AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

123 SOUTH CALHOUN STREET
P.O. BOX 391 (ZIP 32302)
TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

March 28, 2014

VIA: ELECTRONIC FILING

Ms. Carlotta S. Stauffer
Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Application of Tampa Electric Company for authority to issue and sell securities pursuant to Section 366.04, F.S. and Chapter 25-8, F.A.C. during the twelve months ending December 31, 2013; Docket No. 120233-EI

Dear Ms. Stauffer:

Pursuant to Rule 25-8.009, Florida Administrative Code, and this Commission's Order No. PSC-12-0603-FOF-EI issued November 5, 2012, attached is Tampa Electric Company's Consummation Report regarding the issuance and sale of securities during the fiscal year ended December 31, 2013.

Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Attachment

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Application of Tampa Electric Company	)	
For Authority to Issue and Sell Securities Pursuant	)	
To Section 366.04, F.S., and Chapter 25-8, F.A.C.	)	DOCKET NO. 120233-EI
During the Twelve Months Ending	)	FILED: March 28, 2014
December 31, 2013	)	
	)	

CONSUMMATION REPORT

The applicant, Tampa Electric Company (the "Company"), pursuant to Commission Order No. PSC-12-0603-FOF-EI dated November 5, 2012, submits the following information with respect to the issuance and/or sale of securities during the twelve months ending December 31, 2013.

Facts of Issues

The Company regularly borrows under its two revolving credit facilities, both of which permit the Company to draw down, repay and re-borrow funds. Given the frequency of these borrowings and repayments, it is not practicable to give the details of each action. However, the Company's borrowing activity in 2013 can be summarized as follows:

	($Millions)
Minimum Outstanding	$ 0
Maximum Outstanding	$ 84.0
Average Outstanding	$ 5.4
Weighted Average Interest Cost	0.59%

Statement of Capitalization

Statements of capitalization, pretax interest coverage, debt interest requirements and preferred stock dividend requirements of the Company for the year ending December 31, 2013 are as follows:

Capital Structure	($Millions)
Short-term Debt	$ 84.0
Long-term Debt	1,880.8
Preferred Stock	-
Common Equity	2,330.7
Total Capitalization	$4,295.5

Pretax Interest Coverage	
Including AFUDC	4.31 times
Excluding AFUDC	4.46 times
Debt Interest Requirements	$108.9
Preferred Stock Dividends	-

Respectfully submitted this 28th day of March 2014

TAMPA ELECTRIC COMPANY

By: Kim Caruso

Kim M. Caruso
Treasurer

Consummation Report

Exhibit List

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

FORM 10-K

_X_ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2013**

OR

___ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____

Commission File No.	Exact name of each Registrant as specified in its charter, state of incorporation, address of principal executive offices, telephone number	I.R.S. Employer Identification Number
1-8180	**TECO ENERGY, INC.** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	**59-2052286**
1-5007	**TAMPA ELECTRIC COMPANY** (a Florida corporation) TECO Plaza 702 N. Franklin Street Tampa, Florida 33602 (813) 228-1111	**59-0475140**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
TECO Energy, Inc. Common Stock, $1.00 par value	New York Stock Exchange

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

Indicate by check mark if TECO Energy, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES [X] NO [ ]

Indicate by check mark if Tampa Electric Company is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
YES [ ] NO [X]

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.
YES [ ] NO [X]

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

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

YES [X] NO [ ]

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

Indicate by check mark whether TECO Energy, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [ ]

Indicate by check mark whether Tampa Electric Company is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer [ ] Accelerated filer [ ] Non-accelerated filer [X] Smaller reporting company [ ]

Indicate by check mark whether TECO Energy, Inc. is a shell company (as defined in Rule 12b-2 of the Act).

YES [ ] NO [X]

Indicate by check mark whether Tampa Electric Company is a shell company (as defined in Rule 12b-2 of the Act).

YES [ ] NO [X]

The aggregate market value of TECO Energy, Inc.'s common stock held by non-affiliates of the registrant as of June 28, 2013 was approximately $3.69 billion based on the closing sale price as reported on the New York Stock Exchange.

The aggregate market value of Tampa Electric Company's common stock held by non-affiliates of the registrant as of June 28, 2013 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 13, 2014 was 218,067,617. As of Feb. 13, 2014, there were 10 shares of Tampa Electric Company's common stock issued and outstanding, all of which were held, beneficially and of record, by TECO Energy, Inc.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement relating to the 2014 Annual Meeting of Shareholders of TECO Energy, Inc. are incorporated by reference into Part III.

Tampa Electric Company meets the conditions set forth in General Instruction (I) (1) (a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format.

This combined Form 10-K represents separate filings by TECO Energy, Inc. and Tampa Electric Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Tampa Electric Company makes no representations as to the information relating to TECO Energy, Inc.'s other operations.

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DEFINITIONS

Acronyms and defined terms used in this and other filings with the U.S. Securities and Exchange Commission include the following:

Term	**Meaning**
ABS	asset-backed security
ADR	American depository receipt
AFUDC	allowance for funds used during construction
AFUDC - debt	debt component of allowance for funds used during construction
AFUDC - equity	equity component of allowance for funds used during construction
AMT	alternative minimum tax
AOCI	accumulated other comprehensive income
APBO	accumulated postretirement benefit obligation
ARO	asset retirement obligation
BACT	Best Available Control Technology
BTU	British Thermal Unit
CAA	Federal Clean Air Act
CAIR	Clean Air Interstate Rule
capacity clause	capacity cost-recovery clause, as established by the FPSC
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980
CCRs	coal combustion residuals
CGESJ	Central Generadora Eléctrica San José, Limitada, owner of the San José Power Station in Guatemala
CMMA	Cardno Marshall Miller & Associates
CMBS	commercial mortgage-backed securities
CMO	collateralized mortgage obligation
CNG	compressed natural gas
CPI	consumer price index
CSAPR	Cross State Air Pollution Rule
CO_2	carbon dioxide
CT	combustion turbine
DECA II	Distribución Eléctrica Centro Americana, II, S.A.
DOE	U.S. Department of Energy
DR-CAFTA	Dominican Republic Central America – United States Free Trade Agreement
ECRC	environmental cost recovery clause
EEGSA	Empresa Eléctrica de Guatemala, S.A., the largest private distribution company in Central America
EEI	Edison Electric Institute
EGWP	Employee Group Waiver Plan
EPA	U.S. Environmental Protection Agency
EPS	earnings per share
ERISA	Employee Retirement Income Security Act
EROA	expected return on plan assets
ERP	enterprise resource planning
FASB	Financial Accounting Standards Board
FDEP	Florida Department of Environmental Protection
FERC	Federal Energy Regulatory Commission
FGT	Florida Gas Transmission Company
FPSC	Florida Public Service Commission
fuel clause	fuel and purchased power cost-recovery clause, as established by the FPSC
GAAP	generally accepted accounting principles
GHG	greenhouse gas(es)
HCIDA	Hillsborough County Industrial Development Authority
HPP	Hardee Power Partners
ICSID	International Centre for the Settlement of Investment Disputes
IFRS	International Financial Reporting Standards

IGCC	integrated gasification combined-cycle
IOU	investor owned utility
IRS	Internal Revenue Service
ISDA	International Swaps and Derivatives Association
ISO	independent system operator
ITCs	investment tax credits
KW	Kilowatt(s)
KWH	kilowatt-hour(s)
LIBOR	London Interbank Offered Rate
MAP-21	Moving Ahead for Progress in the 21st Century Act
MBS	mortgage-backed securities
MD&A	Management's Discussion and Analysis
Met	metallurgical
MMA	The Medicare Prescription Drug, Improvement and Modernization Act of 2003
MMBTU	one million British Thermal Units
MRV	market-related value
MSHA	Mine Safety and Health Administration
MW	megawatt(s)
MWH	megawatt-hour(s)
NAESB	North American Energy Standards Board
NAV	net asset value
NERC	North American Electric Reliability Corporation
NMGC	New Mexico Gas Company, Inc., the principal subsidiary of NMGI
NMGI	New Mexico Gas Intermediate, Inc.
NMPRC	New Mexico Public Regulation Commission
NOL	net operating loss
Note __	Note__ to consolidated financial statements
NO_x	nitrogen oxide
NPNS	normal purchase normal sale
NYMEX	New York Mercantile Exchange
O&M expenses	operations and maintenance expenses
OATT	open access transmission tariff
OCI	other comprehensive income
OTC	over-the-counter
OTTI	other than temporary impairment
PBGC	Pension Benefit Guarantee Corporation
PBO	postretirement benefit obligation
PCI	pulverized coal injection
PCIDA	Polk County Industrial Development Authority
PGA	purchased gas adjustment
PGS	Peoples Gas System, the gas division of Tampa Electric Company
PM	particulate matter
PPA	power purchase agreement
PPSA	Power Plant Siting Act
PRP	potentially responsible party
PUHCA 2005	Public Utility Holding Company Act of 2005
REIT	real estate investment trust
REMIC	real estate mortgage investment conduit
RFP	request for proposal
ROE	return on common equity
Regulatory ROE	return on common equity as determined for regulatory purposes
RPS	renewable portfolio standards

RTO	regional transmission organization
S&P	Standard and Poor's
SCR	selective catalytic reduction
SEC	U.S. Securities and Exchange Commission
SO_2	sulfur dioxide
SERP	Supplemental Executive Retirement Plan
SPA	stock purchase agreement
STIF	short-term investment fund
Tampa Electric	Tampa Electric, the electric division of Tampa Electric Company
TCAE	Tampa Centro Americana de Electridad, Limitada, majority owner of the Alborada Power Station
TEC	Tampa Electric Company, the principal subsidiary of TECO Energy, Inc.
TECO Diversified	TECO Diversified, Inc., a subsidiary of TECO Energy, Inc. and parent of TECO Coal Corporation
TECO Coal	TECO Coal Corporation, and its subsidiaries, a coal producing subsidiary of TECO Diversified
TECO Finance	TECO Finance, Inc., a financing subsidiary for the unregulated businesses of TECO Energy, Inc.
TECO Guatemala	TECO Guatemala, Inc., a subsidiary of TECO Energy, Inc., parent company of formerly owned generating and transmission assets in Guatemala.
TEMSA	Tecnología Marítima, S.A., a provider of dry bulk and coal unloading services located in Guatemala
TGH	TECO Guatemala Holdings, LLC
TRC	TEC Receivables Company
USACE	U.S. Army Corps of Engineers
VIE	variable interest entity
WRERA	The Worker, Retiree and Employer Recovery Act of 2008

PART I

Item 1. BUSINESS.

TECO ENERGY

TECO Energy, Inc. (TECO Energy) was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of Tampa Electric Company. TECO Energy and its subsidiaries had approximately 3,900 employees as of Dec. 31, 2013.

TECO Energy's Corporate Governance Guidelines, the charter of each committee of the Board of Directors, and the code of ethics applicable to all directors, officers and employees, the *Code of Ethics and Business Conduct*, are available on the Investors section of TECO Energy's website, www.tecoenergy.com, or in print free of charge to any investor who requests the information. TECO Energy also makes its SEC (www.sec.gov) filings available free of charge on the Investors section of TECO Energy's website as soon as reasonably practicable after they are filed with or furnished to the SEC.

TECO Energy is a holding company for regulated utilities and other businesses. TECO Energy currently owns no operating assets but holds all of the common stock of TEC and, through its subsidiary TECO Diversified, owns TECO Coal.

Unless otherwise indicated by the context, "TECO Energy" or the "company" means the holding company, TECO Energy, Inc. and its subsidiaries, and references to individual subsidiaries of TECO Energy, Inc. refer to that company and its respective subsidiaries. TECO Energy's business segments and revenues for those segments, for the years indicated, are identified below.

TEC, a Florida corporation and TECO Energy's largest subsidiary, has two business segments. Its **Tampa Electric** division provides retail electric service to almost 700,000 customers in West Central Florida with a net winter system generating capacity of 4,668 MW. **PGS**, the gas division of TEC, is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in Florida. With almost 350,000 customers, PGS has operations in Florida's major metropolitan areas. Annual natural gas throughput (the amount of gas delivered to its customers, including transportation-only service) in 2013 was almost 1.7 billion therms.

TECO Coal, a Kentucky corporation, has 10 subsidiaries located in Eastern Kentucky, Tennessee and Virginia. These entities own mineral rights, own or operate surface and underground mines and own interests in coal processing and loading facilities.

Revenues from Continuing Operations

(millions)	*2013*	*2012*	*2011*
Tampa Electric	$ 1,950.5	$ 1,981.3	$ 2,020.6
PGS	393.5	398.9	453.5
Total regulated businesses	$ 2,344.0	$ 2,380.2	$ 2,474.1
TECO Coal	496.2	608.9	733.0
Other	11.1	7.5	2.8
Total revenues from continuing operations	$ 2,851.3	$ 2,996.6	$ 3,209.9

For additional financial information regarding TECO Energy's significant business segments including geographic areas, see **Note 14** to the TECO Energy **Consolidated Financial Statements**.

Discontinued Operations/Asset Dispositions

TECO Guatemala, a Florida corporation, owned subsidiaries that participated in two contracted Guatemalan power plants, Alborada and San José. TECO Energy, Inc. completed the sale of its generating and transmission assets in Guatemala during 2012 as part of a business strategy to focus on the domestic electric and gas utilities.

On Sept. 27, 2012, TECO Guatemala entered into an agreement to sell all of the equity interests in the Alborada and San José power stations, related facilities and operations in Guatemala, for a total purchase price of $227.5 million in cash. The sale of the Alborada Power Station closed on the same date for a selling price of $12.5 million.

On Dec. 19, 2012, the closing occurred on the sale of the San José Power Station and related facilities in Guatemala for a purchase price of $215.0 million.

See **Notes 19, 20** and **21** to the **TECO Energy, Inc. Consolidated Financial Statements** for more information regarding these discontinued operations and asset dispositions.

Pending Acquisition of NMGI

In May 2013, TECO Energy announced it had entered into an agreement to purchase all of the capital stock of NMGI, the parent company of NMGC. Completion of the acquisition is subject to various customary conditions, including, among others, receipt of all required regulatory approvals. For more information regarding this pending acquisition, see **MD&A-Pending Acquisition of NMGI**.

TAMPA ELECTRIC – Electric Operations

TEC was incorporated in Florida in 1899 and was reincorporated in 1949. TEC is a public utility operating within the State of Florida. Its Tampa Electric division is engaged in the generation, purchase, transmission, distribution and sale of electric energy. The retail territory served comprises an area of about 2,000 square miles in West Central Florida, including Hillsborough County and parts of Polk, Pasco and Pinellas Counties, with an estimated population of over one million. The principal communities served are Tampa, Temple Terrace, Winter Haven, Plant City and Dade City. In addition, Tampa Electric engages in wholesale sales to utilities and other resellers of electricity. It has three electric generating stations in or near Tampa, one electric generating station in southwestern Polk County, Florida and one electric generating station in long-term reserve standby located near Sebring, a city in Highlands County in South Central Florida.

Tampa Electric had 2,385 employees as of Dec. 31, 2013, of which 895 were represented by the International Brotherhood of Electrical Workers and 178 were represented by the Office and Professional Employees International Union.

In 2013, approximately 48% of Tampa Electric's total operating revenue was derived from residential sales, 30% from commercial sales, 9% from industrial sales and 13% from other sales, including bulk power sales for resale. Approximately 5% of revenues were attributable to governmental municipalities. The sources of operating revenue and MWH sales for the years indicated were as follows:

Operating Revenue

(millions)	*2013*	*2012*	*2011*
Residential	$ 936.8	$ 958.9	$ 994.7
Commercial	581.2	612.3	612.6
Industrial – Phosphate	71.9	75.7	62.0
Industrial – Other	100.4	101.2	99.3
Other retail sales of electricity	177.4	184.0	185.2
Total retail	1,867.7	1,932.1	1,953.8
Sales for resale	8.5	16.2	21.7
Other	74.3	33.0	45.1
Total operating revenues	$ 1,950.5	$ 1,981.3	$ 2,020.6

Megawatt-hour Sales

(thousands)	*2013*	*2012*	*2011*
Residential	8,470	8,395	8,718
Commercial	6,090	6,185	6,207
Industrial	2,026	2,002	1,804
Other retail sales of electricity	1,832	1,827	1,835
Total retail	18,418	18,409	18,564
Sales for resale	222	267	352
Total energy sold	18,640	18,676	18,916

No significant part of Tampa Electric's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on Tampa Electric. Tampa Electric's business is not highly seasonal, but winter peak loads are experienced due to electric space heating, fewer daylight hours and colder temperatures and summer peak loads are experienced due to the use of air conditioning and other cooling equipment.

Regulation

Tampa Electric's retail operations 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 provides an opportunity for the utility to collect total revenues (revenue requirements) equal to its cost to provide service, plus a reasonable return on invested capital.

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

Tampa Electric's results for the first ten months of 2013, and all of 2012 and 2011, reflect base rates established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE midpoint of 11.25%, 54.0% equity in the capital structure and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for CTs and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

On Feb. 4, 2013, Tampa Electric delivered a letter to the FPSC notifying it of its intent to file a request for an increase in its retail base rates and service charges. On April 5, 2013, Tampa Electric filed a petition with the FPSC requesting, among other things, a permanent increase in rates and service charges sufficient to generate additional annual revenues of approximately $134.8 million, to be effective on or after Jan. 1, 2014. The request provided for a return on equity range of 10.25% to 12.25% with a midpoint of 11.25%. The petition also requested certain changes to existing rate schedules, as well as the adoption of new rate designs.

