events.

The purpose of the components and amounts of director compensation is to allow us to continue to attract and retain qualified Board members, tie a portion of their compensation to our long-term success and recognize the significant time commitment required of our directors. The amounts described above reflect modifications to our director compensation program adopted in January 2006, which increased the annual retainer by $3,000, the Committee meeting fees by $500 and the annual retainer for the Chair of the Audit Committee by $2,500 and eliminated initial and annual stock option grants in favor of an annual restricted stock grant. Prior to making these changes, we had not adjusted director compensation in over five years. Before making recommendations to the Board regarding the director compensation program, the Compensation Committee reviewed information provided by its consultant which compared the total compensation provided to our directors to total director compensation provided by the same peer group companies used for executive compensation market surveys described in the Compensation Discussion and Analysis on page 9 of this proxy statement. These peer companies were selected as being representative of companies that we compete with for qualified Board members, reflect the mix of our utility and non-utility businesses and to some extent reflect the size of our company. However, unlike the executive compensation surveys provided by the Committee's consultant, regression analysis was not used to adjust the data to reflect our revenue scope because the many different elements that make up director compensation and its relative insensitivity to company size as compared to executive compensation would make that analysis less meaningful. The level of pay for our new director compensation program is below the median compensation paid by the companies in this peer group, which level was based on our objective of continuing to provide competitive compensation but to also have the flexibility to implement compensation changes over time depending on factors such as continuing improvements in our performance, the success of our corporate strategy and any future needs to recruit new directors.

The following table gives information regarding the compensation we provided to the non-management directors in 2006:

Director Compensation for the 2006 Fiscal Year

Name	*Fees Earned or Paid in Cash ($)* (1)	*Stock Awards ($)* (2)	*Option Awards ($)* (3)	*Total ($)*
Dubose Ausley	45,750	18,671	0	64,421
Sara L. Baldwin	50,250	18,671	0	68,921
James L. Ferman, Jr.	56,750	18,671	0	75,421
Luis Guinot, Jr.	50,250	18,671	0	68,921
Joseph P. Lacher (4)	24,000	5,356	0	29,356
Loretta A. Penn	43,500	18,671	0	62,171
Tom L. Rankin	61,250	18,671	0	79,921
William D. Rockford	43,500	18,671	0	62,171
William P. Sovey	54,500	18,671	0	73,171
J. Thomas Touchton	60,750	18,671	0	79,421
James O. Welch, Jr. (5)	16,750	0	0	16,750
Paul L. Whiting (6)	56,250	18,671	0	74,921

(1) Includes amounts that are payable in cash but that some directors may elect to either receive in the form of stock or defer into a phantom stock or cash account pursuant to our directors' deferred compensation plan.

(2) On April 25, 2006, each director who was continuing service after that date received 2,500 shares of restricted stock, which vests in three equal annual installments. Mr. Lacher, who was elected to the Board in July 2006, received a prorated grant of 1,875 shares of restricted stock. This column shows the dollar amount of these awards recognized for financial statement reporting purposes with respect to 2006 in accordance with FAS 123R. The grant date fair value of the restricted stock awards computed in accordance with FAS 123R for the grants of 2,500 shares was $40,738, and for Mr. Lacher's grant of 1,875 shares was $30,713. See Note 9, Common Stock, included in our Annual Report on Form 10-K for the year ended December 31, 2006 for a discussion of the assumptions made in these valuations. As of December 31, 2006, each director had 2,500 shares of restricted stock outstanding, except for Mr. Lacher, who had 1,875 shares of restricted stock outstanding, and Mr. Welch who retired from the Board during 2006 and had no shares of restricted stock outstanding. Dividends are paid on restricted stock awards at the same rate paid to all shareholders.

(3) As of December 31, 2006, Ms. Baldwin and Messrs. Ausley, Ferman, Sovey, Touchton and Welch each had option awards outstanding as to 20,500 shares. The remaining directors had option awards outstanding as of December 31, 2006

as follows: Mr. Guinot: 24,500 shares; Mr. Lacher: 0 shares; Ms. Penn: 10,000 shares; Mr. Rankin 28,500 shares; Mr. Rockford: 19,500 shares; Mr. Whiting: 0 shares.

(4) Mr. Lacher was elected to the Board in July 2006. Fees earned in cash include fees in the amount of $6,365 paid in the form of 369 shares of common stock at Mr. Lacher's election.

(5) Mr. Welch retired from the Board in April 2006.

(6) Fees earned in cash were paid in the form of 3,514 shares of common stock at Mr. Whiting's election.

Certain Relationships and Related Person Transactions

Our Board has adopted a written policy regarding the review, approval or ratification of related person transactions. A related person transaction for the purposes of the policy is a transaction between the company and one of our directors, executive officers or 5% shareholders, or a member of one of these person's immediate family, in which such person has a direct or indirect material interest and involves more than $120,000. Under this policy, related person transactions are prohibited unless the Audit Committee has determined in advance that the transaction is fair and reasonable to the company. In the event we enter into such a transaction without Audit Committee approval, the Audit Committee must promptly review its terms and may ratify the transaction if it determines it is fair and reasonable to the company and any failure to comply with the pre-approval policy was not due to fraud or deceit.

TECO Energy paid legal fees of $1,165,799 for 2006 to Ausley & McMullen, P.A., of which Mr. Ausley is an employee. The Audit Committee approved this transaction pursuant to the policy.

Share Ownership

Directors and Executive Officers: The following table gives information regarding the shares of common stock beneficially owned as of January 31, 2007 by our directors and nominees, executive officers named in the Summary Compensation Table below and 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 our common stock beneficially owned by any director or executive officer did not exceed 1% of the total shares outstanding at January 31, 2007; the percentage beneficially owned by all directors and executive officers as a group as of that date was 1.7%.

Name	*Shares* [1]	*Name*	*Shares* [1]
DuBose Ausley	61,344	William P. Sovey	38,582
Sara L. Baldwin	52,601 [2]	J. Thomas Touchton	73,289
James L. Ferman, Jr.	73,223 [3]	Paul L. Whiting	56,965 [7]
Luis Guinot, Jr.	30,825	John B. Ramil	459,029 [8][9]
Sherrill W. Hudson	451,489 [4]	Gordon L. Gillette	288,064 [8]
Joseph P. Lacher	11,809 [5]	Charles R. Black	120,631 [8]
Loretta A. Penn	12,500	William N. Cantrell	379,456 [8][10]
Tom L. Rankin	760,928 [6]	All directors and executive officers as a group (20 persons)	3,489,876 [8][11]
William D. Rockford	33,113		

(1) The amounts listed include the following shares that are subject to options granted under our stock option plans that are exercisable within 60 days of January 31, 2007: Ms. Baldwin and Messrs. Ausley, Ferman, Sovey and Touchton, 20,500 shares each; Mr. Guinot, 24,500 shares; Mr. Hudson, 151,686 shares; Ms. Penn, 10,000 shares, Mr. Rankin, 28,500 shares; Mr. Rockford, 19,500 shares; Mr. Whiting, 0 shares; Mr. Ramil, 298,709 shares; Mr. Gillette, 170,115 shares; Mr. Black 57,815 shares; Mr. Cantrell, 228,524 shares; and all directors and executive officers as a group, 1,441,844 shares.

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

(3) Includes 42,929 shares owned jointly by Mr. Ferman and his wife. Also includes 2,274 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 and 41,014 shares held in a margin account.

(5) Includes 9,565 shares owned by Mr. Lacher's wife, as to which shares he disclaims any beneficial interest.

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

(7) Includes 25,000 shares owned jointly by Mr. Whiting and other family members.

(8) Includes the following shares held by our benefit plans for an officer's account: Mr. Ramil, 7,305 shares; Mr. Gillette, 9,509 shares; Mr. Cantrell, 13,298 shares; Mr. Black 11,441 shares; and all directors and executive officers as a group, 61,940 shares.

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

(10) Includes 28,499 shares owned by Mr. Cantrell's wife, as to which shares he disclaims any beneficial interest.

(11) Includes a total of 75,550 shares owned jointly. Also includes a total of 41,681 shares owned by spouses, as to which beneficial interest is disclaimed, and 41,014 shares held in a margin account.

Five Percent Shareholders: The following table gives information with respect to all persons who are known to us to be the beneficial owner of more than five percent of our outstanding common stock as of December 31, 2006.

Name and Address	*Shares*	*Percent of Class*
Franklin Resources, Inc. ("Franklin") Charles B. Johnson Rupert H. Johnson, Jr. One Franklin Parkway, San Mateo, CA 94430	16,409,560 (1)	7.8%
T. Rowe Price Associates, Inc. ("Price") 100 E. Pratt Street Baltimore, MD 21202	11,875,581 (2)	5.6%

(1) Based on a Schedule 13G filed with the Securities and Exchange Commission on February 6, 2007, which reported that Franklin (and Charles B. Johnson and Rupert H. Johnson, Jr. 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 TECO Energy 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 our 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.

(2) Based on a Schedule 13G filed with the Securities and Exchange Commission on February 14, 2007, which reported that Price had sole investment power over these shares and sole voting power over 1,987,577 of these shares.

Section 16(a) Beneficial Ownership Reporting Compliance

Our 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 of our securities with the Securities and Exchange Commission. Copies of those reports must also be furnished to us.

Based solely on a review of the copies of reports furnished to us with respect to 2006 and written representations that no other reports were required, we believe that our executive officers and directors have complied in a timely manner with all applicable Section 16(a) filing requirements, except for a gift of shares made by William Cantrell that was inadvertently reported late.