On Sept. 6, 2013, TEC and all of the intervenors in its Tampa Electric division base rate proceeding filed with the FPSC a joint motion for the FPSC to approve a stipulation and settlement agreement, which would resolve all matters in Tampa Electric's pending base rate proceeding.

This agreement provided for the following revenue increases: $57.5 million effective Nov. 1, 2013, an additional $7.5 million effective Nov. 1, 2014, an additional $5.0 million effective Nov. 1, 2015, and an additional $110.0 million effective Jan. 1, 2017 or the date that an expansion of TEC's Polk Power Station goes into service, whichever is later. The agreement provides that Tampa Electric's allowed regulatory ROE would be a mid-point of 10.25% with a range of plus or minus 1%, with a potential increase to 10.50% if U.S. Treasury bond yields exceed a specified threshold. The agreement provides that Tampa Electric cannot file for additional rate increases until 2017 (to be effective in 2018), unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE is increased as described above) any party to the agreement other than TEC could seek a review of Tampa Electric's base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital, Tampa Electric will begin using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013 and effective Nov. 1, 2013, Tampa Electric ceased accruing $8.0 million annually to the FERC-authorized and FPSC-approved self-insured storm damage reserve.

On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement between TEC and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved Tampa Electric's base rate proceeding.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services and accounting practices.

Non-power goods-and-services transactions between Tampa Electric and its affiliates are subject to regulation by the FPSC and FERC, and any charges deemed to be imprudently incurred may be disallowed for recovery from Tampa Electric's retail and wholesale customers.

On Nov. 6, 2012, Tampa Electric received notification from the FERC that its accounting practices and financial reporting processes would be audited, along with its compliance with the FERC's records retention requirements. This was considered a routine audit by the FERC staff, though it has been approximately 20 years since Tampa Electric last had a FERC accounting audit.

No material issues have been identified as a result of the audit, and Tampa Electric expects to have an "exit" audit conference with the FERC staff in 2014 and thereafter to receive a letter from the FERC describing the results of the completed audit.

By June 30, 2014, the company will file its required triennial market-power analysis, demonstrating that the company does not have wholesale market power using FERC's two analytical screens. This compliance filing is made in support of the company's continued ability to affect wholesale market-based rate transactions everywhere, except within Tampa Electric's balancing-authority area.

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 the **Environmental Matters** section).

Competition

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. Distributed generation could also be a source of competition in the future, but has not been a significant factor to date. Tampa Electric intends to retain and expand its retail business by managing costs and providing quality service to retail customers.

Unlike the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including approximately 30 other investor-owned, municipal and other utilities, as well as co-generators and other unregulated power generators with uncontracted excess capacity. Entities compete to provide energy on a short-term basis (i.e., hourly or daily) and on a long-term basis. Competition in these markets is primarily based on having available energy to sell to the wholesale market and the price. In Florida, available energy for the wholesale markets is affected by the state's PPSA, which sets the state's electric energy and environmental policy, and governs the building of new generation involving steam capacity of 75 MW or more. The PPSA requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. The effect of the PPSA has been to limit the number of unregulated generating units with excess capacity for sale in the wholesale power markets in Florida.

Tampa Electric is not a major participant in the wholesale market because it uses its lower cost generation to serve its retail customers rather than the wholesale market. Over the past three years, gross revenues from wholesale sales, which include fuel that is a pass-through cost, have averaged less than 1% of Tampa Electric's total revenue.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring IOUs, such as Tampa Electric, 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 MW. These rules, which allow independent power producers and others to bid to supply the new generating capacity, 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 that the self-build option is deemed the most cost-effective.

Fuel

Approximately 61% of Tampa Electric's generation of electricity for 2013 was coal-fired, with natural gas representing approximately 39% and oil representing less than 1%. Tampa Electric used its generating units to meet approximately 92% of the total system load requirements, with the remaining 8% coming from purchased power. Tampa Electric's average delivered fuel cost per MMBTU and average delivered cost per ton of coal burned have been as follows:

Average cost per MMBTU	*2013*	*2012*	*2011*	*2010*	*2009*
Coal	$ 3.36	$ 3.57	$ 3.46	$ 3.08	$ 3.05
Oil	30.01	25.88	21.21	16.43	16.01
Gas (Natural)	5.23	5.34	6.20	6.74	8.00
Composite	4.00	4.19	4.38	4.46	5.02
Average cost per ton of coal burned	77.79	84.59	83.17	74.80	72.98

Tampa Electric's generating stations burn fuels as follows: Bayside Station burns natural gas; Big Bend Station, which has SO_2 scrubber capabilities and NO_x reduction systems, burns a combination of high-sulfur coal and petroleum coke, No. 2 fuel oil and natural gas at CT4; Polk Power Station burns a blend of low-sulfur coal and petroleum coke (which is gasified and subject to sulfur and particulate matter removal prior to combustion), natural gas and oil; and Phillips Station, which burned residual fuel oil and was placed on long-term standby in September 2009.

Coal. Tampa Electric burned approximately 4.7 million tons of coal and petroleum coke during 2013 and estimates that its combined coal and petroleum coke consumption will be about 4.9 million tons in 2014. During 2013, Tampa Electric purchased approximately 83% of its coal under long-term contracts with five suppliers, and approximately 17% of its coal and petroleum coke in the spot market. Tampa Electric expects to obtain approximately 81% of its coal and petroleum coke requirements in 2014 under long-term contracts with six suppliers and the remaining 19% in the spot market.

Tampa Electric's long-term contracts provide for revisions in the base price to reflect changes in several important cost factors and for suspension or reduction of deliveries if environmental regulations should prevent Tampa Electric from burning the coal supplied, provided that a good faith effort has been made to continue burning such coal.

In 2013, approximately 85% of Tampa Electric's coal supply was deep-mined, approximately 8% was surface-mined and the remaining was petroleum coke. Federal surface-mining laws and regulations have not had any material adverse impact on Tampa Electric's coal supply or results of its operations. Tampa Electric cannot predict, however, the effect of any future mining laws and regulations.

Natural Gas. As of Dec. 31, 2013, approximately 48% of Tampa Electric's 1,250,000 MMBTU gas storage capacity was full. Tampa Electric has contracted for 80% of its expected gas needs for the April 2014 through October 2014 period. In early March 2014, to meet its generation requirements, Tampa Electric expects to issue RFPs to meet its remaining 2014 gas needs and begin contracting for its 2015 gas needs. Additional volume requirements in excess of projected gas needs are purchased on the short-term spot market.

Oil. Tampa Electric has agreements in place to purchase low sulfur No. 2 fuel oil for its Big Bend and Polk Power stations. All of these agreements have prices that are based on spot indices.

Franchises and Other Rights

Tampa Electric holds franchises and other rights that, together with its charter powers, govern the placement of Tampa Electric's facilities on the public rights-of-way as it carries for its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing Tampa Electric's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and not subject to amendment without the consent of Tampa Electric (except to the extent certain city ordinances relating to permitting and like matters are modified from time to time), although, in certain events, they are subject to forfeiture.

Florida municipalities are prohibited from granting any franchise for a term exceeding 30 years. The City of Temple Terrace reserved the right to purchase Tampa Electric's property used in the exercise of its franchise if the franchise is not renewed. In the absence of such right to purchase, based on judicial precedent, if the franchise agreement is not renewed, Tampa Electric would be able to continue to use public rights-of-way within the municipality, subject to reasonable rules and regulations imposed by the municipalities.

Tampa Electric has franchise agreements with 13 incorporated municipalities within its retail service area. These agreements have various expiration dates through August 2043.

Franchise fees payable by Tampa Electric, which totaled $42.8 million at Dec. 31, 2013, are calculated using a formula based primarily on electric revenues and are collected on customers' bills.

Utility operations in Hillsborough, Pasco, Pinellas and Polk Counties outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the County Commissioners of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates for the Hillsborough County, Pinellas County and Polk County agreements. The agreement covering electric operations in Pasco County expires in 2023.

Environmental Matters

Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act, and material Clean Water Act implications and impacts by federal and state legislative initiatives. TEC, through its Tampa Electric and PGS divisions, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites.

Air Quality Control

Emission Reductions

Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., IGCC) and conversion of coal-fired units to natural-gas fired combined cycle; implementation of a responsible fuel mix taking into account price and reliability impacts to its customers; a substantial capital expenditure program to add BACT emissions controls; implementation of additional controls to accomplish early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

Tampa Electric, through voluntary negotiations in 1999 with the EPA, the U.S. Department of Justice and the FDEP, signed a Consent Decree and Consent Final Judgment, as settlement of federal and state litigation to dramatically decrease emissions from its power plants. Tampa Electric has fulfilled the obligations of the Consent Decree and the court terminated the Consent Decree on November 22, 2013. Termination of the Consent Final Judgment is in progress and is expected to be completed during the first half of 2014.

The emission reduction requirements of these agreements resulted in the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (Bayside Power Station), enhanced availability of flue-gas desulfurization systems (scrubbers) at Big Bend Station to help reduce SO_2, and installation of SCR systems for NO_x reduction on Big Bend Units 1 through 4. Cost recovery for the SCRs began for each unit in the year that the unit entered service through the ECRC (see the **Regulation** section).

As a result of the actions taken under the consent decree, emissions of all pollutant types have been significantly reduced. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM emissions from its facilities by 164,000 tons (94%), 63,000 tons (91%) and 4,500 tons (87%), respectively.

Reductions in mercury emissions also have occurred due to the repowering of the Gannon Power Station to the Bayside Power Station. At the Bayside Power Station, where mercury levels have decreased 99% below 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a system wide reduction of mercury emissions of more than 90% from 1998 levels.

Carbon Reductions and GHG

Tampa Electric has 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 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 to remain near 1990 levels until the addition of the next base load unit, which is scheduled to be in service in January 2017 (see the **Tampa Electric** and **Capital Expenditures** sections). Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same time frame, the numbers of retail customers and retail energy sales have risen by approximately 30% and 15%, respectively.

Tampa Electric's power plants currently emit approximately 16 million tons of CO_2 per year. Assuming a projected long-term average annual load growth of more than 1.0%, Tampa Electric could emit approximately 17 million tons of CO_2 (an increase of approximately 6%) by 2020 if natural gas-fired peaking and combined-cycle generation additions are used to meet customer demand.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but cannot predict whether the FPSC would grant such recovery. Tampa Electric's current solid-based energy generation is about 55% of its total system output in 2013, compared to being approximately 84% of its output in 2001. This is due to the conversion of the coal-fired Gannon Power Station into the natural gas-fired Bayside Power Station. However, solid fuel-fired facilities remain a significant component of Tampa Electric's diverse generation fleet and additional solid fuel units could be considered in the future.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a 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, 2013, TEC has estimated its ultimate financial liability to be $40.4 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other" on the Consolidated Balance Sheets. 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 portion of the cleanup costs attributable to Tampa Electric. The estimates to perform the work are based on Tampa Electric'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.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, Tampa Electric could be liable for more than Tampa Electric's actual percentage of the remediation costs.

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. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Capital Expenditures

Tampa Electric's 2013 capital expenditures included approximately $41 million primarily for upgrades to scrubbers and modifications to coal combustion by-product storage areas at the Big Bend Power Station. See the **Liquidity, Capital Expenditures** section of **MD&A** for information on estimated future capital expenditures related to environmental compliance.

PEOPLES GAS SYSTEM – Gas Operations

PGS operates as the gas division of TEC. PGS is engaged in the purchase, distribution and sale of natural gas for residential, commercial, industrial and electric power generation customers in the state of Florida.

Gas is delivered to the PGS system through three interstate pipelines. PGS does not engage in the exploration for or production of natural gas. PGS operates a natural gas distribution system that serves almost 350,000 customers. The system includes approximately 11,600 miles of mains and 6,700 miles of service lines (see PGS's **Franchises and Other Rights** section below).

PGS had 553 employees as of Dec. 31, 2013. A total of 148 employees in five of PGS's 14 operating divisions and call center are represented by various union organizations.

In 2013, the total throughput for PGS was almost 1.7 billion therms. Of this total throughput, 6% was gas purchased and resold to retail customers by PGS, 85% was third-party supplied gas that was delivered for retail transportation-only customers and 9% was gas sold off-system. Industrial and power generation customers consumed approximately 61% of PGS's annual therm volume, commercial customers consumed approximately 26%, off-system sales customers consumed 9% and the remaining balance was consumed by residential customers.

While the residential market represents only a small percentage of total therm volume, residential operations comprised about 33% of total revenues. Approximately 5% of revenues are attributed to governmental municipalities.

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. PGS has also seen increased interest and development in natural gas vehicles. There are 21 compressed natural gas filling stations connected to the PGS distribution system.

Revenues and therms for PGS for the years ended Dec. 31 were as follows:

	Revenues			***Therms***		
(millions)	*2013*	*2012*	*2011*	*2013*	*2012*	*2011*
Residential	$ 128.1	$ 125.4	$ 140.8	74.4	70.8	77.7
Commercial	133.4	134.1	138.0	438.1	421.4	409.3
Industrial	13.4	10.3	8.8	272.0	237.3	205.0
Off system sales	56.7	73.7	106.0	143.1	224.0	231.0
Power generation	9.9	12.4	10.6	744.4	913.5	614.3
Other revenues	42.2	34.9	39.9			
Total	$ 383.7	$ 390.8	$ 444.1	1,672.0	1,867.0	1,537.3

No significant part of PGS's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect on PGS. PGS's business is not highly seasonal, but winter peak throughputs are experienced due to colder temperatures.

Regulation

The operations of PGS are regulated by the FPSC separately from the regulation of Tampa Electric. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC seeks to set rates at a level that provides an opportunity for a utility such as PGS to collect total revenues (revenue requirements) equal to its cost of providing service, plus a reasonable return on invested capital.

The basic costs of providing natural gas service, other than the costs of purchased gas and interstate pipeline capacity, are recovered through base rates. Base rates are designed to recover the costs of owning, operating and maintaining the utility system. The rate of return on rate base, which is intended to approximate PGS's weighted cost of capital, primarily includes its cost for debt, deferred income taxes at a zero cost rate, and an allowed ROE. Base rates are determined in FPSC revenue requirements proceedings which occur at irregular intervals at the initiative of PGS, the FPSC or other parties. For a description of recent proceeding activity, see the **Regulation-PGS Rates** section of **MD&A**.

PGS's results reflect base rates established in May 2009, when the FPSC approved a base rate increase of $19.2 million which became effective on Jun. 18, 2009 and reflects an ROE of 10.75%, which is the middle of a range between 9.75% and 11.75%. The allowed equity in capital structure is 54.7% from all investor sources of capital, on an allowed rate base of $560.8 million.

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the PGA 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 delivers 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 calendar year 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 2013, the FPSC approved PGS's 2014 PGA cap factor for the period January 2014 through December 2014.

In addition to its base rates and PGA clause charges, PGS customers (except interruptible customers) also pay a per-therm charge for energy conservation and pipeline replacement programs. The conservation charge is intended to permit PGS to recover, on a dollar-for-dollar basis, prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are mandated by Florida law and approved and monitored by the FPSC. PGS is also permitted to earn a return, depreciation expenses and applicable taxes associated with the replacement of cast iron/bare steel infrastructure. PGS projects to have all cast iron and bare steel removed from its system within 10 years. Lastly, the FPSC requires natural gas utilities to offer transportation-only service to all non-residential customers.

In addition to economic regulation, PGS is subject to the FPSC's safety jurisdiction, pursuant to which the FPSC regulates the construction, operation and maintenance of PGS's distribution system. In general, the FPSC has implemented this by adopting the Minimum Federal Safety Standards and reporting requirements for pipeline facilities and transportation of gas prescribed by the U.S. Department of Transportation in Parts 191, 192 and 199, Title 49, Code of Federal Regulations.

PGS is also subject to federal, state and local environmental laws and regulations pertaining to air and water quality, land use, noise and aesthetics, solid waste and other environmental matters (see the **Environmental Matters** section).

Competition

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, propane and fuel oil. PGS has taken actions to retain and expand its commodity and transportation business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. PGS has a "NaturalChoice" program, offering unbundled transportation service to all non-residential customers, as well as residential customers consuming in excess of 1,999 therms annually, allowing these customers to purchase commodity gas from a third party but continue to pay PGS for the transportation. 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 20,500 transportation-only customers as of Dec. 31, 2013 out of approximately 35,000 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-only services at discounted rates.

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 FGT through 66 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's Jacksonville division receives gas delivered by the Southern Natural Gas pipeline through two gate stations located northwest of Jacksonville. Gulfstream Natural Gas Pipeline provides delivery through six gate stations. PGS also has one interconnection with its affiliate SeaCoast Gas Transmission, LLC in Clay County, Florida.

Companies with firm pipeline capacity receive priority in scheduling deliveries during times when the pipeline is operating at its maximum capacity. PGS presently holds sufficient firm capacity to permit it to meet the gas requirements of its system commodity customers, except during localized emergencies affecting the PGS distribution system and on abnormally cold days.

Firm transportation rights on an interstate pipeline represent a right to use the amount of the capacity reserved for transportation of gas on any given day. PGS pays reservation charges on the full amount of the reserved capacity whether or not it actually uses such capacity on any given day. When the capacity is actually used, PGS pays a volumetrically-based usage charge for the amount of the capacity actually used. The levels of the reservation and usage charges are regulated by the FERC. PGS actively markets any excess capacity available on a day-to-day basis to partially offset costs recovered through the PGA clause.

PGS procures natural gas supplies using base-load 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.

Neither PGS nor any of the interconnected interstate pipelines have storage facilities in Florida. PGS occasionally faces situations when the demands of all of its customers for the delivery of gas cannot be met. In these instances, it is necessary that PGS interrupt or curtail deliveries to its interruptible customers. In general, the largest of PGS's industrial customers are in the categories that are first curtailed in such situations. PGS's tariff and transportation agreements with these customers give PGS the right to divert these customers' gas to other higher priority users during the period of curtailment or interruption. PGS pays these customers for such gas at the price they paid their suppliers or at a published index price, and in either case pays the customer for charges incurred for interstate pipeline transportation to the PGS system.

Franchises and Other Rights

PGS holds franchise and other rights with 110 municipalities throughout Florida. These franchises govern the placement of PGS's facilities on the public rights-of-way as it carries on its retail business in the localities it serves. The franchises specify the negotiated terms and conditions governing PGS's use of public rights-of-way and other public property within the municipalities it serves during the term of the franchise agreement. The franchises are irrevocable and are not subject to amendment without the consent of PGS, although in certain events they are subject to forfeiture.

Municipalities are prohibited from granting any franchise for a term exceeding 30 years. Several franchises contain purchase options with respect to the purchase of PGS's property located in the franchise area, if the franchise is not renewed; otherwise, based on judicial precedent, PGS is able to keep its facilities in place subject to reasonable rules and regulations imposed by the municipalities.

PGS's franchise agreements with the incorporated municipalities within its service area have various expiration dates ranging from the present through 2043. PGS expects to negotiate nine franchises in 2014; five will be renewals of existing agreements and four will be new agreements. Franchise fees payable by PGS, which totaled $8.2 million at Dec. 31, 2013, are calculated using various formulas which are based principally on natural gas revenues. Franchise fees are collected from only those customers within each franchise area.

Utility operations in areas outside of incorporated municipalities are conducted in each case under one or more permits to use state or county rights-of-way granted by the Florida Department of Transportation or the county commission of such counties. There is no law limiting the time for which such permits may be granted by counties. There are no fixed expiration dates, and these rights are, therefore, considered perpetual.

Environmental Matters

PGS's operations are subject to federal, state and local statutes, rules and regulations relating to the discharge of materials into the environment and the protection of the environment that generally require monitoring, permitting and ongoing expenditures.

TEC is one of several PRPs for certain superfund sites and, through PGS, for former manufactured gas plant sites. See the previous discussion in the **Environmental Matters** section of **Tampa Electric – Electric Operations**.

Capital Expenditures

During the year-ended Dec. 31, 2013, PGS did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2014 through 2018 period.

TECO COAL

Overview

TECO Coal, with offices located in Corbin, Kentucky, is a wholly owned subsidiary of TECO Energy, Inc. and through its subsidiaries operates surface and underground mines as well as coal processing facilities in eastern Kentucky, Tennessee and southwestern Virginia.

TECO Coal owns no operating assets but holds all of the common stock of Gatliff Coal Company, Rich Mountain Coal Company, Clintwood Elkhorn Mining Company, Pike-Letcher Land Company, Premier Elkhorn Coal Company, Perry County Coal Corporation and Bear Branch Coal Company. TECO Coal owns, controls and operates, by lease or mineral rights, surface and underground mines and coal processing and loading facilities. TECO Coal produces, processes and sells bituminous, predominately low sulfur coal of metallurgical, PCI, steam and industrial grades.

TECO Coal is a supplier of metallurgical and PCI coal for use in the steel-making process and a supplier of thermal coal to electric utilities and manufacturing industries. TECO Coal also exports metallurgical and PCI coals internationally, primarily to European markets.

Metallurgical, PCI and industrial stoker coals accounted for approximately 54% of TECO Coal's 2013 coal sales volume. Thermal coal accounted for approximately 46% of 2013 coal sales volume.

As of Dec. 31, 2013, TECO Coal owned or leased mineral rights to approximately 298.2 million tons of proven and probable coal reserves. Of the total proven and probable reserves, approximately 80% are low sulfur reserves with high BTU content. Total proven and probable reserves are expected to support current production levels for more than 20 years.

The tons sold for 2013, 2012 and 2011 by market category is set forth in Table 1 below:

Coal Sales by Market Category
(Millions of Tons)
Table 1

	Metallurgical, PCI & Industrial Stoker		Thermal	
Year	**Tons**	**% Volume**	**Tons**	**% Volume**
2013	3.1	54%	2.7	46%
2012	2.7	44%	3.5	56%
2011	3.7	46%	4.4	54%

Sales of thermal coal during 2013, 2012 and 2011 were made primarily to utilities and industrial customers throughout the eastern part of the United States. Sales of metallurgical and PCI coal during those years were made primarily to steel companies and coke plants in North America and Europe.

TECO Coal currently operates 18 underground mines, which employ the room and pillar mining method, and seven surface mines.

In 2013, TECO Coal sold 5.8 million tons of coal. All of this coal was sold to customers other than the TECO Coal affiliate, Tampa Electric.

No significant part of TECO Coal's business is dependent upon a single or limited number of customers where the loss of any one or more would have a significant adverse effect, and the business is not highly seasonal.

History

In 1967, Cal-Glo Coal Company was formed. It mined a product containing low sulfur, low ash fusion characteristic and high energy content. Realizing the potential for this product to meet its combustion, quality, and environmental requirements, Tampa Electric purchased Cal-Glo Coal Company in 1974. In 1982, after several years of continued growth and success, TECO Coal Corporation was formed and Cal-Glo Coal Company was renamed as Gatliff Coal Company. Rich Mountain Coal Company was established in 1987, when leases were signed for properties in Campbell County, Tennessee.

In 1988, Gatliff Coal Company began selling coal to the ferro-silicon and silicon markets. Also in that year, properties were acquired in Pike County, Kentucky, and Clintwood Elkhorn Mining Company was formed. Premier Elkhorn Coal Company and Pike-Letcher Land Company were formed in 1991, when additional property was acquired in Pike and Letcher Counties, Kentucky.

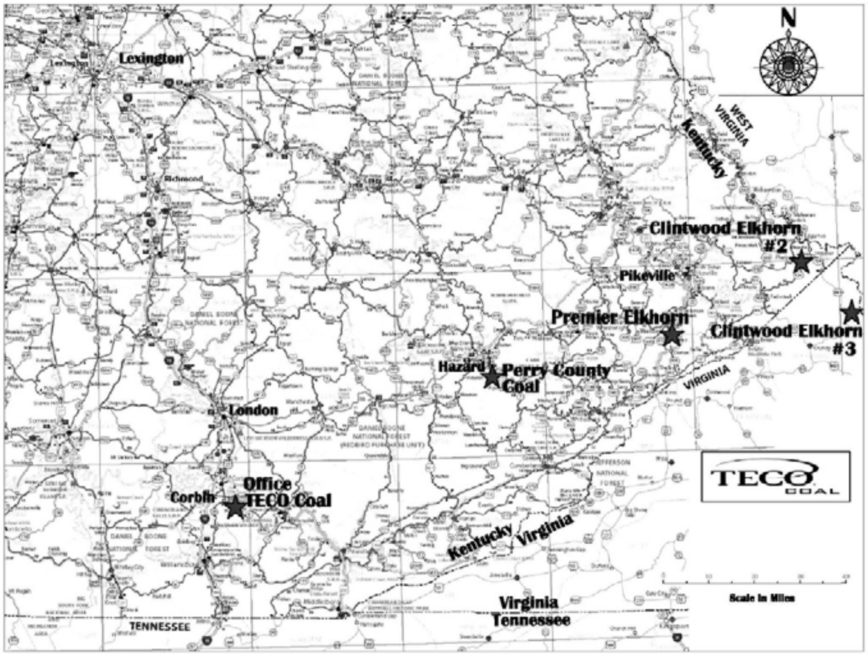
In 1997, Bear Branch Coal Company secured key leases for properties located in Perry County and Knott County, Kentucky.

In 2000, Perry County Coal Corporation was purchased. It is located in Perry, Knott and Leslie Counties, Kentucky.

Mining Operations

TECO Coal currently has four mining complexes, all operating in Kentucky, with a portion of Clintwood Elkhorn Mining Company operating in Virginia as well. A mining complex is defined as all mines that supply a single wash plant, except in the case of Clintwood Elkhorn Mining Company, which provides production for two active wash plants. These complexes blend, process and ship coal that is produced from one or more mines, with a single complex handling the coal production of as many as eleven individual underground or surface mines. TECO Coal uses two distinct extraction techniques: continuous underground mining and dozer and front-end loader surface mining, sometimes accompanied by highwall mining.

The complexes have been developed at locations in close proximity to the TECO Coal preparation plants and rail shipping facilities. Coal is transported from TECO Coal's mining complexes to customers by means of railroad cars, trucks, barges or vessels, with rail shipments representing approximately 89% of 2013 coal shipments. The following map shows the locations of the four mining complexes and TECO Coal's offices in Corbin, Kentucky.



Facilities

Coal mined by the operating companies of TECO Coal is processed and shipped from facilities located at each of the operating companies, with Clintwood Elkhorn Mining Company having two facilities. The equipment at each facility is in good condition and regularly maintained by qualified personnel. Table 2 below is a summary of TECO Coal processing facilities:

Processing Facilities Summary
Table 2

COMPANY	FACILITY	LOCATION	RAILROAD SERVICE	UTILITY SERVICE
Clintwood Elkhorn	Clintwood #2 Plant	Biggs, KY	Norfolk Southern	American Electric Power
Clintwood Elkhorn	Clintwood #3 Plant	Hurley, VA	Norfolk Southern	American Electric Power
Premier Elkhorn	Burke Branch Plant	Myra, KY	CSXT Railroad	American Electric Power
Perry County Coal	Davidson Branch Plant	Hazard, KY	CSXT Railroad	American Electric Power

Significant Projects

Significant projects for 2013 included the following:

Premier Elkhorn Coal

- Premier Elkhorn began the transition to highwall mining on three surface mines. This mining process is expected to lower the overall mining ratio for the surface mines, as well as allow us to emphasize the greater recovery of high quality specialty coal. The first highwall miner was in operation in July 2013, with the second and third expected to be in operation in February 2014 and early second quarter 2014, respectively.
- Premier Elkhorn continued evaluation of the recently discovered reserves of the New Frontier–Burke Branch Development project and continued permitting for the construction phases of the project for slope and shaft construction. Much of the identified reserves are owned by TECO Coal.

Mining Complexes

Table 3 below shows annual production for each mining complex for each of the last three years and 2013 coal sales.

MINING COMPLEXES
Table 3

Location	Mine Type	Mining Equipment	Transportation	Tons Produced (in Millions) 2013	2012	2011	Tons Sold (1) (in Millions) 2013	Year Established Or Acquired
Gatliff Coal Co.								
Bell County, KY/ Knox County, KY/ Campbell County, TN	S	D/L	T	0.0	0.0	0.0	0.0	1974
Clintwood Elkhorn Mining								
Pike County, KY/ Buchanan County, VA	U, S	CM, D/L, HM, A	R, R/V	1.6	2.0	1.8	1.7	1988
Premier Elkhorn Coal Co.								
Pike County, KY/ Letcher County, KY/ Floyd County, KY	U, S	CM, D/L	R, T, R/B, T/B, R/V	1.6	2.0	2.2	2.1	1991
Perry County Coal Co.								
Perry County, KY/ Leslie County, KY/ Knott County, KY	U, S	CM, D/L, HM	R, T, R/B, T/B, R/V	2.0	2.3	3.1	2.0	2000
			Totals:	**5.2**	**6.3**	**7.1**	**5.8**	

(1) Tons sold include both amounts produced by TECO Coal subsidiaries and a limited amount of purchased coal.

S – Surface
CM – Continuous Miner
U – Underground
D/L – Dozers and Front-End Loaders
HM – Highwall Miner
A - Auger
R – Rail
R/B – Rail to Barge
R/V – Rail to Ocean/Lake Vessel
T – Truck
T/B – Truck to Barge

Gatliff Coal

Gatliff Coal Company discontinued surface mine operations in Bell County, Kentucky in late autumn 2009. Poor market conditions and a depletion of the low sulfur content coal that was previously required on its sales contract led to this cessation of mining operations. Gatliff Coal had no production in 2011, 2012 or 2013, leaving a reserve base of 3.4 million recoverable tons of predominantly low sulfur underground mineable coal, which may later be recovered by Gatliff Coal or by neighboring competing coal companies for coal royalty considerations. Rich Mountain Coal Company formerly operated as a contractor for Gatliff Coal's Tennessee production but is currently in non-producing reclamation status.

Clintwood Elkhorn Mining

Clintwood Elkhorn Mining Company has two coal preparation facilities. One is located near Biggs, Kentucky in Pike County, and is supplied by ten underground mines. Facilities include a 125 car unit train load-out capable of loading 4,000 tons per hour. The second Clintwood Elkhorn Mining facility is located near Hurley, Virginia and is supplied by one underground mine and two surface mines. Some mines have supplied both locations during the course of the year. The second facility also includes a 100 car unit train load-out capable of loading 650 tons per hour. Principal products at both locations include High Volatile metallurgical coal and thermal coal. Products from both locations are shipped domestically to customers in North America via Norfolk Southern Corporation and vessels via the Great Lakes. International customers receive their products via ocean vessels from Lamberts Point, Virginia. CMMA completed a baseline audit for Clintwood Elkhorn for the year ended 2013. CMMA has estimated by audit methodology that there are 55.2 million recoverable tons of demonstrated coal reserves, as of Dec. 31, 2013. Of the demonstrated reserves, an estimated 46.5 million recoverable tons, or 84%, are of proven (measured) status and 8.7 million tons, or 16%, are of probable (indicated) status. All of the reserves are leased. By market category, the demonstrated reserves are: 49.5 million tons of metallurgical coal and 5.7 million tons of thermal coal. In total, Clintwood Elkhorn Mining produced 1.6 million tons of coal in 2013 and currently has a reserve base of 55.2 million recoverable tons.

Premier Elkhorn Coal Company

Located near Myra, in Pike County, Kentucky, Premier Elkhorn Coal Company is supplied by production from four underground mines and three surface mines. Principal products include metallurgical and PCI coal for the steel mills, high-quality thermal coal for utilities and specialty stoker products for ferro-silicon and industrial customers. Facilities include a unit train load-out with a 200 car siding capable of loading at 6,000 tons per hour. Products from this location are shipped via CSXT Railroad and trucking contractors to destinations in North America and internationally. In total, Premier Elkhorn Coal produced 1.6 million tons of coal in 2013 and currently has a reserve base of 103.9 million recoverable tons.

In 2011, CMMA completed an audit of the Glamorgan and Lower Banner coal deposits associated with the New Frontier Project-Burke Branch Development, which is controlled by TECO Coal's Premier Elkhorn Coal operating subsidiary. The subject property is located in Pike and Letcher Counties in eastern Kentucky, and a substantial portion of the mineral rights for the subject coal deposits is owned by TECO Coal's subsidiary, Pike-Letcher Land. The remainder of the mineral is leased from other entities under long-term lease agreements.

The CMMA audit reviewed the classification of the TECO Coal tons by proven and probable reserves and non-reserve coal deposit (resource) categories, based on a pro-forma economic review of the demonstrated reserve areas. TECO Coal estimates that it controls 65.0 million recoverable tons of demonstrated coal reserves within the Burke Branch Development, as of Aug. 31, 2011. Of these TECO Coal total demonstrated reserves, an estimated 56.6 million recoverable tons, or 87%, are owned and 8.4 million tons, or 13%, are leased. An additional 23.4 million tons have been estimated by TECO Coal and classified as non-reserve coal deposits (resources). These resource tons have some potential to be reclassified as reserve in the future depending on various factors such as favorable results of additional exploration, property acquisition, investment of capital for project development, improvements in coal markets or mining technology.

TECO Coal has received an amendment to an existing permit to allow surface excavation and development as well as slope access to a portion of these reserves and a revision to an existing permit to allow mining of a portion of the Lower Banner coal seam reserves. An additional amendment has been submitted to modify surface areas required for development of the slopes and shafts.

Perry County Coal Corporation

Located in Perry County, Kentucky, near Hazard, Perry County Coal Corporation is supplied by production from three underground mines and two surface mines. Principal products include PCI, high quality thermal coal for utilities, and industrial stoker products. Facilities include a 1,350 ton per hour preparation plant and a 120 car unit train load-out capable of loading 5,000 tons per hour. Products from this location are shipped via CSXT Railroad and trucking contractors.

Perry County Coal produced 2.0 million tons of coal in 2013, leaving a total reserve base of 135.7 million recoverable tons.

Sales and Marketing

The TECO Coal marketing and sales force includes sales directors, distribution/transportation managers and administrative personnel. Primary customers are steel companies, utilities and industrial plants. TECO Coal sells coal under long-term agreements, which are generally classified as greater than 12 months, and on a spot basis, which is generally classified as 12 months or less.

The terms of these coal sales contracts result from bidding and negotiations with customers. Consequently, these contracts typically vary significantly in price, quantity, quality, length, and may contain terms and conditions that allow for periodic price reviews, price adjustment mechanisms, recovery of governmental impositions as well as provisions for force majeure, suspension, termination, treatment of environmental legislation and assignment.

Current sales are made to both domestic and European markets, and the metallurgical coal from the Burke Branch Development is expected to be marketed to new markets and customers in Europe, South America and Asia.

Distribution

TECO Coal transports coal from its mining complexes to customers by rail, barge, vessel and trucks. The company employs transportation specialists who coordinate the development of acceptable shipping schedules with our customers, transportation providers and mining facilities.