Compensation Discussion and Analysis

Overview

The objectives of our executive compensation program are to enhance shareholder value by attracting and retaining the talent needed to manage and build our businesses and to link the interests of our executives to the long-term interests of our shareholders. To achieve these objectives, we seek to provide compensation that is competitive, to pay incentives based on achievement of corporate and individual performance goals (and to not pay incentives if results do not meet a minimum goal), and to tie a meaningful percentage of executive compensation to equity-based compensation, which serves to align management's interests with our shareholders'. As discussed in greater detail below, our Compensation Committee reviews relevant market data provided by its consultant and generally targets paying our executives at the 50th percentile, both in terms of the total compensation package and for each element of compensation we provide. Individual responsibilities and performance are considered in making compensation decisions, as well as different measures of company performance. This Compensation Discussion and Analysis will explain how we use different elements of compensation to achieve different aspects of these goals of the program and how we determine the amounts of each component to pay. The Compensation Committee makes recommendations to the Board regarding executive compensation matters and the Board approves the decisions; therefore, in all cases where we refer to Board approval, such approval is upon the recommendation of the Compensation Committee. For CEO compensation, the Committee discusses the matter with the Board and then approves the decisions.

Elements of Compensation

Our executive compensation program includes direct compensation components consisting of base salary, annual incentive awards and equity-based incentive awards, which are currently granted in the form of performance-based restricted stock, time-vested restricted stock and stock options. Other elements of compensation for our executive officers include the ability to participate in our tax qualified defined benefit pension plan that is available to all employees, as well as to participate in a supplemental retirement plan, which serves as an additional means to attract and retain our executive officers. Our CEO, who has pension benefits from his previous employer, does not participate in this supplemental plan. Each element of compensation, why we choose to pay each element and how the amounts are determined for each element, are discussed in greater detail below.

Base Salary

Why we pay base salary: Base salary is designed to provide each executive with a fixed amount of annual compensation that is competitive with the marketplace. We believe this is important to allow us to continue to attract and retain highly qualified executives. Having a certain level of fixed compensation also provides stability, which allows our executives to stay focused on business issues. Our CEO receives approximately two-thirds of his base salary in the form of restricted stock, which serves to further tie his compensation to our financial performance and its resulting impact on shareholder return.

How amounts of base salary are determined: The Board assigns each executive officer to a salary grade based on (i) the officer's experience level, (ii) the officer's duties and scope of responsibility, and (iii) a market assessment of the median compensation paid to executives with similar positions. This market assessment is done by the Committee's consultant, who, at least every other year, compiles data regarding compensation paid by companies in the Southeast electric utility industry, the S&P Electric Utility Index, and 125 S&P 500 companies with revenues in a range of approximately one-half to two times our revenues for the year prior to the study. The consultant uses regression analysis to scale the compensation amounts from all three sources to reflect our revenue scope. For TECO Energy officers, this data is weighted 70% for energy services companies and 30% for general industry, to reflect the mix of our utility and non-utility businesses. We evaluate this weighting of energy services and general industry data annually to ensure that it is reflective of the actual mix of our businesses and make changes to the weightings as needed. For our utility company executive officers, only energy services data is used for comparison. In interim years, the consultant provides data which shows salary movement at these groups of companies. The Compensation Committee uses the data provided to recommend a salary range for each grade, with the midpoint of each range being at the 50th percentile of the salaries of the companies used in the survey (scaled and weighted as described above). Each year the Committee recommends adjustments to the salary ranges based on surveys by its outside consultant of expected changes in compensation levels at this same mix of energy services and general industrial companies. The Committee believes this data is a useful tool to ensure that our salaries remain competitive. The Committee also believes that having ranges and considering other variables, such as individual circumstances, allows it to tailor salaries to reflect individual officer's responsibilities and experience levels. In 2006, the Board increased salary ranges for all officer grades by 2.5%. This increase was based on a study of market data showing that the national average for salary structure movement was at 2.5% for the energy services industry and 2.6% for general industry.

After setting the salary ranges for each grade, the Committee then adjusts the base salary for the CEO and recommends adjustments to the base salaries for the other executive officers. In assessing base salary adjustments for the executive officers, the Committee takes into account the midpoint of the officer's assigned salary grade, the Committee's evaluation of each executive officer's individual performance and responsibilities, and job market data. Based on these factors, in 2006 the Committee, after consultation with the Board, increased the CEO's salary by 7.4% and recommended increases for the other named executive officers from 3.5% to 7.0%. The Committee believes these were appropriate salary adjustments given each officer's performance and responsibilities and the other mix of compensation being provided. All of our named executive officers' salaries for 2006 were within 10% of the midpoint of their respective salary grade ranges.

Annual Incentive Awards

Below is information regarding our annual incentive award program, which is normally a cash award we make based on achievement of annual performance measures (although in the past we have paid a portion of the annual incentive awards in the form of stock). The discussion below first describes our policies and procedures with respect to these awards and then gives specific information with respect to the application of the policies and procedures to the 2006 awards.

Why we pay annual incentives: Our annual incentive program provides for incentive awards based on the achievement of corporate and individual performance goals. The annual incentive awards are designed to reward current performance by basing payment on the achievement of both quantifiable performance measures that reflect contribution to our business and on the achievement of quantitative and qualitative individual goals tailored to each officer's responsibilities. The annual incentive program is intended to encourage actions by the executives that contribute to our operating and financial results and to achieve other goals that the Board has recognized as important for the success of our businesses.

How annual incentive opportunities are determined: As described in greater detail below, for TECO Energy officers, 85% of each annual incentive award is based on a mix of quantitative and qualitative performance goals and 15% is based on our financial performance relative to peer companies (for operating company presidents, the respective percentages are 90% and 10%). The annual incentive goals overall are weighted 60% for achievement of quantitative financial performance goals and 40% for achievement of quantitative and qualitative individual goals. The amount of the annual incentive awards are based on a target award percentage and the level of achievement of several different goals which the Board approves for each executive officer during the first part of the year, as described in the next paragraphs.

Target Award Percentage: At the beginning of the year, the Compensation Committee sets a target award percentage tied to salary for the CEO and recommends a target award percentage for each of the other officers that they will receive if the performance goals are met. Target award levels are established at a level that, when combined with each officer's base salary, will provide a fully competitive total cash compensation opportunity, with the portion of compensation "at risk" (i.e., the target award level) being reflective of the level of that officer's accountability for contributing to bottom-line results and the degree of influence that officer has over results and competitive practice. In setting these percentages, the Committee considers these factors as well as data from the market assessment provided by its consultant and referred to above under base salary. In 2006, the target award percentages were set at 70% for the Chief Executive Officer, between 40% and 60% for each of the other named executive officers and lower amounts for other officers. In prior years, including 2006, to determine the total annual incentive opportunity for the officer, the target award percentage was multiplied by the greater of (i) the midpoint of the officer's salary range or (ii) the officer's salary. Beginning with the 2007 incentive awards, the target award percentage will be multiplied by the officer's base salary.

Performance Goals: The Board approves goals for each executive officer and the proportion of the total incentive award each goal represents. The goals are a mix of quantitative financial goals, such as earnings from continuing operations before charges and gains (which is referred to throughout this Compensation Discussion and Analysis as our "income goal" and is calculated on the same basis as the results we refer to in communications with investors as our "non-GAAP results") and cash generation, and quantitative and qualitative performance goals specific to each officer's duties, such as management of specific business issues to a positive outcome, ensuring completion of identified action items and meeting safety record goals. In 2006, 10% of each named executive officer's annual incentive was based on a "business challenge" goal which reflects the officer's contribution to mitigating the impact of unexpected adverse business or regulatory developments on the business or enhancing profitability through effective management initiatives beyond those included in the business plan. The specific weighting of the goals that comprised the annual incentive award goals for 2006 are set forth on page 17 under "Description of the formula applied in determining the amounts payable under the Annual Incentive Plan."

The Board sets threshold, target and maximum goals for the quantitative financial goals. Threshold performance represents the minimum performance that still warrants incentive recognition for that particular goal (paid at 50 percent of the target award level), and maximum performance represents the highest level likely to be attained (paid at 150 percent of the target award level for all goals, except the business challenge goal which can be paid at 200 percent). These threshold, target and maximum goals are set for the financial performance goals at the TECO Energy level and for each operating company. For example, Mr. Black's and Mr. Cantrell's financial performance goals are based on the goals set for Tampa Electric and Peoples Gas, respectively. The target goal is set at achieving the business plan target at the TECO Energy level and at each operating company, and the minimum and maximum goals are set at different percentages of achievement of the business plan, depending on the level of unpredictability of results at each company. If TECO Energy's threshold income goal is not achieved, then no incentive awards will be paid.

The 15% portion (10% for operating company officers) of the annual incentive award that is based on performance relative to peer companies is based on earnings per share growth and return on equity relative to other companies in the energy services industry, as described in more detail in the next section. (We refer to this goal as the "relative performance goal.")

<u>How annual incentive awards are calculated</u>: After the end of the year, the following four-step process is followed to determine the amount of the actual incentive awards:

Step 1: The actual degree of achievement for each goal at the corporate, operating unit and individual level is determined. Levels of achievement can range up to 200 percent for the business challenge goal and up to 150 percent for all other goals.

Step 2: Corporate, operating unit and individual performance factors are determined by multiplying levels of goal achievement by the weightings assigned to each goal.

Step 3: The total of all performance factors is multiplied by the target award, producing the calculated award.

Step 4: The calculated award may be adjusted up or down by the Compensation Committee with respect to the executive officers, based on the participant's total performance during the plan year. The actual award, as so adjusted, may not exceed 150 percent of the target award level and must be approved by the Board. No incentive award payments will be made to any participants if our income does not exceed the threshold described in the preceding section designated for that year.

For the 10% to15% portion of the annual incentives relating to the relative performance goal, the degree of achievement of the goal is determined based on our ranking on a schedule of earnings per share and average book value for companies engaged primarily in the electric utility industry. We obtain this schedule from an independent research organization which is in the business of providing research and consulting services regarding public utility regulation and the electric utility industry. This organization uses results excluding charges and gains (i.e., "non-GAAP results") to calculate the earnings per share amounts. Return on equity is calculated by dividing the earnings per share figure by our average book value. Our goal achievement level is dependent on our ranking within this list. If our performance is below the median, there is no payout for this goal. If our performance ranks in the top quarter of those companies, the goal is paid out at 150%, and if we are above the median but below the top quarter, pay out is prorated between 10% and 150%, depending on where we rank on the list.

<u>Application of the formula to the 2006 annual incentive awards</u>: The amount each named executive officer received in 2006 under our annual incentive plan has been reported in the Summary Compensation Table in the Non-Equity Incentive Compensation column (in previous years these amounts were reported under the Bonus column of the predecessor to the Summary Compensation Table). These amounts do not include the 10% to 15% portion of the annual incentive which is based on our relative performance goal because those calculations are based on data that is not available until after the printing of this

proxy statement. The achievement of the relative performance goal will be reported on a Form 8-K when it is determined and in next year's proxy statement.

The 85% (90% for operating company officers) of the annual incentives which are based on quantitative financial goals and quantitative and qualitative individual goals were calculated and awarded in January 2007. The following paragraphs describe the calculation of these incentive awards applying the four step process outlined above.

Step 1: In 2006, the targets for the quantitative financial goals were based on achieving the business plan goals at TECO Energy and each of its major operating subsidiaries for income (which is based on net income, eliminating certain gains and charges to better reflect the ongoing operations of our businesses, and as discussed above, corresponds to the "non-GAAP results" we report to investors), and cash generation. For TECO Energy, target income was set at $283.5 million and target cash generation was set at $295.0 million, and excluded the impact of any fuel and related customer pass-through items at its utility subsidiary. The threshold goal was set at 80% achievement of those goals for TECO Energy, and either 75% or 90% achievement of the goals at each of the operating companies. The maximum goals were based on achieving 115% of those goals at TECO Energy, and either 110% or 125% achievement of the goals at each of the operating companies. Because incentive plan targets were set at levels consistent with business plan targets, only performance that met the standards of the business plans would merit 100% of the incentive payments.

At TECO Energy, non-GAAP results were $233.6 million for 2006. This calculation was made by starting with our GAAP net income figure of $246.3 million and subtracting charges and gains of $10.8 million as shown in the Non-GAAP reconciliation table included in our Annual Report on Form 10-K for the year ended December 31, 2006. Cash generation at TECO Energy was calculated to be $349.5 million, excluding the impact of fuel and related customer pass-through items at Tampa Electric Company. Income was above target at two of the operating companies and between the threshold and target amounts at the other three. Cash generation was above target levels at each of the operating subsidiaries.

Achievement of the individual quantitative and qualitative performance goals were determined based on a performance evaluation of each executive officer with respect to each specific goal which (except in the case of the CEO) is first reviewed by the CEO with respect to each other executive officer and by the COO with respect to each operating company president and then presented to the Compensation Committee for its evaluation for all executive officers, including the CEO.

Step 2 (For 2006 Only): The plan formula used to calculate the annual incentive awards is normally the four step process described above. However, when the Committee was setting the goals for 2006, it determined that it would be appropriate to add an additional step to the formula that would apply in 2006 only, in order to reflect the unique situation posed by the uncertainty of earnings from synthetic fuel production at TECO Coal Corporation. Our base earnings and cash flow forecasts that we had made at the beginning of the year had excluded the impact of any reduction in the benefits from synthetic fuel production which are subject to significant variability due to the potential impact of high oil prices. Similarly, the financial performance goals approved for the executive officers assumed no reduction in the benefits from the synthetic fuel tax credits. In order that payouts under the 2006 Plan reflected the impact of oil prices on financial results, the Board determined that payouts under the plan should be calculated by first determining each executive officer's aggregate goal achievement as if there had been no synfuel-related impact on results, and then reducing that aggregate goal achievement by the same percentage that our earnings per share were impacted by any reduction in proceeds from the sale of synthetic fuel ownership interests due to high oil prices reducing the value of the synthetic fuel tax credits. In 2006, income was approximately $53 million lower than the planned net income benefit from the sale of synthetic fuel tax credits, which translated to a 18.45% reduction on earnings per share for the year due to synfuel impacts. The results of the incentive award calculation for each named executive officer are shown below. Although our officers cannot control the fluctuations in oil prices and their resulting impacts on synfuel benefits, the Committee and the Board believed this calculation would appropriately translate the effects our shareholders might feel from the reduction of synfuel related benefits to the executive officers' incentives for the year. This step will not be necessary in calculating the incentive awards for 2007 because the company has entered into oil price hedge instruments that protect the majority of its expected synthetic fuel benefits, and incentives will be based on results including the settlement amounts of these hedge arrangements to be received in early 2008.

Step 3: The total of the performance factors calculated under Step 2 was multiplied by the target percentage that had been set at the beginning of the year for each named executive officer. The calculations for the named executive officers were:

Name	*Target Award Percentage*	*Target Award Amount**	*Award Amount Without Synfuel Reduction**	*Reduction due to Synfuel Impact*	*Final Incentive Award Amount */As Percentage of Base Salary*
Sherrill W. Hudson	70%	461,125	612,258	18.45%	499,296 / 65%
John B. Ramil	65%	279,002	358,136	18.45%	292,060 / 58%
Gordon L. Gillette	55%	199,623	253,306	18.45%	206,571 / 48%
Charles R. Black	50%	155,250	201,896	18.45%	164,646 / 48%
William N. Cantrell	40%	124,200	162,364	18.45%	132,408 / 38%

* Not including portion of incentive award attributable to the relative performance goal, the achievement of which cannot be calculated until a later date. See footnote 2 to the Summary Compensation Table.

Step 4: As discussed above, our annual incentive plan allows the Compensation Committee to adjust the amount of the award that is calculated pursuant to Steps 1 – 3 if it determines that 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. Under no circumstances could awards have been more than 50% greater than the target award amount. In 2006, the Committee made no adjustments to the award amounts calculated pursuant to the plan formula it had approved when setting the goals.

Equity Incentive Awards

The long-term incentive component of our compensation program consists of equity-based grants, which have been in the form of stock options and restricted stock.

Why we grant equity incentive awards. These grants are designed to create a mutuality of interest with shareholders by motivating the executive officers and key personnel to manage the company's business so that the shareholders' investment will grow in value over time. Our executive officers receive performance shares, stock options and time-vested restricted stock. Fifty percent of the value of our long-term incentives is in the form of performance shares, which are shares of restricted stock vesting three years after the date of grant in an amount that is based on our total return over those three years as compared to the companies listed in the Dow Jones Electricity Group and Multiutility Group. The performance shares, which are intended to directly tie an amount of compensation to a long-term performance measure relative to other companies in the industry, would be forfeited if the executive leaves during those three years and are not be paid out at all if performance is in the bottom one-third of our peers (more details on this calculation are described in the next paragraph). Thirty percent of the value of our long-term incentives is granted in the form of time-vested restricted stock, which vest three years after the date of grant. The ultimate value of these shares to the executives is dependent on our stock price, which aligns their interest in stock value appreciation with our shareholders', and the three-year vesting period aids in the retention of our executives since the shares would be forfeited upon departure from the company within the three-year period. Twenty percent of the value of our long-term incentives is granted in the form of stock options, which vest in three substantially equal annual installments beginning one year from the date of grant and only have value if our share price increases after the grant. Currently, none of our executive officers owns more than 1% of our outstanding common stock (including options) and at this level of ownership the Compensation Committee believes that granting additional equity awards still provides a valuable incentive that will further increase the tie between their performance and their compensation. In granting these awards, the Committee is 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 about this time, shares may be sold by the executive officers or withheld by TECO Energy 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 company's prospects by the executive officers.

How the amounts of equity incentive awards are determined. The Compensation Committee's policy with respect to the amount of equity incentive grants has been to base individual awards on an annual study conducted by its outside consultant comparing the value of long term incentive grants to salary levels in the energy services industry and in general industry. The competitive market for the purposes of this data is the same mix of the energy services and general industry sectors as is used for other elements of compensation and described under base salary, weighted 70 percent for energy services and 30 percent for general industry. The Committee also looks at the total number of shares subject to equity incentive awards in relation to the total of our outstanding shares. The Committee's current guideline is to keep total share based grants each year below 1% of our total outstanding shares. As discussed above, equity incentives are granted in the form of 50% performance based restricted stock, 30% time-vested restricted stock and 20% stock options. This mix is meant to tie the largest percentage of the equity incentives directly to our performance relative to companies in our industry, with the value of the remaining incentives also being tied to shareholder return and continued service.

In 2006, the Committee granted equity incentive awards at the 50th percentile of the market as shown in the data provided by its consultant. It believes granting equity incentive awards at the 50th percentile of this market data is appropriate given that one of the program's goal is to remain competitive with the marketplace. The Committee also reviewed information that showed total equity holdings for each executive officer, including vested and unvested awards and the total value of those holdings. In 2006, the Committee determined that it was still appropriate to target equity incentive awards at the 50th percentile of the market because levels of equity ownership are still at levels at which additional equity grants are meaningful incentives for our executives. The awards granted in 2006 also reflected the market data showing a decline in overall competitive long-term expected value of approximately 10% on average for general industry and 7% for the energy services industry. The Committee also reviewed information with respect to the estimated total and annual accounting expense associated with the equity incentive grants. Using this information, the Committee made equity incentive award grants at a level that it believes will enable us to continue to attract, retain and motivate our executives, control dilution and maintain reasonable annual accounting expense.

The number of the performance shares ultimately received by the executive officers is based on the total return of our common stock over a three-year period relative to that of peer companies, as further described on page 17 under "Description of the formula applied in determining the amounts payable under the Equity Incentive Plan and applicable vesting schedules." We think this design for payout best reflects the objective of granting the performance-based restricted stock by directly tying the amount received to total return relative to a group of our peers. In 2006, the performance shares granted in 2003 vested at 109.3%, since our total return over that three-year period was above the median of peer companies. For three years prior to that, the performance shares were forfeited due to our total return for the respective three-year periods being in the bottom 1/3 of the peer companies.

The time-vested restricted stock granted in 2006 vests in a single installment following three years of service. The stock options granted in 2006 vest ratably over a three-year period and have a ten-year term.