Competition

Primary competitors of TECO Coal are other coal suppliers, many of which are located in Central Appalachia. Even though consolidation and bankruptcy have decreased the number of coal suppliers, the industry is still intensely competitive. To date, TECO Coal has been able to compete for coal sales by mining specialty coals, including coals used for making coke and furnace injection, and high-quality thermal coal and by effectively managing production and processing costs.

Employees

As of Dec. 31, 2013, TECO Coal and its subsidiaries employed a total of 754 employees.

Regulations

Mine Safety and Health

The operations of underground mines, including all related surface facilities, are subject to the Federal Coal Mine Safety and Health Act of 1969, the 1977 Amendment and the Miner Act of 2006. TECO Coal's subsidiaries are also subject to various Kentucky, Tennessee and Virginia mining laws which require approval of roof control, ventilation, dust control and other facets of the coal mining business. Federal and state inspectors inspect the mines to ensure compliance with these laws. TECO Coal believes it is in substantial compliance with the standards of the various enforcement agencies. It is unaware of any mining laws or regulations that would materially affect the market price of coal sold by its subsidiaries, although mining accidents within the industry could lead to new legislation that could impose additional costs on TECO Coal.

Black Lung Legislation

Under the Black Lung Benefits Revenue Act of 1977 and the Black Lung Benefits Reform Act of 1977, as amended in 1981, each coal mine operator must make payment of federal black lung benefits to claimants who are current and former employees, certain survivors of a miner who dies from black lung disease, and to a trust fund for the payment of benefits and medical expenses to claimants who last worked in the coal industry prior to July 1973. Historically, a small percentage of the miners currently seeking federal black lung benefits are awarded these benefits by the federal government. The trust fund is funded by an excise tax on coal production of up to $1.10 per ton for deep-mined coal and up to $0.55 per ton for surface-mined coal, neither amount to exceed 4.4% of the gross sales price.

In December 2000, the Department of Labor issued amendments to the regulations implementing the federal black lung laws that, among other things, establish a presumption in favor of a claimant's treating physician, limit a coal operator's ability to introduce medical evidence, and redefine Coal Workers Pneumoconiosis to include chronic obstructive pulmonary disease. These changes in the regulations, and regulations introduced by the 2010 Patient Protection and Affordable Care Act, have slightly increased the percentage of claims approved and the overall cost of Black Lung to coal operators. While costs have risen only slightly from these changes, there is potential for additional, higher increases in the future. TECO Coal, with the help of its consulting actuaries, intends to continue monitoring claims very closely.

Workers' Compensation

TECO Coal is liable for workers' compensation benefits for traumatic injury and occupational exposure claims under state workers' compensation laws. Workers' compensation laws are administered by state agencies with each state having its own set of rules and regulations regarding compensation that is owed to an employee that is injured in the course of employment.

Environmental Laws

Surface Mining Control and Reclamation Act

Coal mining operations are subject to the Surface Mining Control and Reclamation Act of 1977 which places a charge of $0.135 and $0.315 on every net ton of underground and surface coal mined, respectively, to create a fund for reclaiming land and water adversely affected by past coal mining. Other provisions establish standards for the control of environmental effects and reclamation of surface coal mining and the surface effects of underground coal mining and requirements for federal and state inspections.

Clean Air Act/Clean Water Act

While conducting their mining operations, TECO Coal's subsidiaries are subject to various federal, state and local air and water pollution standards. In 2013, TECO Coal had expenditures of approximately $2.6 million for environmental protection and reclamation programs. TECO Coal expects to spend approximately $2.2 million on these programs in 2014.

CERCLA (Superfund)

The CERCLA – commonly known as Superfund, affects coal mining and hard rock operations by creating liability for investigation and remediation in response to releases of hazardous substances into the environment and for damages to natural resources. Under Superfund, joint and several liabilities may be imposed on waste generators, site owners or operators and others regardless of fault.

Under the EPA's Toxic Release Inventory process, companies are required to report annually listed toxic materials that exceed defined quantities.

Glossary of Selected Mining Terms

Assigned reserves. Coal which has been committed by the coal company to operating mine shafts, mining equipment, and plant facilities, and all coal which has been leased by the company to others.

Bituminous Coal. The most common type of coal with moisture content less than 20% by weight and heating value of 10,500 to 14,000 BTU per pound. It is dense and often has well-defined bands of bright and dull material.

BTU (British Thermal Unit). A measure of the energy required to raise the temperature of one pound of water one degree Fahrenheit.

Central Appalachia. Coal producing regions of eastern Kentucky, eastern Tennessee, western Virginia and southern West Virginia.

Coal seam. Coal deposits occur in layers. Each layer is called a "seam."

Coal washing. The process of removing impurities, such as ash and sulfur based compounds, from coal.

Compliance coal. Coal which, when burned, emits 1.2 pounds or less of sulfur dioxide per million BTUs, which is equivalent to 0.72% sulfur per pound of 12,000 BTU coal. Compliance coal requires no mixing with other coals or use of sulfur dioxide reduction technologies by generators of electricity to comply with the requirements of the federal Clean Air Act.

Continuous miner. A machine used in underground mining to cut coal from the seam and load it onto conveyors or into shuttle cars in a continuous operation.

Continuous mining. One of two major underground mining methods now used in the United States. This process utilizes a continuous miner. The continuous miner removes or "cuts" the coal from the seam. The loosened coal then falls onto a conveyor for removal to a shuttle car or larger conveyor belt system.

Deep mine. An underground coal mine.

Dozer and Front-end loader mining. An open-cast method of mining that uses large dozers together with trucks and loaders to remove overburden, which is used to backfill pits after coal removal.

Ferro-silicon. An alloy of iron and silicon used in the production of carbon steel.

Force Majeure. An event that may prevent the company from conducting its mining operations in whole or in part as a result of: Acts of God, wars, riots, fires, explosions, breakdowns or accidents; strikes, lockouts or other labor difficulties; lack or shortages of labor, materials, utilities, energy sources; compliance with governmental rules, regulations or other governmental requirements; or any other like causes.

High Vol Metallurgical coal. Coal that averages approximately 35% volatile matter. Volatile matter refers to a constituent that becomes gaseous when heated to certain temperatures.

Highwall miner. An auger-like apparatus that drives parallel rectangular entries from the surface up to 1,000 feet deep.

Industrial coal. Coal used by industrial steam boilers to produce electricity or process steam. It generally is lower in BTU heat content and higher in volatile matter than metallurgical coal.

Long-term contracts. Contracts with terms greater than 12 months.

Low ash fusion. Coal that when burned typically produces ash that has a melting point below 2,450 degrees Fahrenheit.

Low sulfur coal. Coal that when burned emits 1.6 pounds or less of sulfur dioxide per million BTUs.

Metallurgical coal. The various grades of coal suitable for carbonization to make coke for steel manufacture. Also known as “met” coal, it possesses four important qualities: volatility, which affects coke yield; the level of impurities, which affects coke quality, composition, which affects coke strength; and basic characteristics, which affect coke oven safety. Metallurgical coal has a particularly high BTU, but low ash content.

Overburden. Layers of earth and rock covering a coal seam. In surface mining operations, overburden is removed prior to coal extraction.

Overburden ratio. The amount of overburden commonly stated in cubic yards that must be removed to excavate one ton of coal.

Pillar. An area of coal left to support the overlying strata in a mine, sometimes left permanently to support surface structures.

Pneumoconiosis. A lung disease caused by long-continued inhalation of mineral or metallic dust.

Preparation plant. Usually located on a mine site, although one plant may serve several mines. A preparation plant is a facility for crushing, sizing and washing coal to prepare it for use by a particular customer. The washing process has the added benefit of removing some of the coal’s sulfur content.

Probable (Indicated) reserves. Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but the sites for inspection, sampling and measurement are farther apart; therefore, the degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

Proven (Measured) reserves. Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, workings or drill holes; grade and/or quality are computed from the results of detailed sampling and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well established.

Pulverized Coal Injection (PCI). A system whereby coal is pulverized and injected into blast furnaces in the production of steel and/or steel products.

Reclamation. The process of restoring land and the environment to their approximate original state following mining activities. The process commonly includes “recontouring” or reshaping the land to its approximate original appearance, restoring topsoil and planting native grass and ground covers. Reclamation operations are usually underway before the mining of a particular site is completed. Reclamation is closely regulated by both state and federal law.

Recoverable reserves. The amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods and under current law.

Reserves. That part of a mineral deposit that could be economically and legally extracted or produced at the time of the reserve determination.

Resource (non-reserve coal deposit). A coal-bearing body that does not qualify as a commercially viable coal reserve. Resources may be classified as such by either limited property control, geologic limitations, insufficient exploration or other limitations. In the future, it is possible that portions of the resource could be re-classified as reserve if those limitations are removed or mitigated by: improving market conditions, additional property control, favorable results of exploration, advances in technology, etc.

Roof. The stratum of rock or other mineral above a coal seam; the overhead surface of a coal working place. Same as "top."

Room and pillar mining. In the underground room and pillar method of mining, continuous mining machines cut three to nine entries into the coal bed and connect them by driving crosscuts, leaving a series of rectangular pillars or columns of coal to help support the mine roof and control the flow of air. As mining advances, a grid-like pattern of entries and pillars is formed. Additional coal may be recovered from the pillars as this panel of coal is retreated.

Spot market. Sales of coal under an agreement for shipments over a period of one year or less.

Thermal coal. Coal used by power plants and industrial steam boilers to produce electricity or process steam. It generally is lower in BTU heat content and higher in volatile matter than metallurgical coal.

Sulfur. One of the elements present in varying quantities in coal that contributes to environmental degradation when coal is burned. Sulfur dioxide is produced as a gaseous by-product of coal combustion.

Sulfur content. Coal is commonly described by its sulfur content due to the importance of sulfur in environmental regulations. "Low sulfur" coal has a variety of definitions but is typically used to describe coal consisting of 1.0% or less sulfur. A majority of TECO Coal's Central Appalachian reserves are of low sulfur grades.

Surface mine. A mine in which the coal lies near the surface and can be extracted by removing overburden.

Tipple. A structure that facilitates the loading of coal into rail cars.

Tons. A "short" or net ton is equal to 2,000 pounds. A "long" or British ton is 2,240 pounds; a "metric" tonne is approximately 2,205 pounds. The short ton is the unit of measure referred to in this Form 10-K.

Unassigned reserves. Coal that has not been committed and that would require new mineshafts, mining equipment or plant facilities before operations could begin in the property.

Underground mine. Also known as a "deep" mine. Usually located several hundred feet below the earth's surface, an underground mine's coal is removed mechanically and transferred by shuttle car or conveyor to the surface.

Unit train. A train of a specified number of cars carrying only coal. A typical unit train can carry at least 10,000 tons of coal in a single shipment.

Utility coal. Coal used by power plants to produce electricity or process steam. It generally is lower in BTU heat content and higher in volatile matter than metallurgical coal.

TECO GUATEMALA

TECO Guatemala, a wholly-owned subsidiary of TECO Energy, had subsidiaries with interests in independent power projects in Guatemala, which were sold during 2012.

TECO Guatemala indirectly owned 100% of CGESJ, the owner of an electric generating station located in Guatemala, which consisted of a single-unit pulverized-coal baseload facility (the San José Power Station). This facility was the first coal-fueled plant in Central America and meets environmental standards set by Guatemala and the World Bank. In 1996, CGESJ signed a U.S. dollar-denominated PPA with EEGSA, the largest private distribution company in Central America, to provide 120 MW of capacity and energy for 15 years beginning in 2000. TEMSA, an indirect wholly-owned subsidiary, provided unloading services to third parties in addition to receiving the coal shipments for CGESJ.

TCAE, an entity 96.06% owned by TPS Guatemala One, Ltd., an indirect subsidiary of TECO Guatemala, and the owner of an oil-fired electric generating facility (the Alborada Power Station), had a U.S. dollar-denominated PPA with EEGSA to provide 78 MW of capacity ending in 2015. EEGSA was responsible for providing the fuel for the power station, with a subsidiary of TECO Guatemala providing assistance in fuel administration.

TECO Guatemala's plants in Guatemala operated under environmental permits issued by the local environmental authorities. At the time of construction, these facilities were built in compliance with the World Bank Guidelines of 1988 and 1994.

On Sept. 27, 2012, TECO Guatemala entered into an agreement to sell all of the equity interests in the Alborada and San José power stations, related facilities and operations in Guatemala for a total purchase price of $227.5 million in cash. The sale of the

Alborada Power Station closed on the same date for a selling price of $12.5 million.

On Dec. 19, 2012, the closing occurred on the (i) San José power station and related facilities in Guatemala for a purchase price of $213.5 million and (ii) the remaining TECO Guatemala operations company for a purchase price of $1.5 million.

See **Notes 19, 20** and **21** to the **TECO Energy, Inc. Consolidated Financial Statements** for more information regarding these discontinued operations and asset dispositions.

On Dec. 19, 2013, the ICSID tribunal hearing TGH's arbitration claim against the Republic of Guatemala under DR-CAFTA issued an award in the case. The ICSID tribunal unanimously found in favor of TGH and awarded damages of approximately U.S. $21.1 million, plus interest from Oct. 21, 2010 at a rate equal to the prime rate plus 2%. In addition, the tribunal ruled that Guatemala must reimburse TGH for approximately $7.5 million of the costs it incurred in pursuing the arbitration.

The ICSID tribunal found that Guatemala breached its treaty obligation to grant TGH fair and equitable treatment under the terms of the DR-CAFTA, thereby causing damages to TGH for which it is entitled to compensation. In sum, the tribunal found that Guatemala's repudiation of fundamental regulatory principles applying to the tariff review process was arbitrary and breached elementary standards of due process in administrative matters.

Each party has 120 days from the date of the award to seek annulment of the decision.

EXECUTIVE OFFICERS OF THE REGISTRANT

The names, ages, current positions and principal occupations during the last five years of the current executive officers of TECO Energy are described below.

Name	Age	Current Positions and Principal Occupations During The Last Five Years
John B. Ramil	58	President and Chief Executive Officer, TECO Energy, Inc., and Chief Executive Officer, Tampa Electric Company, August 2010 to date; President and Chief Operating Officer, TECO Energy, Inc., July 2004 to August 2010.
Charles A. Attal, III	54	Senior Vice President-General Counsel and Chief Legal Officer, TECO Energy, Inc., and General Counsel of Tampa Electric Company, February 2009 to date; Vice President General Counsel and Chief Legal Officer, TECO Energy, Inc. and General Counsel of Tampa Electric Company, July 2007 to February 2009.
Phil L. Barringer	60	Senior Vice President of Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., January 30, 2013 to date; Vice President of Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., January 1, 2013 to January 30, 2013; Chief Human Resources Officer and Procurement Officer of Tampa Electric Company, January 2013 to date; Vice President-Human Resources of TECO Energy, Inc. and Tampa Electric Company, July 2009 to December 2012; President, TECO Guatemala, July 2009 to date (operating companies sold December 2012); and prior thereto, Vice President-Controller, Operations of TECO Energy, Inc. and Chief Accounting Officer of Tampa Electric Company.
Deirdre A. Brown	53	Senior Vice President of Corporate Strategy and Technology and Chief Ethics and Compliance Officer, TECO Energy, Inc., January 30, 2013 to date; Vice President of Business Strategy, Technology and Compliance and Chief Ethics and Compliance Officer, TECO Energy, Inc., January 1, 2013 to January 30, 2013; Vice President-Business Strategy and Compliance and Chief Ethics and Compliance Officer, TECO Energy, Inc., July 2009 to January 1, 2013; Vice President-Regulatory Affairs of Tampa Electric Company and Vice President-Customer Service, Tampa Electric Division of Tampa Electric Company, April 2006 to July 2009.
Sandra W. Callahan	61	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TECO Energy, Inc., February 2011 to date, and Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), Tampa Electric Company, October 2009 to date; Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TECO Energy, Inc., October 2009 to February 2011; Vice President-Finance and Accounting and Chief Financial Officer (Treasurer and Chief Accounting Officer), TECO Energy, Inc. and Tampa Electric Company, July 2009 to October 2009; Vice President-Treasury and Risk Management (Treasurer and Chief Accounting Officer), TECO Energy, Inc., January 2007 to July 2009; Vice President-Treasurer and Assistant Secretary, Tampa Electric Company, April 2005 to July 2009.
Gordon L. Gillette	54	President, Tampa Electric Company, July 2009 to date; Executive Vice President and Chief Financial Officer, TECO Energy, Inc., July 2004 to July 2009; President, TECO Guatemala, October 2004 to July 2009.
Clark Taylor	64	President of TECO Coal Corporation, April 2011 to date; and prior thereto, Vice President-Controller of TECO Coal Corporation.

There is no family relationship between any of the persons named above or between executive officers and any director of the company. The term of office of each officer extends to the meeting of the Board of Directors following the next annual meeting of shareholders, scheduled to be held on April 30, 2014, and until such officer’s successor is elected and qualified.

Item 1A. RISK FACTORS.

General Business and Operational Risks

General economic conditions may adversely affect our businesses.

Our businesses are affected by general economic conditions. In particular, growth in Tampa Electric's service area and Florida is important to the realization of annual energy sales growth for Tampa Electric and PGS. Any weakening of economic conditions, including the Florida housing markets and general economy, could adversely affect Tampa Electric's or PGS's expected performance and their ability to collect payments from customers.