We believe these three components provide long-term incentives which reward continued service and have a value dependent on our performance.

Expensing of Equity. The amounts reported under the Stock Awards and Option Awards columns in the Summary Compensation Table below reflect the dollar amount recognized for financial statement reporting purposes with respect to the fiscal year in accordance with FAS 123R, including expense recognized in 2006 for stock and option grants made in years prior to 2006. Under FAS123R, stock and option award expense is generally spread out over the vesting period of the grant. However, in 2006, Mr. Hudson reached the age at which all of his stock and option grants are required to be expensed immediately. Therefore, the amounts shown for him in these columns represent the full grant date present value of the grants he received in 2006, plus any expense attributed to his outstanding equity grants from prior years which had not been previously expensed. This accounting treatment caused the values reported for Mr. Hudson to be higher than they would have been if the expense of his grants had been spread out over the applicable vesting periods, as they are for the other officers in the table.

Stock Option Grant Date and Exercise Price. The Compensation Committee has a long-standing practice of making annual equity-incentive award grants, including stock options, on the date of our annual shareholders' meeting. On selected occasions it has granted equity incentives upon election of a new executive officer. In all cases, the grant date is the same day that the Committee approved the grant. The exercise price of options is set at the fair market value on the date of grant, which is determined by averaging our high and low stock price on the day preceding the date of grant. This is consistent with how we calculate fair market value for other purposes, such as the fair market value of the other equity incentive awards and for tax purposes upon exercise of options, for example.

Stock Ownership Guidelines. 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 Committee reviews share ownership on an annual basis to ensure continued compliance with these guidelines and has determined that our executive officers are in compliance. For purposes of the guidelines, stock ownership includes directly held common stock, time-vested restricted stock, performance shares and indirectly held shares that are considered beneficially owned under applicable SEC rules (not including stock options). We believe that these guidelines and policies are appropriate for ensuring that our executive officers hold a sufficient amount of our equity to ensure that there is a mutuality of interest between our executive officers and our shareholders.

Other Elements

For our named executive officers, other than our CEO, the amount of compensation shown under the Other Compensation column of the Summary Compensation Table represents approximately 0.6% or less of their total compensation for the year. These amounts represented mainly company matches to our defined contribution plan, a benefit that is available to all of our employees that contribute to the savings plan. We also pay an annual premium of $372 for a $100,000 supplemental life insurance policy for each of our officers and key employees. In 2004, we hired Sherrill Hudson, who was at that time serving as one of our independent directors, to be our CEO. As a long-time resident of Miami, the Board recognized that he would retain his residence there, and therefore has provided him a housing and travel allowance of $5,000 per month. The Board also determined that, in recognition of Mr. Hudson's retaining his residence in Miami, it was appropriate that he be able to use our corporate aircraft, and in 2006 the incremental cost to the company for such use was $25,491, as shown in the All Other Compensation column of the Summary Compensation Table on page 15.

Our executive officers are also able to participate in a supplemental retirement plan which provides benefits at a level that are not available under the tax qualified plan and is meant as an additional aid in attracting and retaining officers in key positions. As discussed above, our CEO does not participate in the supplemental retirement plan.

We also have change-in-control agreements with each of our executive officers and certain other officers. These agreements are all "double-trigger" arrangements, meaning that payments are only made if there is a change-in-control of the company or one is being contemplated and the officer's employment is terminated without cause or the officer terminates employment for good reason. The agreements for all our executive officers are the same, and the definition of "change in control" is the same as in our equity grants and supplemental executive retirement plan and other benefits documents. These agreements are discussed in greater detail on pages 20-21 under "Post-Termination Benefits." We believe that providing these agreements helps increase our ability to attract, retain and motivate highly qualified management personnel and encourage their continued dedication without distraction from concerns over job security relating to a change in control of the company.

How the Elements Fit into our Overall Compensation Objectives and Affect Decisions Regarding Other Elements

As part of its evaluation process in making its compensation decisions for 2006, the Compensation Committee reviewed "proforma" information and a tally sheet for each executive officer. The proforma information showed each element of compensation for the executive officers as proposed for 2006 and the total of the elements, assuming payout of the annual incentive awards at the target level. For comparison purposes, proforma information also showed the average total compensation of similar positions in general industry, the energy services industry and combined (weighted and scaled as discussed on page 9). The Committee also reviewed internal pay equity information showing the percentage of total compensation provided to each executive officer as a percentage of the CEO's total compensation. The tally sheets prepared for the executive officers showed total compensation paid to the executive officers for 2004, 2005 and as proposed for 2006 and percentage changes year over year. The tally sheets also showed the value of each executive officer's total equity holdings, for both vested and unvested or restricted holdings. Finally, the tally sheets showed the amounts that would be payable to each executive officer in the event of voluntary termination, termination for cause, termination without cause, and termination in connection with a change in control of the company. The amounts payable upon the various termination scenarios included cash, equity, retirement benefits and excise tax gross-up, if and as applicable to each scenario, including the value of the supplemental executive retirement plan lump sum benefit and present value of the tax qualified defined benefit plan annuity, if applicable. The Committee reviews this information in order to be aware of how its decisions with respect to one element of compensation affect the total package that we are providing and how it relates to previous years, and the total amount executive officers would be receiving, including the value of equity awards, under various termination scenarios. Reviewing this information allows the Committee to make an overall assessment of the reasonableness of the total compensation that we are providing our executive officers. The Compensation Committee reviewed this information regarding the different elements of compensation and their total and determined that it was appropriate, given current levels of compensation being provided, to continue the policies discussed above for determining the amounts of the different elements to provide.

Under Section 162(m) of the Internal Revenue Code, we will not receive a federal income tax deduction for compensation to any named executive officer that exceeds $1 million, unless the compensation is "performance-based" as defined in the Code. Compensation attributable to performance-based restricted stock and stock options is not subject to the Section 162(m) limit because it is performance-based under Section 162(m). The Committee does not expect that the loss of any income tax deduction under this section will be material. Accordingly, the Committee has recommended that we continue to structure our executive compensation program to meet the objectives and in the manner described above.

Compensation Committee Report

The Compensation Committee has reviewed and discussed the Compensation Discussion & Analysis with management and, based on this review and discussion, has recommended that it be included in this proxy statement.

By the Compensation Committee,
William P. Sovey (Chairman)
Sara L. Baldwin
Luis Guinot, Jr.
Loretta A. Penn
Paul L. Whiting

The following tables give information regarding the compensation provided to our Chief Executive Officer, Chief Financial Officer and each of the three other most highly compensated executive officers in 2006.

Summary Compensation Table for the 2006 Fiscal Year

Name and Principal Position	*Year*	*Salary ($)*	*Stock Awards[1] ($)*	*Option Awards [1] ($)*	*Non-Equity Incentive Plan Compensation [2] ($)*	*Change in Pension Value and Nonqualified Deferred Compensation Earnings [3] ($)*	*All Other Compensation [4] ($)*	*Total ($)*
Sherrill W. Hudson Chairman and Chief Executive Officer	2006	775,000 [5]	2,082,029 [5]	664,969 [5]	499,296	15,605	95,180 [6]	4,132,079
John B. Ramil President and Chief Operating Officer	2006	500,000	716,637	230,010	292,060	233,751	9,091	1,981,549
Gordon L. Gillette Executive Vice President and Chief Financial Officer	2006	427,000	463,192	145,876	206,571	263,482	6,729	1,512,850
Charles R. Black President, Tampa Electric	2006	345,000	246,952	83,675	164,646	535,686	7,128	1,373,691
William N. Cantrell President, Peoples Gas System	2006	345,000	319,735	91,130	132,408	41,294	5,532	935,090

(1) The amounts reported for stock and option awards reflect the dollar amount recognized for financial statement reporting purposes with respect to the fiscal year in accordance with FAS 123R (without regard to estimated forfeitures related to service-based vesting conditions), including expense recognized in 2006 for stock and option grants made in years prior to 2006. See Note 9, Common Stock, included in our Annual Report on Form 10-K for the year ended December 31, 2006 for a discussion of the assumptions made in valuations of equity grants. Values for option awards include amounts expensed in 2006 for grants made from 2003 through 2006 and for stock awards include amounts expenses for time-vested restricted stock and performance-based restricted stock granted in 2003 through 2006 (see page 17 for a description of the vesting schedule and conditions and footnote 5 regarding Mr. Hudson's grants).

(2) A 10% or 15% percent portion of each executive officer's annual incentive award is based on our annual earnings per share growth and return on equity relative to that of other companies in the industry and is determined using comparative data that does not become available until after the time of printing of the proxy statement (the "relative performance goal"). This portion of the annual incentive award, if any, is expected to be determined on approximately May 2, 2007 and will be reported on a Form 8-K and in next year's proxy statement. The amount the named executive officers received representing achievement of the relative performance goal for 2005 was reported in our Form 8-K dated April 26, 2006.

(3) This column shows the change in the actuarial present value of the benefits that would be provided under our tax qualified defined benefit plan and our supplemental retirement plan. This value is calculated based on variables such as average earnings and years of service, and therefore a larger increase in value may be attributable, for example, to an increase in pay year over year. Other factors affecting the present value include interest rates and the age of the officer. See pages 19-20 for a description of our retirement plans. The change in value attributable to the tax qualified plan was: $15,605 for Mr. Hudson, $15,858 for Mr. Ramil, $7,548 for Mr. Gillette, $29,312 for Mr. Black and $24,621 for Mr. Cantrell, with the balance in each case representing the change in value of the supplemental plan.

(4) The amounts reported in this column include $372 in premiums paid by us to the Executive Supplemental Life Insurance Plan and $3,960 of employer contributions under the TECO Energy Group Retirement Savings Plan.

(5) Mr. Hudson received $250,000 of his salary in the form of cash and $525,000 in the form of restricted stock, which vested in four equal quarterly installments over the year. These shares are also reflected in the All Other Stock Awards column of the Grants of Plan-Based Awards Table below. The grant date present value of such shares as computed in accordance with FAS 123R was $525,007. In 2006, Mr. Hudson reached the age at which the entire value of all of his outstanding stock and option grants were required to be expensed immediately, causing higher values to be reported for him under the Stock and Option Awards columns than would have been reported if the expense was spread out over the vesting period, as it is for the other officers. If Mr. Hudson's equity award values had been reported in the same manner as those of the other officers shown in the table, the amount for his stock awards would have been $956,541 and the amount for his option awards would have been $421,017.

(6) Includes $60,000 for a housing and travel allowance of $5,000 per month, in recognition of Mr. Hudson's retaining his residence in Miami; $25,491 for the incremental cost to the company for personal use of our corporate aircraft, which was determined by calculating the variable costs, such as jet fuel, variable employee costs and landing fees, on a per hour basis multiplied times the number of hours flown; club membership dues; incremental cost to the company of providing on-site parking; and the items identified in footnote 4, above.

Grants of Plan-Based Awards for the 2006 Fiscal Year

Name	*Grant Date*	*Estimated Possible Payouts Under Non-Equity Incentive Plan Awards* [1]			*Estimated Future Payouts Under Equity Incentive Plan Awards* [2]			*All Other Stock Awards: Number of Shares of Stock or Units* [4] *(#)*	*All Other Option Awards: Number of Securities Underlying Options* [5] *(#)*	*Exercise or Base Price of Option Awards ($/Sh)* [6]	*Grant Date Fair Value of Stock and Option Awards ($)*
		Thresh-old [3] *($)*	*Target ($)*	*Maxi-mum ($)*	*Thresh-old* [3] *(#)*	*Target (#)*	*Maximum (#)*				
Sherrill W. Hudson		271,250	542,500	813,750							
	1/25/06							29,932 [7]			525,007
	4/26/06				28,150	56,300	112,600				956,396
	4/26/06							33,400			544,253
	4/26/06								138,200	16.295	450,785
John B. Ramil		164,119	328,238	492,357							
	4/26/06				14,750	29,500	59,000				501,131
	4/26/06							17,500			285,163
	4/26/06								72,450	16.295	108,313
Gordon L. Gillette		117,425	234,850	352,275							
	4/26/06				8,150	16,300	32,600				276,896
	4/26/06							9,650			157,246
	4/26/06								40,000	16.295	59,800
Charles R. Black		86,250	172,500	258,750							
	4/26/06				5,600	11,200	22,400				190,260
	4/26/06							6,650			108,362
	4/26/06								27,550	16.295	41,187
William N. Cantrell		69,000	138,000	207,000							
	4/26/06				4,625	9,250	18,500				157,134
	4/26/06							5,500			89,623
	4/26/06								22,650	16.295	33,861

(1) A portion of the awards in these columns were made under our 2006 Annual Incentive Plan in January 2007. A 10-15% portion of each award is based on the relative performance goal that is not able to be determined until after the printing of this proxy statement. See footnote 2 to the Summary Compensation Table.

(2) Amounts in these columns represent performance share grants made under our 2004 Equity Incentive Plan.

(3) The threshold amounts are 50% of the target awards, which would be paid if a predetermined minimum level of performance is achieved; however, if the minimum level of performance is not achieved, then there would be no incentive payment or performance shares received, as applicable.

(4) Amounts in this column represent time-vested restricted stock grants made under our 2004 Equity Incentive Plan.

(5) Amounts in this column represent stock option grants made under our 2004 Equity Incentive Plan.

(6) The exercise price of these option awards was determined by the average of the high and low sales price of our common stock on the day preceding the date of grant, which was higher than the closing price of our common stock on the date of grant. See discussion in Compensation Discussion and Analysis on page 13.

(7) These shares were granted in lieu of a portion of Mr. Hudson's salary, and the value of such shares is included in the Salary column in the Summary Compensation Table above.

Description of the formula applied in determining the amounts payable under the Annual Incentive Plan (reported as a "Non-Equity Incentive Plan"):

The amounts payable under the annual incentive plan are determined based on the achievement of certain financial and qualitative goals described above in the Compensation Discussion and Analysis (CD&A) section above. The threshold, target and maximum amounts that could have been paid under the 2006 annual incentive plan are shown in the table above in the "Estimated Possible Payout Under Non-Equity Incentive Awards" column in compliance with the applicable disclosure rules, which require that we show these amounts under that column. The amounts paid under the plan for 2006 have already been determined as discussed in the CD&A and shown in the Summary Compensation Table (except for the portion that is attributable to the relative performance goal).

In 2006, the named executive officer annual incentive awards were based on the level of achievement of the performance goals, weighted as follows:

- TECO Energy's Income/Cash Generation Goal: 25% or 20% (lower percentage for operating company presidents)
- TECO Energy's Earnings Per Share/Return on Equity Goal Relative to Peers: 10% or 15% (lower percentage for operating company presidents)
- Operating Units' Net Income/Cash Generation Goals: 20% or 30% (higher percentage for operating company presidents)
- Individual Quantitative and Qualitative Performance Goals: 40%

After the end of the year, the achievement of the goals was calculated and the amounts payable determined according to the following formula:

- Target Award Percentage x Salary (or midpoint of salary range, whichever is greater) = Target Award Amount
- Sum of Goal Weights x Goal Achievements = Total Goal Achievement
- Target Award Amount x Total Goal Achievement = Payout Amount

As described in the CD&A, annual incentive awards for 2006 were reduced according to a calculation that the Compensation Committee approved in the first part of the year to reflect the effect the reduction of synfuel-related benefits had on our earnings per share for the year. The reduction to the payouts is shown above in the CD&A on page 11.

The actual amount that was paid for 2006 under the annual incentive plan according to the formula described above has been reported in the Non-Equity Incentive Plan Compensation column in the Summary Compensation Table, excluding any amount attributable to the 10% or 15% portion of the annual incentive award related to the relative performance goal. In April 2007, the Compensation Committee will determine what level of achievement was attained regarding the company's relative performance to peer group companies and will make any corresponding payments to the executives of the balance of the 2006 annual incentive award. Awards paid under our annual incentive plan were reported in our previous proxy statements as "bonus," but under new rules adopted by the Securities and Exchange Commission in 2006, we believe these payments are more accurately described as "non-equity incentive plan compensation" as defined in those new rules.

Description of the formula applied in determining the amounts payable under the Equity Incentive Plan, applicable vesting schedule and payment of dividends:

As described above in the CD&A, equity incentive awards were granted to the named executive officers in 2006 in the form of performance-based restricted stock, time-vested restricted stock and stock options. The stock options vest in three equal annual installments beginning one year from the date of grant, and the time-vested restricted stock vests in a single installment three years from the date of grant. The restricted stock Mr. Hudson receives as a portion of his salary vests in four quarterly installments. The payout or forfeiture of performance-based restricted stock is dependent upon the total return of our common stock over a three-year period relative to that of the median company (in terms of total return) of the companies listed in the Dow Jones Electricity Group and Multiutility Group. The threshold, target and maximum number of shares that may be paid under these awards granted in 2006 is shown in the "Estimated Future Payouts Under Equity Incentive Plan Awards" column above. If our common stock's total return is equal to that of the median company of those groups during the three-year period, the payout will be equal to 90% of the target amount. If the total return is in the top 10% of the companies, the payout will be at 200% of the target amount. If the total return is in the bottom one-third of these companies, there will be no payout. A minimum payout of 50% of the target amount will be made if we are at the 33.3 percentile. Payout is prorated for performance between the bottom one-third and top 10%.

Holders of restricted stock receive the same dividends as holders of other shares of our common stock. For the performance-based restricted stock, this means that during the three year performance period, dividends are paid on the target number of shares. At the end of the three year performance period, depending on the payout as described above, (i) the performance shares are either forfeited, in which case dividends are no longer paid on such shares, or (ii) restrictions on the shares terminate and, potentially, additional shares are granted. Because restrictions terminate at that time, the holder becomes the holder of shares of non-restricted common stock with the same terms as all shares as all of our common stock, including a right to receive dividends if and when declared.

Salary and annual incentives in proportion to total compensation

As discussed above on pages 13-14 in the CD&A, the Compensation Committee reviews information with respect to each element of compensation and how those elements relate to total compensation. One goal of the compensation program is to attract and retain the talent needed to manage and build our businesses. In 2006, elements other than salary and the annual incentive award were approximately one-half of our CEO's and COO's total direct compensation, approximately 40% of our CFO's total direct compensation and between 33% and 37% for the other named executive officers. This proportion ties a greater percentage of compensation directly to shareholder return for those officers with greater influence over operating results, while still providing an amount of fixed compensation that is competitive with the marketplace.