TECO Coal is also affected by general economic conditions affecting primarily the utility and steel industries, both nationally and internationally. TECO Coal sells metallurgical coal domestically and internationally, including to European customers, and demand in that continent has been reduced due to the European debt crisis and the resulting economic weakness. Continued economic weakness and the resulting lower demand for metallurgical coal in the European and Asian markets could reduce TECO Coal's financial results.

Our electric and gas utilities are highly regulated; changes in regulation or the regulatory environment could reduce 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's financial performance by, for example, reducing revenues, increasing competition or costs, threatening investment recovery or impacting rate structure.

If Tampa Electric or PGS earn returns on equity above their respective allowed ranges, the earnings could be subject to review by the FPSC which could result in refunds to customers or changes in allowed returns on equity, which could reduce earnings and cash flow.

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.

Proposed new regulations on the disposal and/or storage of CCRs could add to Tampa Electric's operating costs.

In response to a coal ash pond failure in December 2008 at another utility, the EPA proposed new regulations for the management and disposal of CCRs. These proposed rules include two potential approaches. One approach, known as Subtitle C, would categorize CCRs destined for disposal as hazardous wastes. This proposal could be the most significant for Tampa Electric because management and disposal of hazardous wastes is extremely expensive, and waste landfills are currently prohibited in Florida by state law. In addition, the hazardous designation could require improvements to Tampa Electric's current ash management practices and interim storage and handling facilities for CCRs inside its power stations, even though permanent onsite disposal would not be allowed. The other proposed rule would set minimum standards for the final disposal of CCRs under regulations similar to those in place for municipal non-hazardous solid waste. This proposal would not be as disruptive as the former, since it would allow for the continued operation of ash impoundments on Tampa Electric's facilities. However it is unclear whether this approach would place additional management requirements on these existing disposal units or cause them to need structural improvements. The EPA's current schedule would result in a final proposed rule in 2015, although expected litigation would likely delay the rule's effective date.

Federal or state regulation of GHG emissions, depending on how they are enacted, could increase our costs or the rates charged to our customers, which could curtail sales.

Among our companies, Tampa Electric has the most significant number of stationary sources with air emissions. While GHG emission regulations have been proposed, both at the federal and state level, none has been passed at this time and, therefore, costs to reduce GHGs 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. New rules requiring post-combustion CO_2 removal could require significant investment in what is essentially experimental technology, costly conversion to natural gas fuel, or a premature shut-down of the units, which would result in non-cash write-offs.

Current 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 GHG emission regulation. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but we cannot be assured that the FPSC would grant such recovery.

In a June 25, 2013 memorandum to the EPA, President Obama directed that agency to issue new emissions standards for future power plants as well as modified, reconstructed or existing power plants to reduce GHG emissions. The new standards for future power plants were released in the fall of 2013, which essentially mandate that no new coal fired power plants will be constructed in the U.S. The new standards for existing power plants are due in June 2014. It is unclear how the EPA may design such rules. It is likely that both rules will be subject to legal challenges and litigation, which could have a material impact on both the timing and substance of any proposed new rules.

In the case of TECO Coal, the use of coal to generate electricity is considered a significant source of GHG 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.

Among other rules, the EPA has proposed a number of new rules, including the CAIR/CSAPR and Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT) for emissions to the air, and a number of new rules focused on water use and discharges from power generation facilities.

Together these air focused rules impose stringent reductions in several pollutants from electric utility steam generators, primarily coal-fired, but including oil-fired as well. If the CSAPR rule is implemented as planned, the EPA has estimated that the implementation of CSAPR would require significant investment in pollution-control equipment for units not already equipped or could result in the retirement of primarily smaller, older coal-fired power stations that do not currently have state-of-the-art air pollution-control equipment already installed. The retirement of these units or switching to other fuels for compliance with this rule is likely to reduce overall demand for coal, which could reduce sales and financial results at TECO Coal.

The EPA's proposed water focused rules could limit the supply of water available to our power generating facilities, require the investment of significant capital for new equipment and increase operating costs.

A mandatory RPS could add to Tampa Electric's costs and adversely affect its operating results.

In past sessions of the Florida Legislature, an RPS was debated but ultimately not enacted, but an RPS standard could be enacted in the future. In addition, there is the potential that legislation could be proposed in the U.S. Congress to introduce an RPS at the federal level. It remains unclear, however, if or when action on such legislation would be completed. Tampa Electric could incur significant costs to comply with an RPS. Tampa Electric's operating results could be adversely affected if Tampa Electric were not permitted to recover these costs from customers through the ECRC.

Tampa Electric, the state of Florida and the nation as a whole are increasingly dependent on natural gas to generate electricity. There may not be adequate infrastructure to deliver adequate quantities of natural gas to meet the expected future demand, and the expected higher demand for natural gas may lead to increasing costs for the commodity.

In Florida and across the United States, utilities are increasingly relying on natural gas for new electric generating plants in response to GHG emissions concerns and attractive natural gas prices. Currently, there is an adequate supply and infrastructure to meet demand for natural gas in Florida and nationally. However, if future supplies are inadequate or if significant new investment is required to install the pipelines necessary to transport the gas, the cost of natural gas could rise. Currently, Tampa Electric and PGS are allowed to pass the cost for the commodity gas and transportation services to customers without profit. Changes in regulations could reduce earnings if they required Tampa Electric or PGS to bear a portion of the increased cost. In addition, increased costs to customers could result in lower sales.

Our businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations.

All of our businesses are affected by variations in general weather conditions and unusually severe weather. Tampa Electric's and PGS's 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. If climate change or other factors cause significant variations from normal weather, this could have a material impact on energy sales.

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 negatively impact results at Tampa Electric and PGS.

Variations in weather conditions also affect the demand and prices for the commodities sold by TECO Coal. Severe weather conditions could interrupt or slow coal production or rail transportation and increase operating costs.

The state of Florida is exposed to extreme weather, including hurricanes, which can cause damage to our facilities and affect our ability to serve customers.

As a company with electric service and natural gas operations in peninsular Florida, the company is exposed to extreme weather events, such as hurricanes. Extreme weather conditions can be destructive, causing outages and property damage that require the company to incur additional expenses. Extensive customer outages could reduce revenue collections. If warmer temperatures lead to changes in extreme weather events (increased frequency, duration and severity), these expenses could be greater.

While the company has storm preparation and recovery plans in place, and Tampa Electric and PGS have historically been granted regulatory approval to recover or defer the majority of significant storm costs incurred, extreme weather still poses risks to our operations and storm cost-recovery petitions may not always be granted or may not be granted in a timely manner. If costs associated with future severe weather events cannot be recovered in a timely manner, or in an amount sufficient to cover actual costs, our financial condition and operating results could be adversely affected.

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

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

Competition among coal producers in Central Appalachia and other producing regions, and low natural gas prices may adversely affect TECO Coal's ability to sell steam coal. Low-cost natural gas has allowed utility steam coal users to switch from coal to natural gas to produce electricity, which has reduced the current market price and demand for TECO Coal's steam coal from domestic utilities. Continued low natural gas prices and increased competition from lower cost producing areas would keep demand and selling prices low, which would reduce TECO Coal's profitability, or reduce the value of its reserves.

TECO Coal has historically sold about 50% of its production to domestic utilities for use in the generation of power. For over three years, natural gas prices have been dramatically lower than previous averages due to the growth of hydraulic fracturing in the production of natural gas from shale formations. These low natural gas prices have caused utility coal users to switch to lower cost natural gas to generate electricity. Even with a modest increase in natural gas prices as occurred in the second half of 2013, it remains more cost effective for users of higher cost Central Appalachian coal, which TECO Coal produces, to burn a higher percentage of natural gas for power generation. Lower cost coals from other producing regions of the U.S., such as the Powder River Basin and the Illinois Basin are being utilized by more utilities in lieu of higher cost Central Appalachian coals, further reducing demand.

At the end of 2013, more than 50% of TECO Coal's profitable steam coal contracts expired and current market prices for Central Appalachian steam coal are not profitable. Without an increase in the cost of natural gas and an increase in the use of coal for power generation, or a general improvement in coal market conditions, TECO Coal's profitability will be reduced. If these conditions were to persist, the value of TECO Coal's reserves could be reduced, which could result in a non-cash impairment charge.

Results at our utility companies may be affected by changes in customer energy-usage patterns, and the cost of complying with potential new environmental regulations.

For the past several years, weather-normalized energy consumption per residential customer declined due to the combined effects of voluntary conservation efforts, economic conditions, improvements in lighting and appliance efficiency, trends toward smaller single family houses and increased multi-family housing.

The utilities' forecasts are based on normal weather patterns and historical trends in customer energy-usage patterns. Tampa Electric's and PGS's ability to increase energy sales and earnings could be negatively impacted if customers continue to use less energy in response to increased energy efficiency of lights and appliances, economic conditions or other factors.

Compliance with proposed GHG emissions reductions, a mandatory RPS or other new regulation could raise Tampa Electric's cost. While current regulation allows Tampa Electric to recover the cost of new environmental regulation through the ECRC, increased costs for electricity may cause customers to change usage patterns, which would impact Tampa Electric's sales.

Our computer systems and Tampa Electric's infrastructure may be subject to cyber (primarily electronic or internet-based) or physical attacks, which could disrupt operations, cause loss of important data or compromise customer, employee-related or other critical information or systems.

There have been an increasing number of cyber-attacks on companies around the world, which have caused operational failures or compromised sensitive corporate or customer data. These attacks have occurred over the Internet, through malware, viruses, or attachments to e-mails or through persons inside of the organization or through persons with access to systems inside of the organization.

We have security systems and infrastructure in place that are designed to prevent such attacks, and these systems are subject to internal, external and regulatory audits to ensure adequacy. Despite these efforts, we cannot be assured that a cyber-attack will not cause electric or gas system operational problems, disruptions of service to customers, compromise important data or systems, or subject us to additional regulation, litigation or damage to our reputation.

There have also been physical attacks on critical infrastructure at other utilities. While Tampa Electric's transmission and distribution system infrastructure is designed and operated in such a manner to mitigate the impact of this type of attack, in the event of a physical attack that disrupts service to customers, revenues would be reduced and costs would be incurred to repair any damage. These types of events, either impacting our facilities or the industry in general, could also cause us to incur additional security- and insurance-related costs, and could have adverse effects on our business and financial results and condition.

We rely on some transmission and distribution assets that we do not own or control to deliver wholesale electricity, and 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.

The value of our existing deferred tax benefits are determined by existing tax laws, and could be negatively impacted by changes in these laws.

"Comprehensive tax reform" remains a topic of discussion in the U.S. congress. Such legislation could significantly alter the existing tax code, including a reduction in corporate income tax rates. Although a reduction in the corporate income tax rate could result in lower future tax expense and tax payments, it would reduce the value of our existing deferred tax asset and could result in a charge to earnings from the write-down of that asset, and reduce future cash flow at the parent company.

The current administration in Washington D.C. has proposed the elimination of the percentage depletion tax deduction for the mining of coal, and other hard minerals and fossil fuels.

If the percentage depletion tax deduction is eliminated for TECO Coal, the effective tax rate for that company would rise from the historical 20% to 25% to the general corporate tax rate of 37%, which would reduce earnings from TECO Coal.

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

We evaluate our long-lived assets 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 non-cash 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, equipment failures and operations below expected levels of performance or efficiency. Our subsidiaries could incur problems such as the breakdown or failure of power generation equipment, transmission lines, pipelines, coal mining or processing equipment or other equipment or processes that would result in performance below assumed levels of output or efficiency. The occurrence of one or more of these problems could cause us to incur substantial costs, including potential claims for damages that may exceed the scope of our insurance coverage, which could have an adverse impact on our financial condition and results from operations.

Failure to obtain the permits necessary to open new surface mines could reduce earnings from TECO Coal.

Our surface coal mining operations are dependent on permits from the USACE to open new surface mines necessary to maintain or increase production. Since 2008, new permits issued by the USACE under Section 404 of the Clean Water Act for new surface coal mining operations have been challenged in court by various environmental groups, resulting in very few usable permits being issued. Failure to obtain the necessary permits to open new surface mines, which are required to maintain and expand production, could reduce production, cause higher mining costs or require purchasing coal at prices above our cost of production to fulfill contract requirements, which would reduce the earnings expected from TECO Coal.

In 2010, the EPA issued new guidelines related to water quality for Central Appalachian coal surface mining operations that would be conditions of new surface mine permits, which would add significant cost to operations or curtail our surface mining activities and preparation plant operations.

In 2010, the EPA issued new guidance on environmental permitting requirements for Central Appalachian mountaintop removal and other surface mining projects. The guidance limits conductivity (level of mineral salts) in water discharges into streams from permitted areas, and was effective immediately on an interim basis. In 2011, the EPA made this guidance final. Because the EPA's standards appear to be unachievable under most circumstances, surface mining activity could be substantially curtailed since most new and pending permits would likely be rejected. This guidance could also be extended to discharges from deep mines and preparation plants, which could result in a substantial curtailing of those activities as well. In 2012, the United States District Court for the District of Columbia ruled that the EPA had exceeded its statutory authority in establishing the water quality guidance discussed above in the manner in which it was done. Following the outcome of this court decision, pending appeals by the EPA, few, if any, new usable permits have been issued by the USACE. Over time, if new permits are not issued, TECO Coal could incur higher production costs or reduced production from surface mining operations.

TECO Coal's sales to international customers are subject to risks that could result in losses or increased costs.

TECO Coal is exposed to financial risk through its sales to international customers in Europe and Asia. TECO Coal attempts to mitigate this risk through the use of third parties to broker the sales, dollar-denominated contracts, passage of title upon loading in the U.S. port, customer responsibility for the international freight, letters of credit posted by customers for purchase price of the commodity and the transportation to the U.S. port, and the utilization of local agents where appropriate. TECO Coal cannot be assured that these measures will effectively mitigate all international risks, which could have an adverse effect on TECO Coal's financial conditions.

In 2014, TECO Coal has a higher percentage of its metallurgical coal sales committed to customers in Asia than in recent years. Prices for metallurgical coal sales to Asia are subject to being reset on a quarterly basis based on supply and demand in the region. Over the past two years the quarterly prices have been lower due to increased supply from Australia and other suppliers and weakening demand for metallurgical coal from China. Lower quarterly prices could reduce TECO Coal's profitability below levels forecast for 2014.

Increased customer use of distributed generation could adversely affect our regulated electric utility business.

In many areas of the country there is growing use of rooftop solar panels, small wind turbines and other small scale methods of power generation, called distributed generation, by individual residential, commercial and industrial customers. Distributed generation is encouraged and supported by various special interest groups, tax incentives, renewable portfolio standards and special rates designed to support such generation.

Increased usage of distributed generation, particularly in those states where solar or wind resources are the most abundant, is reducing utility electricity sales but not reducing the need for ongoing investment in infrastructure to maintain or expand the transmission and distribution grid to reliably serve customers. Continued utility investment not supported by increased energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

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

There is competition in wholesale power sales across the country. 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 expected performance.

The gas distribution industry has been subject to competitive forces for several years. Gas services provided by PGS are 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's results. However, future structural changes that we cannot predict could adversely affect PGS.

From time to time, we are a party to legal proceedings that may result in a material adverse effect on our financial condition.

From time to time, we are a party to, or otherwise involved in, lawsuits, claims, proceedings, investigations and other legal matters that have arisen in the ordinary course of conducting our business. While the outcome of these lawsuits, claims, proceedings, investigations and other legal matters which we are a party to, or otherwise involved in, cannot be predicted with certainty, an adverse outcome could result in a material adverse effect on our financial condition.

Risks Associated With the Acquisition of New Mexico Gas Company

The acquisition of NMGI may not be completed or regulatory approval may be subject to unfavorable conditions, and if completed, changing market conditions, associated costs and other factors prior to, or following, the acquisition, could adversely affect the anticipated benefits of the transaction and the company's results.

On May 25, 2013, the company entered into a stock purchase agreement to acquire the common stock of NMGI, the parent company of NMGC. In order to complete this transaction, the company must obtain approval from the NMPRC. The NMPRC may not approve the transaction, or may impose terms or conditions on the approval which could delay the completion of the transaction, impose additional costs, or otherwise impact the anticipated benefits of the transaction. In addition, the anticipated benefits of the transaction are based on estimates of transaction and integration-related costs, which are dependent on financial market conditions and other factors, which may materially change. Negative changes in these factors could have an adverse effect on the anticipated benefits of the transaction or the company's business, financial condition, results of operations or stock price.

In order to finance the New Mexico Gas acquisition, we plan to incur additional indebtedness and issue equity securities, which could have an adverse effect on our financial health.

We currently expect to finance the New Mexico Gas acquisition with a combination of TECO Energy common equity, cash on hand and long-term debt at NMGC and NMGI. Incurrence of additional debt may have an adverse effect on our financial condition and may limit our ability to obtain financing in the future. Furthermore, the issuance of equity securities will result in additional shares outstanding and may have an adverse effect on the market price of our common stock.

Additionally, if we fail to realize the expected benefits from the NMGC acquisition or if the financial performance of NMGC does not meet our current expectations, it may have a negative effect on our financial profile. If we cannot obtain the permanent financing we expect, alternative financing under the Bridge Facility would be on less favorable financial terms. In that event, any debt incurred to replace or refinance the amounts under the Bridge Facility could also be under less favorable terms.

The closing of the NMGC acquisition may be delayed, which would delay the realization of accretion to our earnings from the acquisition.