Outstanding Equity Awards at 2006 Fiscal Year-End

	Option Awards				*Stock Awards* [1]			
Name	*Number of Securities Underlying Unexercised Options (#) Exercisable*	*Number of Securities Underlying Unexercised Options (#) Unexercisable*	*Option Exercise Price ($)*	*Option Expiration Date*	*Number of Shares or Units of Stock That Have Not Vested (#)*	*Market Value of Shares or Units of Stock That Have Not Vested ($)*	*Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)* [2]	*Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)* [2]
Sherrill W. Hudson	10,000	—	13.6350	01/28/2013	30,850[3]	$531,546	51,450[3]	$886,484
	2,500	—	11.0850	04/20/2013	33,400[4]	$575,482	56,300[4]	$970,049
	2,500	—	13.5550	04/26/2014				
	33,334	16,666[5]	12.0050	07/05/2014				
	33,334	16,666[5]	12.6053	07/05/2014				
	33,334	16,666[5]	13.2055	07/05/2014				
	36,684	73,366[6]	16.2050	04/26/2015				
	—	138,200[7]	16.2950	04/25/2016				
John B. Ramil	16,830	—	27.5625	04/14/2008	16,897[8]	$291,135	16,897[8]	$291,135
	36,807	—	21.4063	04/20/2009	15,550[3]	$267,927	25,950[3]	$447,119
	41,377	—	21.2500	04/18/2010	17,500[4]	$301,525	29,500[4]	$508,285
	43,482	—	31.5750	04/17/2011				
	51,622	—	27.9650	04/16/2012				
	22,233	—	11.0850	04/20/2013				
	67,858	33,928[9]	13.5000	04/27/2014				
	18,500	37,000[6]	16.2050	04/26/2015				
	—	72,450[7]	16.2950	04/25/2016				
Gordon L. Gillette	10,000	—	24.3750	04/15/2007	12,069[8]	$207,949	12,069[8]	$207,949
	28,447	—	21.2500	04/18/2010	11,000[3]	$189,530	18,350[3]	$316,171
	25,200	—	31.5750	04/17/2011	9,650[4]	$166,270	16,300[4]	$280,849
	28,188	—	27.9650	04/16/2012				
	16,710	—	11.0850	04/20/2013				
	48,470	24,235[9]	13.5000	04/27/2014				
	13,100	26,200[6]	16.2050	04/26/2015				
	—	40,000[7]	16.2950	04/25/2016				
Charles R. Black	8,000	—	24.3750	04/15/2007	3,908[8]	$67,335	3,908[8]	$67,335
	4,200	—	27.5625	04/14/2008	6,550[3]	$112,857	10,900[3]	$187,807
	4,612	—	21.4063	04/20/2009	6,650[4]	$114,580	11,200[4]	$192,976
	2,689	—	21.2500	04/18/2010				
	10,061	—	31.5750	04/17/2011				
	10,528	—	27.9650	04/16/2012				
	2,078	—	11.0850	04/20/2013				
	7,847	7,847[9]	13.5000	04/27/2014				

Table continues on next page.

	Option Awards				*Stock Awards* [1]			
Name	*Number of Securities Underlying Unexercised Options (#) Exercisable*	*Number of Securities Underlying Unexercised Options (#) Unexercisable*	*Option Exercise Price ($)*	*Option Expiration Date*	*Number of Shares or Units of Stock That Have Not Vested (#)*	*Market Value of Shares or Units of Stock That Have Not Vested ($)*	*Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)* [2]	*Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)* [2]
	7,800	15,600[6]	16.2050	04/26/2015				
	—	27,550[7]	16.2950	04/25/2016				
William N. Cantrell	16,830	—	27.5625	04/14/2008	10,230[8]	$176,263	10,230[8]	$176,263
	33,485	—	21.4063	04/20/2009	6,000[3]	$103,380	10,000[3]	$172,300
	28,447	—	21.2500	04/18/2010	5,500[4]	$94,765	9,250[4]	$159,378
	36,070	—	31.5750	04/17/2011				
	41,094	—	27.9650	04/16/2012				
	24,364	—	11.0850	04/20/2013				
	41,084	20,542[9]	13.5000	04/27/2014				
	7,150	14,300[6]	16.2050	04/26/2015				
	—	22,650[7]	16.2950	04/25/2016				

(1) Time-vested restricted stock that has not vested is reported under the first and second columns under "Stock awards," and performance shares for which the performance period has not run is reported under the third and fourth columns under "Stock Awards."

(2) Shares shown under this column are performance shares that vest three years following the date of grant on the dates shown in the following footnotes, subject to satisfaction of performance criteria.

(3) Vest in one installment on April 27, 2008, three years from the date of grant; the performance shares shown under "Equity Incentive Plan Awards" vest on March 31, 2008, depending on the satisfaction of performance criteria.

(4) Vest in one installment on April 26, 2009, three years from the date of grant; the performance shares shown under "Equity Incentive Plan Awards" vest on March 31, 2009, depending on the satisfaction of performance criteria.

(5) Exercisable on July 6, 2007 (the last of three substantially equal annual installments).

(6) Exercisable in two substantially equal annual installments beginning April 27, 2007 (the second and third of three substantially equal annual installments).

(7) Exercisable in three substantially equal annual installments beginning April 26, 2007.

(8) Vest in one installment April 28, 2007, three years from the date of grant; the performance shares shown under "Equity Incentive Plan Awards" vest on March 31, 2007, depending on the satisfaction of performance criteria.

(9) Exercisable on April 28, 2007 (the last of three substantially equal annual installments).

Option Exercises and Stock Vested in Last Fiscal Year

	Option Awards		*Stock Awards*	
Name	*Number of Shares Acquired on Exercise (#)*	*Value Realized on Exercise ($)*	*Number of Shares Acquired on Vesting* [1] *(#)*	*Value Realized on Vesting* [1] *($)*
Sherrill W. Hudson	0	0	29,932	478,575
John B. Ramil	0	0	46,837	766,308
Gordon L. Gillette	0	0	22,757	372,331
Charles R. Black	0	0	8,604	140,772
William N. Cantrell	0	0	32,029	524,032

(1) The shares Mr. Hudson acquired on vesting were shares of restricted stock granted in lieu of salary; the shares acquired on vesting for the other named executive officers were a combination of time-vested restricted stock and performance shares.

Pension Benefits

The following table shows the present values of accumulated benefits payable under our pension plan arrangements for the named executive officers as of September 30, 2006, the most recent pension plan measurement date for financial reporting purposes. No pension payments were made to any of the named executive officers during 2006. The pension plan arrangements shown in the table include the TECO Energy Group Retirement Plan, our tax-qualified defined benefit plan that is available to all of our employees (the "qualified plan"), and the TECO Energy Group Supplemental Executive Retirement Plan, a supplemental executive retirement plan (the "supplemental plan"). As described in the CD&A, Mr. Hudson does not participate in our supplemental executive retirement plan. The number of years of credited service is the same for the qualified plan and supplemental plan and is rounded up or down to the nearest whole year.

Name	*Plan Name*	*Number of Years Credited Service (#)*	*Present Value of Accumulated Benefit ($)*
Sherrill W. Hudson	qualified plan	2	32,803
	supplemental plan		0
John B. Ramil	qualified plan	31	333,870
	supplemental plan		2,088,876
Gordon L. Gillette	qualified plan	25	198,018
	supplemental plan		1,181,692
Charles R. Black	qualified plan	33	490,075
	supplemental plan		1,356,914
William N. Cantrell	qualified plan	31	430,502
	supplemental plan		1,656,803

All of our employees, including executive officers, are eligible to participate in our tax-qualified defined benefit plan, and become 100% vested in the benefit they have accrued upon completion of five years of service or reaching the age of 65. All of our named executive officers are vested in this plan except for Mr. Hudson. Normal retirement age for the qualified plan is the same as the eligibility age for unreduced Social Security benefits. The qualified plan's normal retirement payment and benefit formula is based on the employee's age, years of service and final average earnings. Benefits can be paid as an annuity or in a lump sum, at the election of the participant. The present value of the accumulated benefit under the qualified plan in the table above was calculated assuming that participants retire at their earliest unreduced retirement age, using a present value discount rate of 5.85%, and a lump sum conversion rate of 5.00%.

The normal retirement payment and benefit formula for our supplemental executive retirement plan is: 3% times final average earnings times years of credited service, up to a maximum of twenty years (therefore the maximum amount payable is 60% of final average earnings). 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 earnings covered by the pension plan arrangements are the same as those reported as salary and non-equity incentive plan awards in the summary compensation table above. 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. Benefits payable under the supplemental plan are also reduced by benefits payable under the qualified pension plan. Normal retirement age is 63 for Messrs. Cantrell and Black, 63 and two months for Mr. Ramil and 64 for Mr. Gillette. A reduced amount of benefits may be received upon retirement anytime within 7 years of normal retirement age, as long as the officer has 5 years of service. If early retirement is elected, payment is based on actual years of service at early retirement using the formula described above, however, benefits are reduced by 5% for each year that payment begins before the normal retirement date.

Pursuant to the terms of the supplemental plan, if a change in control of the company occurs before the officer retires but after reaching early retirement age, the officer would be eligible to receive the same benefit that would normally be payable for early retirement, except the minimum 5 years of service requirement does not apply. Before early retirement age, a benefit would also be payable based on length of service and final average earnings on the date of the change of control, reduced by between 10% and 59% at a rate of 5% for every year payment would be before normal retirement age. Pursuant to the terms of the named executive officers' change-in-control severance agreements, if those agreements are triggered as described below, the officers would receive a cash payment equal to the additional retirement benefit which would have been earned under our retirement plans if employment had continued for three years following the date of termination.

The benefit payable under the supplemental plan is paid in the form of a lump sum only (not an annuity). The present value of the accumulated benefit for the supplemental plan shown in the table of above was calculated by discounting the lump sum that would be payable at the officer's normal retirement age using a discount rate of 5.85%.

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 in the form of a lump sum to the spouse.

Post-Termination Benefits

Change-in-Control Agreements

We have change-in-control severance agreements with the named executive officers under which payments will be made under certain circumstances in connection with a change in control of TECO Energy. A change in control means in general an acquisition by any person of 30% or more of our common stock, a change in a majority of our directors, a merger or consolidation in which our shareholders do not have at least 65% of the voting power in the surviving entity, or a liquidation or sale of our assets. Each of these officers is required, subject to the terms of the agreements, to remain our employee for one year following a potential change in control unless a change in control occurs earlier. A potential change in control would occur if we entered into an agreement which would result in the occurrence of a change in control, if any person publicly announced an intention to take or consider taking actions which would constitute a change in control, the acquisition or disclosure of a plan to acquire 9.9% or more of our outstanding common stock, or if the board adopted a resolution to the effect that a potential change in control of the company has occurred. Under the terms of the change-in-control agreements, in the event employment is terminated in contemplation of or following a change in control, the officer would be entitled to receive his or her base salary through the termination date, and under the terms of the annual incentive plan, an incentive award equal to the target incentive amount for the year or the amount paid for the prior year (if greater), prorated for the number of days served in the year the termination occurred. The change-in-control agreements also provide that in the event employment is terminated by us without cause (as defined below) or by one of these officers for good reason (as defined below) in contemplation of or following a change in control, we will make a lump sum severance payment to the officer of three times annual salary and bonus (referred to as "Non-Equity Incentive Plan Compensation" in the Summary Compensation Table above). In such event, the change-in-control agreements also provide for: (a) a cash payment equal to the additional retirement benefit which would have been earned under our retirement plans if employment had continued for three years following the date of termination, (b) participation in our life, disability, accident and health insurance plans for a three-year period except to the extent these 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 change-in-control 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 supplemental executive retirement plan provides for vesting and ability to begin benefits before the usual early retirement age upon a change in control (as described above under "Pension Benefits") and the terms of stock options and restricted stock provide for acceleration of vesting upon a change in control as described below under "Accelerated Vesting of Equity Upon a Change in Control."