As previously disclosed, TECO Energy must obtain approval for the acquisition from the NMPRC prior to closing the transaction. On Dec. 2, 2013, the Hearing Examiner, in the application for approval of the acquisition, issued an order approving the motion filed by TECO Energy, Inc., NMGC, Continental Energy Systems LLC, the Staff of the NMPRC, and the New Mexico Attorney General's Office (the "Parties") requesting additional time for proceedings in the matter.

On Jan. 10, 2014, a meeting was held with the Parties and the Hearing Examiner to establish a new schedule. The new key dates established in that meeting are: Staff and intervenor testimony due on or before Feb. 28, 2014, hearings before the Hearing Examiner to follow on March 24 to 28, 2014. The date for a final decision is yet to be determined. With this schedule, closing will likely occur in the third quarter of 2014.

At the time of the acquisition announcement in May 2013, based on certain schedule assumptions, TECO Energy had indicated that with a closing in the first quarter of 2014, it expected the transaction to be accretive to earnings in the first full year post-closing in 2015. With the new projected schedule and less time to achieve full integration in 2014, the transaction is now expected to begin to be accretive to earnings twelve months after closing.

Profitability at NMGC is heavily dependent upon the sale of energy for residential heating. Warmer-than-normal weather conditions, the effects of global warming and climate change, or other factors that influence customer energy usage may affect NMGC's energy sales and adversely impact its financial position.

NMGC's earnings are primarily generated by the sale of natural gas for residential heating. Significantly warmer-than-normal weather conditions, or other factors such as global warming or climate change may results in reduced natural gas sales and lower profitability.

In connection with the acquisition of NMGC, we expect to record additional goodwill and long-lived assets that could become impaired and adversely impact our financial condition and results from operations.

We assess long-lived assets and goodwill for impairment annually or more frequently if events or circumstances occur that would more likely than not reduce the fair value of those assets below their carrying values. To the extent the value of goodwill or a long-lived asset becomes impaired, we may be required to record non-cash impairment charges that could have a material impact on results from operations.

Financing Risks

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

We have substantial indebtedness, which has resulted in 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.

TECO Energy, TECO Finance and TEC must meet certain financial tests as defined in the applicable agreements to use their respective credit facilities. Also, TECO Energy, TECO Finance, TEC and other operating companies have certain restrictive covenants in specific agreements and debt instruments. See the **Credit Facilities** section and **Significant Financial Covenants** table in the **Liquidity, Capital Resources** sections of the **Management's Discussion & Analysis** for descriptions of these tests and covenants.

As of Dec. 31, 2013, we were in compliance with required financial covenants, but we cannot be assured 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 the **Liquidity, Capital Resources** sections of the **Management's Discussion & Analysis**.

Financial market conditions could limit our access to capital and increase our costs of borrowing or refinancing, or have other adverse effects on our results.

The financial market conditions that were experienced in 2008 and early 2009 impacted access to both the short- and long-term capital markets and the cost of such capital. TECO Finance has debt maturing in 2015 of which it expects to refinance a portion. Future financial market conditions could limit our ability to raise the capital we need and could increase our interest costs, which could reduce earnings.

We enter into derivative transactions, primarily with financial institutions as counterparties. Financial market turmoil could lead to a sudden decline in credit quality among these counterparties, which could make in-the-money positions uncollectable.

We enter into derivative transactions with counterparties, most of which are financial institutions, to hedge our exposure to commodity price changes. Although we believe we have appropriate credit policies in place to manage the non-performance risk associated with these transactions, turmoil in the financial markets could lead to a sudden decline in credit quality among these counterparties. If such a decline occurs for a counterparty with which we have an in-the-money position, we could be unable to collect from such counterparty.

Declines in the financial markets or in interest rates used to determine benefit obligations could increase our pension expense or the required cash contributions to maintain required levels of funding for our plan.

Under calculation requirements of the Pension Protection Act, as of the Jan. 1, 2014 measurement date, the funded percentage of our plan is expected to be approximately 98%. TECO Energy estimates its contributions to range from $5 million to $50 million annually over the next five years. Any future declines in the financial markets or further declines in interest rates could increase the amount of contributions required to fund our plan in the future.

We estimate that pension expense in 2014 will be lower than in 2013, primarily due to the higher interest rates and pension plan asset growth in 2013. Any future declines in the financial markets or decreases in interest rates, however could, cause pension expense to increase in future years.

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

We are forecasting capital expenditures at Tampa Electric to support the current levels of customer growth, to comply with the design changes mandated by the FPSC to harden transmission and distribution facilities against hurricane damage, to maintain transmission and distribution system reliability, to maintain coal-fired generating unit reliability and efficiency, and to add generating capacity at the Polk Power Station.

If our capital expenditures exceed 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 could be adversely affected.

Our financial condition and ability to access capital may be materially adversely affected by multiple ratings downgrades to below investment grade, and we cannot be assured of any rating improvements in the future.

Our senior unsecured debt is rated as investment grade by S&P at BBB, by Moody's Investor's Services (Moody's) at Baa1, and by Fitch Ratings (Fitch) at BBB. The senior unsecured debt of TEC is rated by S&P at BBB+, by Moody's at A2 and by Fitch at A- . A downgrade to below investment grade by the rating agencies, which would require a two-notch downgrade by S&P and Fitch, and a three notch downgrade by Moody's, 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 may also 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 any such downgrades. In addition, downgrades could adversely affect our relationships with customers and counterparties.

At current ratings, Tampa Electric and PGS are able to purchase electricity and gas without providing collateral. If the ratings of TEC decline to below investment grade, Tampa Electric and PGS could be required to post collateral to support their purchases of electricity and gas.

We are a holding company with no business operations of our own and depend on cash flow from our subsidiaries to meet our obligations.

We are a holding company with no business operations of our own or material assets other than the stock of our subsidiaries. Accordingly, all of our operations are conducted by our subsidiaries. As a holding company, we require dividends and other payments from our subsidiaries to meet our cash requirements. If our subsidiaries are unable to pay us dividends or make other cash payments to us, we may be unable to pay dividends or satisfy our obligations.

Item 1B. UNRESOLVED STAFF COMMENTS.

None.

Item 2. PROPERTIES.

TECO Energy believes that the physical properties of its operating companies are adequate to carry on their businesses as currently conducted. The properties of Tampa Electric are subject to a first mortgage bond indenture under which no bonds are currently outstanding.

TAMPA ELECTRIC

Tampa Electric has three electric generating stations in service, with a December 2013 net winter generating capability of 4,668 MW. Tampa Electric assets include the Big Bend Power Station (1,572 MW capacity from four coal units and 61 MW from a CT), the Bayside Power Station (1,839 MW capacity from two natural gas combined cycle units and 244 MW from four CTs) and the Polk Power Station (220 MW capacity from the IGCC unit and 732 MW from four CTs).

The Big Bend coal fired units went into service from 1970 to 1985 and the CT was installed in 2009. The Polk IGCC unit began commercial operation in 1996. Bayside Unit 1 was completed in April 2003, Unit 2 was completed in January 2004 and Units 3 through 6 were completed in 2009. In 2009, Tampa Electric placed the Phillips Power Station on long-term reserve standby. In July of 2012, Tampa Electric placed the City of Tampa Partnership Station in long-term reserve standby.

Tampa Electric owns 180 substations having an aggregate transformer capacity of 22,330 Mega Volts Amps. The transmission system consists of approximately 1,310 pole miles (including underground and double-circuit) of high voltage transmission lines, and the distribution system consists of 6,292 pole miles of overhead lines and 4,851 trench miles of underground lines. As of Dec. 31, 2013, there were 671,381 meters in service. All of this property is located in Florida.

All plants and important fixed assets are held in fee except that titles to some of the properties are subject to easements, leases, contracts, covenants and similar encumbrances and minor defects of a nature common to properties of the size and character of those of Tampa Electric.

Tampa Electric has easements or other property rights for rights-of-way adequate for the maintenance and operation of its electrical transmission and distribution lines that are not constructed upon public highways, roads and streets. It has the power of eminent domain under Florida law for the acquisition of any such rights-of-way for the operation of transmission and distribution lines. Transmission and distribution lines located in public ways are maintained under franchises or permits.

TEC has a long-term lease for the office building in downtown Tampa which serves as headquarters for TECO Energy, Tampa Electric and PGS.

PEOPLES GAS SYSTEM

PGS's distribution system extends throughout the areas it serves in Florida and consists of approximately 18,300 miles of pipe, including approximately 11,600 miles of mains and 6,700 miles of service lines. Mains and service lines are maintained under rights-of-way, franchises or permits.

PGS's operations are located in 14 operating divisions throughout Florida. While most of the operations and administrative facilities are owned, a small number are leased.

TECO COAL

Property Control

Operations of TECO Coal and its subsidiaries are conducted on both owned and leased properties totaling approximately 294,000 acres in Kentucky, Tennessee and Virginia. TECO Coal's current practice is to obtain a title review from a licensed attorney prior to purchasing or leasing property. As is typical in the coal mining industry, TECO Coal generally has not obtained title insurance in connection with its acquisitions of coal reserves and/or related surface properties. In many cases, the seller or lessor will grant the purchasing or leasing entity a warranty of property title. When leasing coal reserves and/or related surface properties where mining has previously occurred, TECO Coal may opt not to perform a separate title confirmation due to the previous mining activities on such a property. In cases involving less significant properties and consistent with industry practices, title and boundaries to less significant properties are now verified during lease or purchase negotiations.

In situations where property is controlled by lease, the lease terms are generally sufficient to allow the reserves for the associated operation to be mined within the initial lease term. The terms of many of these leases extend until the exhaustion of the mineable and merchantable coal from the leased property. If, however, extensions of the original lease term become necessary, provisions have generally been made within the original lease to extend the lease term upon continued payment of minimum royalties.

Coal Reserves

As of Dec. 31, 2013, the TECO Coal operating companies had a combined estimated 298.2 million tons of proven and probable recoverable reserves. All of the reserves consist of high quality bituminous coal. Reserves are the portion of the proven and probable tonnage that meet TECO Coal's economic criteria regarding mining height, preparation plant recovery, depth of overburden and stripping ratio. Generally, these reserves would be commercially mineable at year-end price and cost levels. Additionally, other controlled areas presently identified as resource total 69.6 million tons of coal.

Reserves are defined by SEC Industry Guide 7 as that part of a mineral deposit which could be economically and legally extracted or produced at the time of the reserve determination. Proven and probable coal reserves are defined by SEC Industry Guide 7 as follows:

Proven (Measured) Reserves - Reserves for which (a) quantity is computed from dimensions revealed in outcrops, trenches, working or drill holes: grade and/or quality are computed from the results of detailed sampling; and (b) the sites for inspection, sampling and measurement are spaced so closely and the geologic character is so well defined that size, shape, depth and mineral content of reserves are well-established.

Probable (Indicated) Reserves - Reserves for which quantity and grade and/or quality are computed from information similar to that used for proven reserves, but for which the sites for inspection, sampling and measurement are farther apart or are otherwise less adequately spaced. The degree of assurance, although lower than that for proven reserves, is high enough to assume continuity between points of observation.

Drill hole spacing for confidence levels in reserve calculations is based on guidelines in U.S. Geological Survey Circular 891 (Coal Resource Classification System of the U.S. Geological Survey). In this method of classification, “proven” reserves are considered to be those lying within one-quarter mile (1,320 feet) of a valid point of measurement and “probable” reserves are those lying between one-quarter mile and three-quarters mile (3,960 feet) from such an observation point.

Reserve estimates are prepared by TECO Coal’s staff of geologists. There are two chief geologists with the responsibility to track changes in reserve estimates, supervise TECO Coal’s other geologists and coordinate third party reviews of reserve estimates by qualified mining consultants. Annually, a third-party reserve audit is performed by CMMA on TECO Coal’s newly identified reserves. The results of that audit are reflected in the numbers within this report.

The following table (Table 4) shows recoverable reserves by quantity and the method of property control as well as the Assigned and Unassigned reserves per mining complex.

RECOVERABLE RESERVES BY QUANTITY[(1)]
(Millions of tons)
Table 4

							Assigned[(2)]		Unassigned[(2)]	
Mining Complex	Location	Total	Proven	Probable	Owned	Leased	2014	2013	2014	2013
Gatliff Coal	Bell County, KY/ Knox County, KY/ Campbell County, TN	3.4	3.0	0.4	1.2	2.2	0.5	0.5	2.9	2.9
Clintwood Elkhorn Mining	Pike County, KY/ Buchanan County, VA	55.2	46.5	8.7	0.0	55.2	55.2	60.8	0.0	0.0
Premier Elkhorn Coal	Pike County, KY/Letcher County, KY/ Floyd County, KY	103.9	63.4	40.5	85.0	18.9	52.9	58.6	51.0	51.0
Perry County Coal	Perry County, KY/ Leslie County, KY/ Knott County, KY	135.7	87.5	48.2	1.4	134.3	130.5	131.9	5.2	5.2
Totals:		**298.2**	**200.4**	**97.8**	**87.6**	**210.6**	**239.1**	**251.8**	**59.1**	**59.1**

Notes:

(1) Recoverable reserves represent the amount of proven and probable reserves that can actually be recovered from the reserve base taking into account all mining and preparation losses involved in producing a saleable product using existing methods under current law. Reserve information reflects a moisture of 6.5%. This moisture factor represents the average moisture present in TECO Coal’s delivered coal.

(2) Assigned reserves means coal which has been committed by TECO Coal to operating mine shafts, mining equipment, and plant facilities, and all coal which has been leased by TECO Coal to others. Unassigned reserves represent coal which has not been committed, and which would require new mineshafts, mining equipment, or plant facilities before operations could begin in the property.

RECOVERABLE RESERVES BY QUALITY[1]
(Millions of tons)
Table 5

Mining Complex	Recoverable Reserves	Sulfur Content < 1%[2]	Sulfur Content >1%[2]	Compliance Tons[3]	Average BTU As received	Coal Type[4]
Gatliff Coal	3.4	3.2	0.2	0.0	12,000-13,100	LSU
Clintwood Elkhorn Mining	55.2	41.4	13.8	14.8	12,500-13,500	HVM, LSU, PCI
Premier Elkhorn Coal	103.9	88.5	15.4	57.0	12,700-13,100	HVM, IS, LSU, PCI
Perry County Coal	135.7	106.0	29.7	82.8	12,500-13,100	LSU, PCI, V
Totals:	**298.2**	**239.1**	**59.1**	**154.6**		

Notes:
(1) Reserve information reflects a moisture factor of 6.5%. This moisture factor represents the average moisture present in TECO Coal's delivered coal.
(2) <1% or >1% refers to sulfur content as a percentage in coal by weight.
(3) Compliance coal is any coal that emits less than 1.2 pounds of sulfur dioxide per million BTU when burned. Compliance coal meets sulfur emission standards imposed by Title IV of the Clean Air Act.
(4) Reserve holdings include metallurgical, PCI and thermal coal reserves. Although metallurgical and PCI coal reserves receive the highest selling price in the current market when marketed to steel-making customers, they can also be marketed as an ultra-high BTU, low sulfur utility coal for electricity generation.

HVM – High Vol Metallurgical
PCI – Pulverized Coal Injection
LSU – Low Sulfur Utility
V – Various
IS – Industrial Stoker

Market Allocation of Reserves

The table below shows the allocation of TECO Coal reserves by market category (metallurgical, PCI, and thermal coal), which was prepared by TECO Coal at its four operating subsidiaries. As shown below, a substantial portion of the Clintwood Elkhorn Mining coal reserves has been allocated to the metallurgical category (with the remainder to the thermal coal category), a substantial portion of the Premier Elkhorn Coal reserves has been allocated to the PCI and metallurgical categories (with the remainder to the thermal coal category), a substantial portion of the Perry County coal reserves has been allocated to the PCI category (with the remainder to the thermal coal category), and all of the Gatliff Coal reserves has been allocated to the thermal coal category.

At TECO Coal's request, CMMA completed an audit of the methodology used by TECO Coal to conduct such allocation of its coal tonnage estimates. CMMA reviewed information provided by TECO Coal and TECO Coal's methodology of processing, which included examination by certified professional geologists of all supplied coal deposit maps and supporting coal quality data using industry-accepted standards. The audit performed by CMMA concluded that TECO Coal's methodology of allocating its demonstrated reserves by market category is reasonably and responsibly prepared in accordance with industry accepted standards and in general conformance with SEC Industry Guide 7.

Market conditions may not always permit sales of coal into the particular market as identified, however the objective of this reserve allocation is to recognize the market potential for planning and investment purposes.

The following table (Table 6) shows the recoverable reserves by market category per mining complex and in total. The total reserve mix is defined by percentage as 40% metallurgical, 40.6% PCI, (for a combined 80.6% specialty coals) and 19.4% thermal coal.

RESERVES BY MARKET CATEGORY
Table 6

Mining Complex	Met Reserves			PCI Reserves			Thermal Reserves			Grand Totals
	Proven	Probable	Total	Proven	Probable	Total	Proven	Probable	Total	
Gatliff Coal	0.0	0.0	0.0	0.0	0.0	0.0	2.8	0.6	3.4	3.4
Clintwood Elkhorn Mining	41.4	8.1	49.5	0.0	0.0	0.0	0.0	5.7	5.7	55.2
Premier Elkhorn Coal	33.4	36.0	69.4	13.2	2.0	15.2	16.8	2.5	19.3	103.9
Perry County Coal	0.0	0.0	0.0	67.5	38.5	106.0	19.9	9.8	29.7	135.7
Totals:	**74.8**	**44.1**	**118.9**	**80.7**	**40.5**	**121.2**	**39.5**	**18.6**	**58.1**	**298.2**
% of Totals:			**39.9%**			**40.6%**			**19.5%**	

Reserve Estimation Procedure

TECO Coal’s reserves are based on over 3,800 data points, including drill holes, prospect measurements and mine measurements. Reserve estimates also include information obtained from on-going exploration drilling and in-mine channel sampling programs. Reserve classification is determined by evaluation of engineering and geologic information along with economic analysis. These reserves are adjusted periodically to reflect fluctuations in the economics in the market and/or changes in engineering parameters and/or geologic conditions. Additionally, the information is constantly being updated to reflect new data for existing property as well as new acquisitions and depleted reserves.