For the purposes of these agreements, termination with "cause" is defined as termination resulting from the willful and continued failure to substantially perform job duties or willful engagement in conduct which is demonstrably and materially injurious to the company, monetarily or otherwise. "Good Reason" for termination of employment would be the assignment to the officer of any duties inconsistent (except in the nature of a promotion) with the position held immediately prior to the change in control or a substantial adverse alteration in the nature or status, responsibilities or the conditions of employment, a reduction in annual base salary, a requirement to be based more than 25 miles from current job location, the failure by the company to pay compensation within 7 days of the due date, the discontinuation without substitution of any material compensation or benefit plan or other benefits the officer participated in immediately prior to the change in control or reduction of those benefits, or if the company attempted to terminate the officer's employment in a manner not consistent with the terms of the agreement.

Accelerated Vesting of Equity Upon a Change-in-Control

The agreements that govern all employee stock options and time-vested restricted stock awards provide that all outstanding stock options and time-vested restricted stock vest upon a change in control, as defined above. The agreements that govern the performance share awards also provide that upon a change in control, the performance period ends and the normal formula used for determining the number of shares to be received or forfeited, as applicable, is applied to the shortened performance period.

Post-Termination Benefits Table

The table below shows the amounts that would be payable to each of our named executive officers in connection with a termination without cause or for good reason in contemplation of or following a change of control. The amounts below are calculated as if such event had occurred on December 29, 2006, based on our closing stock price on that day of $17.23. Other assumptions that were made in order to calculate these amounts are that no accrued base salary or prorated incentive payment was owed on that date and all accelerated options were exercised on the termination date. The change-in-control agreements provide enhancements to the benefit formula of the supplemental executive retirement plan, and the retirement related benefits shown below are incremental amounts that represent the enhanced benefit only. The supplemental executive retirement plan is described in more detail in the Pension Benefits section above, and the present value of accumulated benefits under our pension arrangements are shown in that section. Any value of such arrangements that is not directly attributable to the change in control is not included in this section. Health care benefits are based on the continuation of benefits for three years at the officer's current level of coverage. Under the terms of our change-in-control agreements, executive officers are eligible to receive an excise tax gross-up payment if additional taxes are due by that officer as a result of the application of the excise tax associated with Section 280G of the Internal Revenue Code; there is no income tax gross-up. There are no agreements or arrangements with the named executive officers for any termination scenarios not involving a change in control.

Name	S. W. Hudson	J. B. Ramil	G. L. Gillette	C. R. Black	W. N. Cantrell
Cash Severance	$3,952,500	$2,475,000	$1,985,550	$1,552,500	$1,449,000
Accelerated Equity Vesting	2,226,125	1,682,385	1,119,330	563,425	758,765
Retirement Related Benefits	0	1,409,419	744,807	902,892	$495,850
Health Care Benefits	27,995	38,525	38,525	27,995	27,995
Excise Tax Gross-Up	1,839,485	2,677,813	1,928,453	1,193,941	1,084,458
Total	$8,046,105	$8,283,143	$5,816,664	$4,240,753	$3,816,068

Item 2 - Ratification of Appointment of Auditor

The Audit Committee has appointed the firm of PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as our independent auditor for 2007. Although ratification by the shareholders is not required by our bylaws or otherwise, 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. In the event this ratification is not received, the Audit Committee will reconsider the selection of PricewaterhouseCoopers LLP.

Representatives of PricewaterhouseCoopers LLP are expected to be present at the 2007 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 our independent auditor to conduct the annual audit of the financial statements for the fiscal year ending December 31, 2007.

Fees Paid to the Independent Auditor

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers LLP for the audit of our annual financial statements for the years ended December 31, 2005 and December 31, 2006, and fees billed for other services rendered by PricewaterhouseCoopers LLP during these periods.

	2006	*2005*
Audit fees	$1,940,000	$2,300,000
Audit-related fees	175,000	195,000
Tax fees		
Tax compliance fees	35,000	35,000
Tax planning fees	10,000	10,000
All other fees	5,000	5,000
Total	2,165,000	$2,545,000

Audit fees consisted of fees for professional services performed for the audit of our annual financial statements, including management's assessment of our internal control over financial reporting, and review of financial statements included in our 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 our financial statements, principally for the audit of benefit plans and consultations with our 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 policy for pre-approval of services to be provided by our independent auditor. Under the policy, the Audit Committee pre-approves the annual audit engagement terms and fees and the specific types of services to be performed by the independent auditor throughout the year, based on the Audit Committee's determination that the provision of the services would not be likely to impair the auditor's independence. The pre-approval is effective for the current fiscal year and until the Audit Committee meets to re-approve services for the following year, or such other period as the Committee may designate. 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 us have been pre-approved by the Audit Committee.

Audit Committee Report

The Audit Committee is composed of five 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 our financial statements, (b) the annual independent audit process, (c) our systems of internal control over financial reporting and disclosure controls and procedures, (d) the independence and performance of our independent auditor and (e) our 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 Investors page of our website, www.tecoenergy.com.

In the course of its oversight of our financial reporting process, the Committee has:

1. Reviewed and discussed with management our audited financial statements, including Management's Discussion and Analysis, for the fiscal year ended December 31, 2006;
2. Discussed with PricewaterhouseCoopers LLP, our 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 non-audit 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 our Annual Report on Form 10-K for the year ended December 31, 2006 for filing with the Securities and Exchange Commission.

By the Audit Committee,
J. Thomas Touchton (Chairman)
James L. Ferman, Jr.
Joseph P. Lacher
Tom L. Rankin
Paul L. Whiting

Other Information

Shareholder Proposals and Nominations

In order for proposals of shareholders to be considered for inclusion in our proxy materials relating to the annual meeting of shareholders in 2008 pursuant to Rule 14a-8 of the Exchange Act, they must be received on or before November 22, 2007. In order for a shareholder proposal made outside of Rule 14a-8 of the Exchange Act to be considered "timely" under Rule 14a-4(c) of that Act, it must be received by us not later than February 2, 2008. Any proposals should be sent to: Corporate Secretary, TECO Energy, Inc., P.O. Box 111, Tampa, Florida 33601.

Under our bylaws, in order for a shareholder to bring business before or propose director nominations at an annual meeting, the shareholder must give written notice to our Secretary 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 our employees. We have 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 us.

Householding of Annual Meeting Materials

Some banks, brokers and other nominee record holders may be "householding" our 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. We will promptly deliver a separate copy of either document to shareholders who write or call us 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 21, 2007

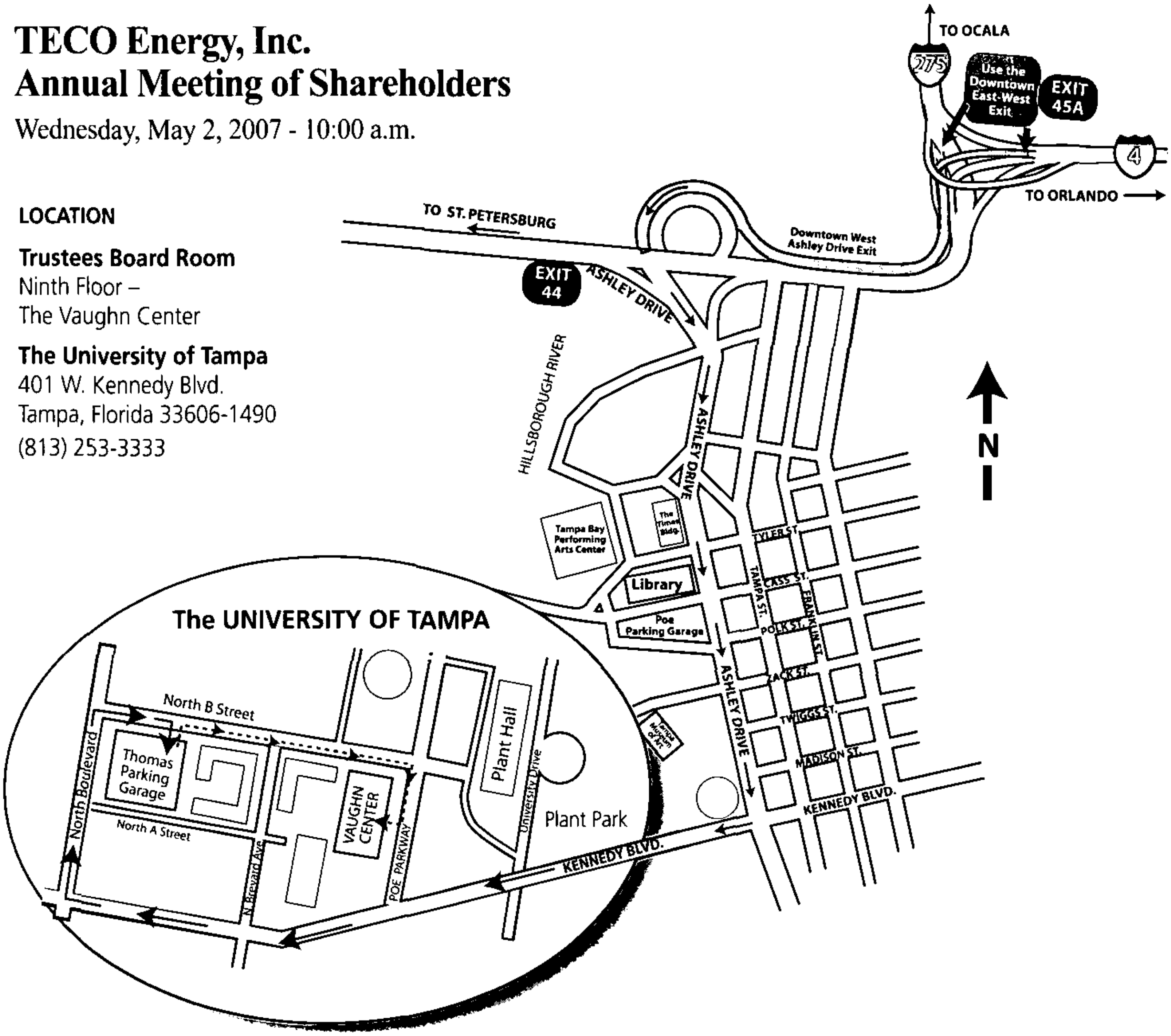
TECO Energy, Inc.
Annual Meeting of Shareholders

Wednesday, May 2, 2007 - 10:00 a.m.

LOCATION

Trustees Board Room
Ninth Floor –
The Vaughn Center

The University of Tampa
401 W. Kennedy Blvd.
Tampa, Florida 33606-1490
(813) 253-3333



Directions to The University of Tampa's Vaughn Center, from I-275 or I-4:

- From Interstate 275 – coming from **St. Petersburg**:
  - Take Tampa downtown **EXIT 44 – Ashley Dr./Scott St./Tampa St.**;
- From Interstate 275 coming from **Ocala**, or coming from Interstate 4 – **Orlando**:
  - Take Tampa downtown **EXIT 45A – Downtown Tampa East-West**;
- Then follow the directional sign to **Downtown West – Ashley Drive**;
- Coming off Exit Ramps 44 or 45A, Ashley Drive will split to the right, with Tampa Street to the left – stay on **Ashley Drive**;
- Continue south on Ashley Drive in the right hand lane for approximately 5 blocks until you come to **Kennedy Blvd**;
- Turn right onto **Kennedy Blvd.** and cross over the bridge, staying in the right lane;
- Continue west on Kennedy Blvd, pass two entrances to The University of Tampa until you come to **North Blvd.**;
- Turn right onto North Blvd., go up 2 blocks, and turn right again onto **North B Street**;
- The multi-story **Thomas Parking Garage** will be on your immediate right at that corner – turn right into the parking garage;
- Once parked, walk along North B Street toward The University of Tampa's Plant Hall, until you come to the **Vaughn Center** building -
  - A small bus will be available for shareholders needing assistance to the Vaughn Center;
- The Annual Meeting of Shareholders is being held on the **ninth floor** of the Vaughn Center's **Trustees Board Room**.

TECO ENERGY EXECUTIVE OFFICERS

SHERRILL W. HUDSON
Chairman of the Board and Chief Executive Officer

JOHN B. RAMIL
President and Chief Operating Officer

CHARLES R. BLACK
President, Tampa Electric

WILLIAM N. CANTRELL
President, Peoples Gas System

SAL LITRICO
President, TECO Transport

J. J. SHACKLEFORD
President, TECO Coal

CLINTON E. CHILDRESS
Senior Vice President - Corporate Services and Chief Human Resources Officer

GORDON L. GILLETTE
Executive Vice President and Chief Financial Officer and President, TECO Guatemala

SHEILA M. MCDEVITT
Senior Vice President - General Counsel and Chief Legal Officer

TECO ENERGY STAFF OFFICERS

CHARLES A. ATTAL III
Vice President - Deputy General Counsel

PHIL L. BARRINGER
Vice President - Controller, Operations

SANDRA W. CALLAHAN
Vice President - Treasury and Risk Management (Treasurer and Chief Accounting Officer)

R. BRUCE CHRISTMAS
Vice President - Fuels Management

CHARLES O. HINSON III
Vice President - State Government Affairs

BURNIS KILPATRICK, JR.
Corporate Compliance Officer

KAREN M. MINCEY
Vice President - Information Technology and Chief Information 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.

DUBOSE AUSLEY(3)
Attorney and former Chairman, Ausley & McMullen, P.A. (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)(4)
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.

JOSEPH P. LACHER(1)
Former President of Florida Operations for BellSouth Telecommunications, Inc., Miami, Florida; also former Chairman, Great Florida Bank, Miami, Florida.

LORETTA A. PENN(2)
Vice President, Spherion Corporation (staffing and professional services), McLean, Virginia.

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).

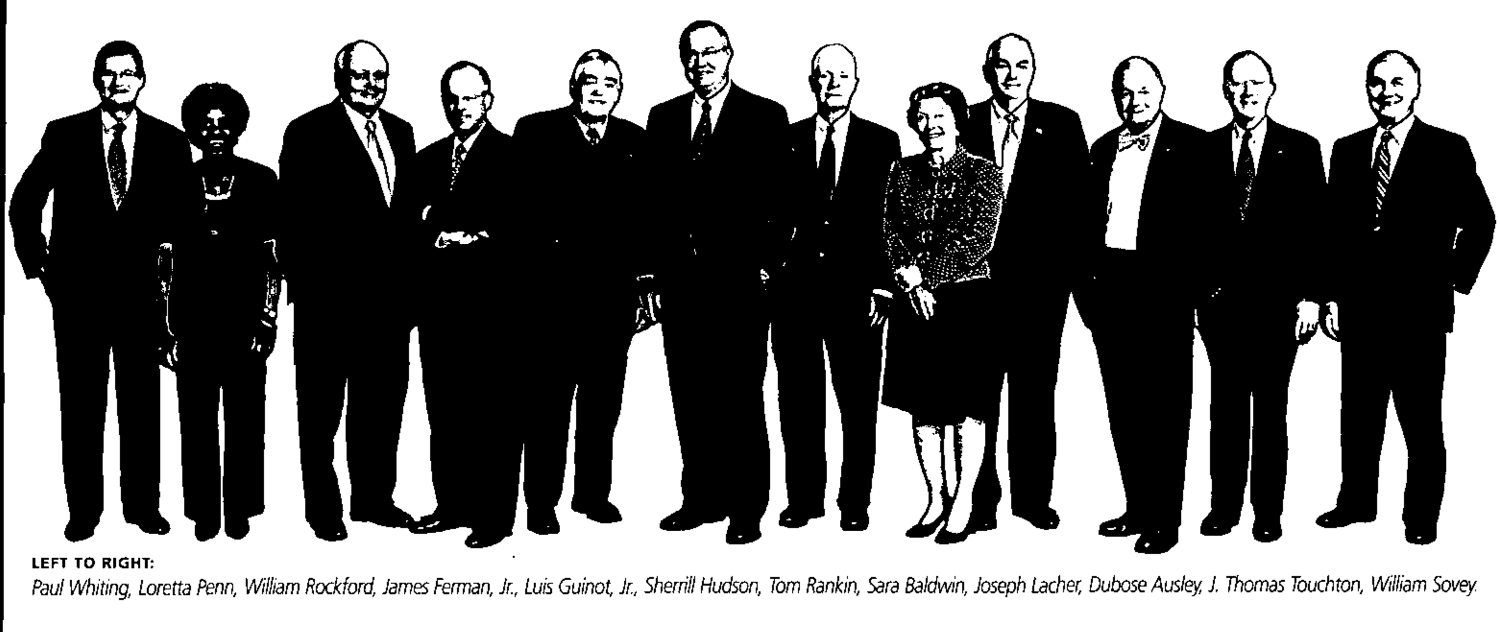
WILLIAM D. ROCKFORD(3)
Former President, Primary Energy Ventures LLC (power generation), Oak Brook, Illinois; also former Managing Director, Chase Securities Inc. (financial services), New York, New York.

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 investments), Tampa, Florida.

PAUL L. WHITING(1)(2)
President, Seabreeze Holdings, Inc., (consulting and private investments), Tampa, Florida and Chairman of the Board, Sykes Enterprises, Inc. (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



LEFT TO RIGHT:
Paul Whiting, Loretta Penn, William Rockford, James Ferman, Jr., Luis Guinot, Jr., Sherrill Hudson, Tom Rankin, Sara Baldwin, Joseph Lacher, Dubose Ausley, J. Thomas Touchton, William Sovey

SARA L. BALDWIN, *a member of the TECO Energy Board of Directors for 27 years, is retiring in May 2007. The company thanks Sally for her leadership and service. Her many contributions will be missed.*

Information for Investors

INTERNET

Current information about TECO Energy is on the Internet at **tecoenergy.com**

TECO Energy is listed on the New York Stock Exchange under the symbol TE.

TECO ENERGY OFFICES

702 N. Franklin Street
Tampa, FL 33602
813-228-1111
813-228-4262 fax

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 May 2, 2007, 10:00 a.m. at:
The University of Tampa - Vaughn Center
401 W. Kennedy Blvd.
Tampa, FL 33606

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 or 212-815-3700 (outside the U.S. and Canada)
By e-mail: shareowners@bankofny.com
By Web: www.stockbny.com

TRANSFER AGENT & REGISTRAR

The Bank of New York
Receive and Deliver Department
P.O. Box 11002
Church Street Station
New York, NY 10286-1258
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/TECO Energy, Inc.
P.O. Box 1958
Newark, NJ 07101-1958

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 "Investors" section of our Web site at **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 33601-0111

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

TECO ENERGY

P. O. Box 111 Tampa, FL 33601
tecoenergy.com

The cover and pages 1-8 of this annual report are printed on paper containing 30% post-consumer recycled fiber. This paper is certified by Green Seal, and meets the EPA guidelines for recycled papers. This paper was also manufactured with renewable, non-polluting, wind-generated energy.

The financial section of this report is printed on paper made with 10% post-consumer and processed elemental chlorine-free (ECF) recycled fiber.

MOHAWK wind power

END