This data may include elevation, thickness, and where samples are available, the quality of the coal from individual drill holes and channel samples. The information is assembled by geologists and engineers at TECO Coal, and is computer modeled from which preliminary reserve estimations are generated. The information derived from the geological database is then combined with data on ownership or control of the mineral and surface interests to determine the extent of the reserves in a given area. Determinations of reserves are made after in-house geologists have reviewed the computer generated models and enhanced the grid models to better reflect regional trends.

During TECO Coal’s reserve evaluation and mine planning, TECO Coal takes into account factors such as restrictions under railroads, roads, buildings, power lines, or other structures. Depending on these factors, coal recovery may be limited or, in some instances, entirely prohibited. Current engineering practices are used to determine potential subsidence zones. The footprint of the relevant structure, as well as a safety angle-of-draw, is considered when mining near or under such facilities. Also, as part of TECO Coal’s reserve and mineability evaluation, TECO Coal reviews legal, economic and other technical factors. Final review and recoverable reserve determination is completed after a thorough analysis by in-house engineers, geologists and finance associates.

Item 3. LEGAL PROCEEDINGS.

From time to time, TECO Energy and its subsidiaries are involved in various 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 accounting standards 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.

For a discussion of certain legal proceedings and environmental matters, including an update of previously disclosed legal proceedings and environmental matters, see **Notes 12** and **9**, **Commitments and Contingencies**, of the **TECO Energy** and **Tampa Electric Company Consolidated Financial Statements**, respectively.

Item 4. MINE SAFETY DISCLOSURES.

TECO Coal is subject to regulation by the MSHA under the Federal Mine Safety and Health Act of 1977 (the Mine Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act) and the adopted Item 104 of Regulation S-K (17 CFR 229.104) is included in **Exhibit 95** to this annual report.

PART II

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

The following table shows the high and low sale prices for shares of TECO Energy common stock, which is listed on the New York Stock Exchange, and dividends paid per share, per quarter.

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
2013				
High	$ 17.87	$ 19.22	$ 17.99	$ 17.75
Low	16.71	16.40	16.15	16.40
Close	17.82	17.19	16.54	17.24
Dividend	$ 0.22	$ 0.22	$ 0.22	$ 0.22
2012				
High	$ 19.41	$ 18.33	$ 18.64	$ 18.14
Low	17.35	16.90	17.26	16.12
Close	17.55	18.06	17.74	16.76
Dividend	$ 0.22	$ 0.22	$ 0.22	$ 0.22

The approximate number of shareholders of record of common stock of TECO Energy as of Feb. 14, 2014 was 11,476.

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 to its common shareholders are dividends and other distributions from its operating companies.

See **Liquidity, Capital Resources – Covenants in Financing Agreements** section of **MD&A**, and **Notes 6, 7** and **12** to the **TECO Energy Consolidated Financial Statements** for additional information regarding significant financial covenants.

All of TEC's common stock is owned by TECO Energy and, therefore, there is no market for the stock. TEC pays dividends on its common stock substantially equal to its net income. Such dividends totaled $222.1 million in 2013, $228.3 million in 2012 and $240.7 million in 2011. See the **Restrictions on Dividend Payments and Transfer of Assets** section in **Note 1** to the **Tampa Electric Company Consolidated Financial Statements** for a description of restrictions on dividends on its common stock.

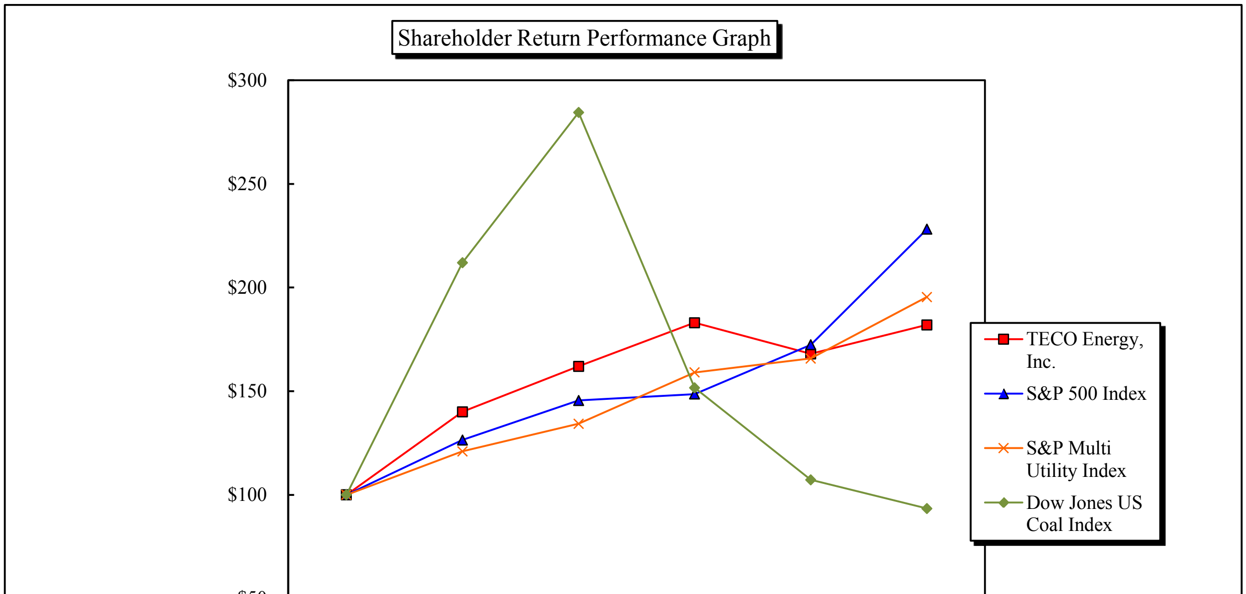
Set forth below is a table showing shares of TECO Energy common stock deemed repurchased by the issuer.

	Total Number of Shares (or Units) Purchased (1)	Average Price Paid per Share (or Unit)	Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs
Oct. 1, 2013 – Oct. 31, 2013	771	$16.95	0.0	0.0
Nov. 1, 2013 – Nov. 30, 2013	6,957	$17.06	0.0	0.0
Dec. 1, 2013 – Dec. 31, 2013	469	$16.96	0.0	0.0
Total 4th Quarter 2013	8,197	$17.04	0.0	0.0

(1) These shares were not repurchased through a publicly announced plan or program, but rather relate to compensation or retirement plans of the company. Specifically, these shares represent shares delivered in satisfaction of the exercise price and/or tax withholding obligations by holders of stock options who exercised options (granted under TECO Energy's incentive compensation plans), shares delivered or withheld (under the terms of grants under TECO Energy's incentive compensation plans) to offset tax withholding obligations associated with the vesting of restricted shares and shares purchased by the TECO Energy Group Retirement Savings Plan pursuant to directions from plan participants or dividend reinvestment.

Shareholder Return Performance Graph

The following graph shows the cumulative total shareholder return on TECO Energy's common stock on a yearly basis over the five-year period ended Dec. 31, 2013, and compares this return with that of the S&P 500 Index, the S&P Multi Utility Index and the Dow Jones U.S. Coal Index. The graph assumes that the value of the investment in TECO Energy's common stock and each index was $100 on Dec. 31, 2008 and that all dividends were reinvested.



	2008	2009	2010	2011	2012	2013
TECO Energy, Inc.	$100	$140	$162	$183	$168	$182
S&P 500 Index	$100	$126	$146	$149	$172	$228
S&P Multi Utility Index	$100	$121	$134	$159	$166	$195
Dow Jones US Coal Index	$100	$212	$285	$152	$107	$93

Item 6. SELECTED FINANCIAL DATA OF TECO ENERGY, INC.

(millions, except per share amounts) *Years ended Dec. 31,*	*2013*	*2012*	*2011*	*2010*	*2009*
Revenues [1]	$ 2,851.3	$ 2,996.6	$ 3,209.9	$ 3,363.5	$ 3,302.2
Net income from continuing operations [1]	197.8	246.0	250.8	211.6	182.4
Net income from discontinued operations attributable to TECO Energy [1]	(0.1)	(33.3)	21.8	27.4	31.5
Net income attributable to TECO Energy	197.7	212.7	272.6	239.0	213.9
Total assets	7,448.0	7,334.9	7,307.2	7,270.9	7,219.5
Long-term debt, including current portion	2,921.1	2,972.7	3,073.4	3,226.4	3,309.5
EPS - Basic					
From continuing operations [1]	$ 0.92	$ 1.14	$ 1.17	$ 0.99	$ 0.85
From discontinued operations attributable to TECO Energy [1]	0.00	(0.15)	0.10	0.13	0.15
Attributable to TECO Energy	$ 0.92	$ 0.99	$ 1.27	$ 1.12	$ 1.00
EPS - Diluted					
From continuing operations [1]	$ 0.92	$ 1.14	$ 1.17	$ 0.98	$ 0.85
From discontinued operations attributable to TECO Energy [1]	0.00	(0.15)	0.10	0.13	0.15
Attributable to TECO Energy	$ 0.92	$ 0.99	$ 1.27	$ 1.11	$ 1.00
Dividends paid per common share outstanding	$ 0.880	$ 0.880	$ 0.850	$ 0.815	$ 0.800

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 19** to the **TECO Energy Consolidated Financial Statements.**

Item 7.

MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITIONS & RESULTS OF OPERATIONS

This Management's Discussion & 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 as of the date we filed this report, and we do not undertake to update or revise such forward-looking statements, except as may be required by law. These forward-looking statements include references to our anticipated capital expenditures, liquidity and financing requirements, projected operating results, future environmental matters, and regulatory 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 & 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 an energy-related holding company with regulated electric and gas utility operations in Florida, Tampa Electric and PGS, respectively. In May 2013, we signed an agreement to acquire the largest regulated gas distribution utility in New Mexico which, upon closing would increase our regulated customer base by approximately 50%. Our only remaining unregulated business is TECO Coal, which owns and operates coal production facilities in the Central Appalachian coal production region.

Our regulated utilities, Tampa Electric and PGS, operate in the Florida market. Tampa Electric serves almost 695,000 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 4,668 MW. PGS, Florida's largest gas distribution utility, serves approximately 347,000 residential, commercial, industrial and electric power generating customers in all major metropolitan areas of the state, with a total natural gas throughput of almost 1.7 billion therms in 2013.

Our unregulated business, TECO Coal, through its subsidiaries operates surface and underground mines and related coal-processing facilities in eastern Kentucky, southwestern Virginia and Tennessee, producing metallurgical-grade and high-quality steam coals. Sales in 2013 were 5.8 million tons.

In 2012, we sold our ownership interest in TECO Guatemala, which through its subsidiaries, owned a coal-fired generating facility and a 96% ownership interest in an oil-fired peaking power generating plant, both in Guatemala.

PENDING ACQUISITION OF NMGI

In May 2013, we announced the signing of an agreement to acquire the regulated natural gas distribution utility NMGC for $950 million including the assumption of $200 million of existing NMGC debt, subject to customary closing adjustments. Under the terms of the agreement, TECO Energy will acquire NMGI, the owner of NMGC. The transaction is subject to approval by the NMPRC. The federal approval process, a Hart-Scott-Rodino antitrust review, was completed without comment in 2013. The transaction is expected to be accretive to earnings beginning 12 months after closing.

NMGC serves approximately 509,000, primarily residential, customers throughout New Mexico. Upon closing of the transaction, TECO Energy subsidiaries will serve more than 1.5 million regulated electric and gas utility customers in Florida and New Mexico. NMGC has approximately 740 employees, and the majority of its customers are located in the Central Rio Grande Corridor region, which is one of the fastest growing regions in the state. The company serves approximately 60 percent of the state's population with customers in 23 of New Mexico's 33 counties. Customers are served through a combination of approximately 1,600 miles of transmission pipeline and 10,000 miles of distribution lines.

The transaction is supported by a fully committed bridge financing facility. The permanent financing is expected to be a combination of $350 to $400 million of TECO Energy common equity, cash on hand and approximately $250 million of long-term debt at NMGI and NMGC.

As discussed above, the acquisition is subject to approval by the NMPRC. In July 2013, we filed a joint application with NMGC and Continental Energy Systems LLC with the NMPRC for approval of the acquisition. On Dec. 2, 2013, the Hearing Examiner in the application for approval of the acquisition issued an order approving the motion filed by TECO Energy, Inc., NMGC, Continental Energy Systems LLC, the Staff of the NMPRC, and the New Mexico Attorney General's Office (the "Parties") requesting additional time for proceedings in the matter.

On Jan. 10, 2014, the Parties and the Hearing Examiner met to establish a new schedule. The new key dates established in that meeting are: Staff and intervenor testimony due on or before Feb. 28, hearings before the Hearing Examiner to follow on March 24 to 28. The date for a final decision is yet to be determined. With this schedule, closing will likely occur in the third quarter of 2014. Also under this schedule, closing of the transaction will not occur by July 24, 2014, which will trigger the need to file a new Hart-Scott-Rodino Premerger Notification and Report Form with the Department of Justice. Closing of the transaction would be subject to renewed clearance from anti-trust regulators and expiration of the new waiting period under the filings.

Except where specifically noted and discussed this MD&A excludes the impact of NMGC and related financing activities on our expected financial results throughout the forecast periods presented herein. (See the **Item 1A. Risk Factors**, **Financing Activities**

Related to NMGC, Credit Facility Related to NMGC and **TECO Finance Bridge Facility Related to NMGC** sections and see **Note 22** to the **TECO Energy Consolidated Financial Statements**.)

2013 PERFORMANCE

All amounts included in this MD&A are after tax, unless otherwise noted.

In 2013, our net income attributable to TECO Energy was $197.7 million, or $0.92 per share, compared with $212.7 million, or $0.99 per share, in 2012. Net income from continuing operations was $197.8 million, or $0.92 per share, in 2013, compared with $246.0 million, or $1.14 per share, in 2012.

In 2013, non-GAAP results from continuing operations, which exclude $6.2 million of costs associated with the pending acquisition of NMGC, were $204.0 million, or $0.95 on a per-share basis, compared with $246.0 million, or $1.14 per share, in 2012 when there were no adjustments to GAAP results.

The most significant factor impacting the year-over-year-comparison of results was the impact of weak coal markets, which reduced TECO Coal's earnings by $41.2 million. Tampa Electric and PGS benefited from customer growth of 1.5% and 1.3%, respectively, and therm sales and net income at the gas utility increased. While we expected Tampa Electric's 2013 results to be lower than 2012, initial revenues from its rate settlement became effective in November and significantly mitigated the impact of the rate base and O&M expense growth that had necessitated the company's 2013 rate filing.

Major events in 2013 included Tampa Electric's base rate case settlement, receiving final approval for Tampa Electric's Polk Power Station generation expansion project, and activities toward achieving a successful closing and integration of NMGC in 2014. In September, the FPSC approved a settlement agreement among Tampa Electric and intervenors that resolved all issues in Tampa Electric's 2013 base rate case and provided for additional base rates to become effective in 2017 at the time the generation expansion project commences service, thus eliminating the need for an additional rate case in 2016 and providing revenue clarity for at least four years (see the **Tampa Electric** section). In 2013, Tampa Electric obtained the final approvals for the conversion of the Polk Power Station Units 2-5 from peaking service to combined cycle. The final air emissions permits were received in January 2014, and construction commenced at that time.

In 2012, net income was $212.7 million, or $0.99 per share, compared with $272.6 million, or $1.27 per share, in 2011. The 2012 full-year net income from continuing operations was $246.0 million, or $1.14 per share, compared with $250.8 million, or $1.17 per share, in 2011. The 2012 full-year loss reported in discontinued operations, which was related to the sale of TECO Guatemala, was $33.3 million, or $0.15 per share, compared with net income of $21.8 million, or $0.10 per share, in 2011.

There were no charges or gains to cause non-GAAP results to differ from net income in 2012 or in 2011.

OUTLOOK

Our outlook for 2014 results reflects our expectations that our Florida utilities will deliver strong earnings growth and returns at or above the middle of their allowed ROE ranges, and that TECO Coal results will be about break-even and cash positive. We expect that the combined earnings growth of our two regulated Florida utilities will exceed 13% in 2014. The major driver for Tampa Electric is the expected $50 million of higher base revenues as a result of the 2013 rate settlement. We expect that O&M expenses in 2014 will be lower than 2013, and that continued growth in the local economy will yield annual customer growth similar to 2013. As construction spending on the Polk Power Station increases, Tampa Electric is expected to have higher AFUDC earnings as well. We anticipate that PGS will earn above the midpoint of its allowed ROE range of 9.75% to 11.75%, with continued customer growth as well as volume growth, driven in part by positive trends in the state and local economies and continued interest in converting vehicle fleets to compressed natural gas.

The drivers impacting 2014 are summarized below and discussed in further detail in the individual operating company sections. The discussion below excludes any impact from the acquisition of NMGC or related financing activities. Results from NMGC will depend on the timing of the closing, the interest rate on the debt to be issued and the number of shares sold to finance the transaction, among other factors.

Tampa Electric expects customer growth in 2014 to continue at a pace similar to 2013, with 1.5% higher average number of customers. Total retail energy sales growth is expected to average about 0.5% lower than customer growth due to lower average customer usage. Sales to the lower margin industrial-phosphate customers are expected to be lower in 2014 due to increased self-generation from new generating and transmission facilities owned by these customers, after the in-service dates for these facilities were delayed in 2013. PGS expects customer growth consistent with trends in 2013 when the average number of customers increased 1.2%. PGS expects energy sales volumes to be higher than in 2013, assuming normal weather conditions, as mild winter temperatures reduced natural gas volumes sold in 2013. It also expects to benefit from customers converting from petroleum and other fuel sources to natural gas due to the attractive economics. Interest in compressed natural gas (CNG) vehicle fleets is growing steadily with additional filling stations and more vehicle conversions expected in 2014.

Due to the current very weak domestic and international coal market conditions, we expect TECO Coal's results to be about break even, but cash positive at the middle of the cost and sales guidance ranges in 2014. TECO Coal expects to sell between 5.5 and 6.0 million tons in 2014 with 80% of its sales contracted and priced, 15% of its sales committed but subject to quarterly price adjustments, and 5% unsold. The average selling price across all products is expected to be $80 per ton, which is $5 per ton lower than in 2013, while the fully-loaded, all-in cost of production is expected to be in a range between $79 and $83 per ton, which is lower than the $84 per ton average cost in 2013 and reflects the benefit of actions taken in 2013 to reduce costs.

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

Our priority for the use of cash is investment in our Florida utilities to support their capital spending programs while maintaining their capital structures and financial integrity, and over time reduction of parent debt. In 2014, we will use cash on hand to fund a portion of the NMGC acquisition. In 2014, we expect to make additional equity contributions to Tampa Electric and PGS of $125 million and $25 million, respectively. Our opportunities to invest capital in Tampa Electric are expected to grow significantly over the next several years as it completes its next increment of new generating capacity. We anticipate capital spending in 2014 to increase to $700 million at the regulated Florida utilities, including the investments in generating capacity additions at Tampa Electric and opportunities to grow the PGS system described below (see the **Liquidity, Capital Resources** section).

TECO Coal, with its dedicated work force and management team, has delivered strong earnings and cash flow to us for many years. With our focus clearly on growing our regulated operations, we do not consider TECO Coal to be a core holding. The coal business is a commodity business, which, by its nature, is cyclical with earnings volatility, which is not the earnings profile we believe our investors seek. If an opportunity to sell TECO Coal presents itself, we would consider such an offer. In the event of a sale of this business, we could use the proceeds to pay for a portion of the acquisition of NMGC, or repay parent debt. However, at this time a sale of TECO Coal on acceptable terms is uncertain.

We have evaluated trends, strategies and opportunities affecting our regulated utilities, to sharpen the focus on developing longer-range plans to take advantage of emerging growth opportunities and some fundamental changes in our industry. Over time, we expect these initiatives to contribute to organic earnings growth. Some of the areas that we are currently focused on include:

- We believe there are opportunities to grow the use of CNG for fleet vehicles. In 2013, the Florida legislature enacted legislation supportive of CNG vehicle conversions through rebates and tax incentives. To date, we have had success working with fleet owners to install 21 CNG filling stations with completed conversions or planned conversions in 2014 of almost 1,000 vehicles of various sizes to CNG. The number of vehicles already converted or committed to conversion will consume almost 10 million therms annually, the equivalent consumption of more than 43,000 typical residential customers. Such conversions offer compelling economics to customers, and expand PGS therm sales without significant capital investment by PGS.
- We are looking closely at Smart Grid applications that have proven technology and offer operating and financial benefits to our overall operations. These include, among other opportunities, transitioning automatic meter reading technology to advanced metering infrastructure, which would include a significant investment in our communications infrastructure but would also result in O&M expense savings.
- We also recognize that there is a growing demand for natural gas generation in Florida over the next decade. We project that Florida may need between 0.8 and 1.25 billion cubic feet per day (Bcf/day) by as early as 2016. Given our expertise in this area, we continue to evaluate opportunities to partner with transmission and end-use natural gas customers.

At PGS, the business model for system expansion evolved over the past several years to focus on extending the system to serve large commercial and industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future make it attractive for these customers to convert from fuels that are currently more expensive on a cost per MMBTU basis.

Previously, during periods of robust residential growth, PGS extended its system to serve large residential housing developments, and commercial growth followed the residential development. In the current environment where fewer large residential projects are being developed, commercial and industrial-led expansion allows PGS to continue to provide clean and economical natural gas to areas of the state previously unserved and to be positioned to serve future residential growth.

RESULTS SUMMARY

The table below compares our GAAP net income to our non-GAAP results. A reconciliation between GAAP net income and non-GAAP results is contained in the **Reconciliation of GAAP net income from continuing operations to non-GAAP results** tables for 2013. A non-GAAP financial measure is a numerical measure that includes or excludes amounts, or is subject to adjustments that have the effect of including or excluding amounts that are excluded or included from the most directly comparable GAAP measure (see the **Non-GAAP Information** section).

Results Comparisons

(millions)	***2013***	*2012*	*2011*
Net income attributable to TECO Energy	**$197.7**	$212.7	$272.6
Net income from continuing operations	**$197.8**	$246.0	$250.8
Non-GAAP results from continuing operations	**$204.0**	$246.0	$250.8

The table below provides a summary of revenues, earnings per share, net income and shares outstanding for the 2013-2011 period.

Earnings Summary

(millions) Except per-share amounts	***2013***	*2012*	*2011*
Consolidated revenues	**$2,851.3**	$2,996.6	$3,209.9
Earnings per share – basic			
Earnings per share from continuing operations	**$ 0.92**	$ 1.14	$ 1.17
Earnings (loss) per share from discontinued operations	**--**	(0.15)	0.10
Earnings per share attributable to TECO Energy	**$ 0.92**	$ 0.99	$ 1.27
Earnings per share – diluted			
Earnings per share from continuing operations	**$ 0.92**	$ 1.14	$ 1.17
Earnings (loss) per share from discontinued operations	**--**	(0.15)	0.10
Earnings per share attributable to TECO Energy	**$ 0.92**	$ 0.99	$ 1.27
Net income from continuing operations	**$ 197.8**	$ 246.0	$ 250.8
Net income (loss) from discontinued operations	**(0.1)**	(33.3)	21.8
Net income attributable to TECO Energy	**197.7**	212.7	272.6
Charges and (gains)(1)	**6.2**	--	--
Non-GAAP results	**$ 204.0**	$ 212.7	$ 272.6
Average common shares outstanding (millions)			
Basic	**215.0**	214.3	213.6
Diluted	**215.5**	215.0	215.1

(1) See the GAAP to non-GAAP reconciliation table that follows.

The following table shows the specific adjustments made to GAAP net income for each segment to develop our 2013 non-GAAP results.

There were no charges or gains in 2012 or 2011 to cause non-GAAP results to differ from net income from continuing operations.

2103 Reconciliation of GAAP Net Income to Non-GAAP Results

Net income impact (millions)	Tampa Electric	PGS	TECO Coal	Parent/ other(1)	Total Continuing Operations	Discontinued Operations(1)	Total
GAAP Net income attributable to TECO Energy	$190.9	$34.7	$9.0	$(36.8)	$197.8	$(0.1)	$197.7
Costs associated with the acquisition of NMGC	—	—	—	6.2	6.2	—	6.2
Total charges	—	—	—	6.2	6.2		6.2
Non-GAAP results	$190.9	$34.7	$9.0	$(30.6)	$204.0	$(0.1)	$203.9

(1) Certain costs previously included in Parent/other have been recast to Discontinued Operations.

NON-GAAP INFORMATION

From time to time, in this MD&A, we provide non-GAAP results, which present financial results after elimination of the effects of certain identified charges and gains. In 2012 and 2011, there were no charges or gains to cause non-GAAP results to differ from net income from continuing operations. 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 results may not be comparable to similarly titled measures used by other companies.

While none of the particular excluded items are expected to recur, there may be adjustments to previously estimated gains or losses related to the disposition of assets 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.

OPERATING RESULTS

This MD&A 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 on a GAAP basis (see **Note 14** to the **TECO Energy Consolidated Financial Statements**).

(millions) Except per share amounts		***2013***	*2012*	*2011*
Segment revenues (1)				
Regulated companies	Tampa Electric	**$1,950.5**	$1,981.3	$2,020.6
	PGS	**393.5**	398.9	453.5
Total regulated		**$2,344.0**	$2,380.2	$2,474.1
	TECO Coal	**$ 496.2**	$ 608.9	$ 733.0
Net income (2)				
Regulated companies	Tampa Electric	**$ 190.9**	$ 193.1	$ 202.7
	PGS	**34.7**	34.1	32.6
Total regulated		**225.6**	227.2	235.3
	TECO Coal	**9.0**	50.2	51.5
	Parent/other(4)	**(36.8)**	(31.4)	(36.0)
Net income from continuing operations		**197.8**	246.0	250.8
Net income (loss) from discontinued operations		**(0.1)**	(33.3)	21.8
Net income attributable to TECO Energy		**$ 197.7**	$ 212.7	$ 272.6
Earnings per share - basic (2)(3)				
Regulated companies	Tampa Electric	**$ 0.89**	$ 0.90	$ 0.95
	PGS	**0.16**	0.16	0.15
Total regulated		**1.05**	1.06	1.10
	TECO Coal	**0.04**	0.23	0.24
	Parent/other(4)	**(0.17)**	(0.15)	(0.17)
Earnings per share from continuing operations		**0.92**	1.14	1.17
Earnings (loss) per share from discontinued operations		**--**	(0.15)	0.10
Earnings per share attributable to TECO Energy		**$ 0.92**	$ 0.99	$ 1.27
Average shares outstanding – basic		**215.0**	214.3	213.6

(1) Segment revenues include intercompany transactions that are eliminated in the preparation of TECO Energy's consolidated financial statements.
(2) Segment net income and earnings per share are reported on a basis that includes internally allocated interest costs to the unregulated companies. Internally allocated interest costs were at a pretax interest rate of 6.00% for 2013 and 2012, and 6.25% for 2011.
(3) The number of shares used in the earnings-per-share calculations is basic shares.
(4) From continuing operations

TAMPA ELECTRIC

Electric Operations Results

Net income in 2013 was $190.9 million compared with $193.1 million in 2012. Results in 2013 reflected 1.5% customer growth, higher base revenues effective Nov. 1, 2013 as a result of the rate case settlement, and energy sales, weather and customer usage patterns similar to 2012. Higher O&M was partially offset by lower interest expense. Net income included $6.3 million of AFUDC–equity, which represents allowed equity cost capitalized to construction costs, compared with $2.6 million in the 2012 period. Net income also reflected $3.6 million lower earnings on assets recovered through the ECRC due to an FPSC rule revising the return on investment calculation effective Jan. 1, 2013.

In 2013, total degree days in Tampa Electric's service area were 1% below normal, and 1% below the prior full-year period, reflecting generally milder weather early in the year. Pretax base revenues were $13 million higher than in 2012, primarily due to $10 million of higher base rates effective Nov. 1, 2013, and higher energy sales late in the year due to unusually warm early winter weather. Total net energy for load, which is a calendar measurement of retail energy sales rather than a billing-cycle measurement, decreased 0.4% in 2013 compared with 2012. The energy sales shown in the summary table below reflect the energy sales based on the timing of billing cycles, which can vary from period to period.

O&M expenses, excluding all FPSC-approved cost-recovery clauses, increased $19.4 million in 2013, reflecting $8.2 million of higher accruals for performance-based incentive compensation for all employees based on achievement of financial goals and higher costs to operate and maintain the transmission and distribution systems. Compared to 2012, depreciation and amortization expense increased $0.7 million, reflecting the impact of additions to facilities to serve customers, largely offset by approximately $4.0 million of lower amortization on software retroactive to Jan. 1, 2013, due to the change in life for software agreed to in the base rate case settlement. Interest expense decreased $11.1 million, due to lower long-term debt interest rates and balances and a lower interest rate on customer deposits.

Net income in 2012 was $193.1 million, compared to $202.7 million in 2011. Results in 2012 reflected a mild winter weather period and an extremely rainy summer period, and lower per-customer average usage, partially offset by 1.2% growth in the average number of customers, higher O&M expense and lower interest expenses. Net income in 2012 included $2.6 million of AFUDC-equity, compared with $1.0 million in the 2011 period.

In 2012, total degree days in Tampa Electric's service area were normal, but almost 3% below the prior year, reflecting mild winter weather and an unusually rainy summer weather pattern (the second wettest summer period on record) offset by higher than normal degree days in the normally mild spring and fall periods, which do not generate significantly higher energy sales. Pretax base revenue was almost $6.0 million lower than in 2011, primarily reflecting lower sales to residential customers from the milder weather, voluntary conservation that typically occurs during periods without extreme weather, and changes in customer usage patterns. In 2012, total net energy for load was 0.3% higher than in 2011.

In 2012, O&M expense, excluding all FPSC-approved cost-recovery clauses, increased $11.8 million reflecting higher generating system maintenance expenses, higher costs to operate and maintain the distribution system and higher pension and other employee benefit expenses, partially offset by lower bad-debt expense. Compared to the 2011 full-year period, depreciation and amortization expense increased $9.6 million, reflecting additions to facilities to serve customers. Interest expense decreased $7.4 million due to lower long-term debt interest rates and balances and a lower interest rate on customer deposits.

Base Rates

Prior to Nov. 1, 2013, Tampa Electric's results reflected base rates established in March 2009, when the FPSC awarded $104.0 million higher revenue requirements effective in May 2009 that authorized an ROE mid-point of 11.25%, 54.0% equity in the capital structure, and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for combustion turbines and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

As a result of growth in rate base from required infrastructure added to serve customers, increasing pressure on O&M expense, and an economic recovery that was slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding in 2009, on April 5, 2013, Tampa Electric filed its petition with the FPSC for an increase in base rates and miscellaneous service charges in the amount of $134.8 million. In the petition, Tampa Electric requested an ROE level of 11.25% and a capital structure identical to that approved in 2009, with 54% equity.

After extensive testimony by Tampa Electric and discovery by five intervening parties and the FPSC Staff, on Sept. 6, 2013, Tampa Electric and all of the intervening parties reached a Stipulation and Settlement Agreement resolving all of the issues in the proceeding. On Sept. 11, 2013, the FPSC approved the settlement that authorized base rate increases implemented at four different dates.

Under the settlement agreement, Tampa Electric was granted $57.5 million higher annual base rates effective Nov.1, 2013, an additional $7.5 million effective Nov. 1, 2014, an additional $5.0 million increase effective Nov.1, 2015, and $110 million of higher base rates effective Jan. 1, 2017, or when the Polk 2 – 5 conversion enters commercial service, whichever is later (see the **Regulation** section).

The table below provides a summary of Tampa Electric's revenue and expenses and energy sales by customer type.

Summary of Operating Results

(millions)	***2013***	*% Change*	*2012*	*% Change*	*2011*
Revenues	**$1,950.5**	(1.6)	$1,981.3	(1.9)	$2,020.6
O&M expenses	**427.0**	13.7	375.7	7.6	349.2
Depreciation and amortization	**238.8**	0.5	237.6	7.0	221.1
Taxes, other than income	**149.7**	(1.1)	151.3	5.4	143.6
Non-fuel operating expenses	**815.5**	6.7	764.6	7.0	713.9
Fuel expense	**681.9**	(1.8)	694.7	(5.3)	733.5
Purchased power expense	**64.6**	(38.7)	105.3	(16.4)	125.9
Total fuel & purchased power expense	**746.5**	(6.7)	800.0	(6.9)	859.4
Total operating expenses	**1,562.0**	(0.2)	1,564.6	(0.6)	1,573.3
Operating income	**388.5**	(6.8)	416.7	(6.6)	447.3
AFUDC equity	**6.3**	142.3	2.6	160.0	1.0
Net income	**$ 190.9**	(1.1)	$ 193.1	(4.7)	$ 202.7
Megawatt-Hour Sales (thousands)					
Residential	**8,470**	0.9	8,395	(3.7)	8,718
Commercial	**6,090**	(1.5)	6,185	(0.4)	6,207
Industrial	**2,027**	1.2	2,001	10.9	1,804
Other	**1,832**	0.2	1,828	(0.3)	1,835
Total retail	**18,418**	--	18,409	(0.8)	18,564
Sales for resale	**222**	(16.8)	267	(24.2)	352
Total energy sold	**18,640**	(0.2)	18,676	(1.3)	18,916
Retail customers - (thousands)					
Average	**694.7**	1.5	684.2	1.2	675.8
Retail net energy for load	**19,178**	(0.4)	19,255	0.3	19,205

Operating Revenues

In 2013, retail MWh sales, as measured on a billing cycle basis shown in the table above, were essentially unchanged from 2012. Similar to 2012, sales in 2013 reflected a mild winter and a rainy summer period and lower per customer usage, partially offset by 1.5% customer growth and improvements in the local economy. Pretax base revenue, which included $10.0 million of higher revenue as a result of the base rate settlement described above, was approximately $13.0 million higher than in 2012. In 2013, total retail net energy for load decreased 0.4%, compared to the 2012 period. In 2013, total degree days in Tampa Electric's service area were 1% below normal, and 1% below 2012, reflecting generally milder weather early in the year.

In 2012, retail MWh sales, as measured on a billing cycle basis shown in the table above, decreased 0.8% despite 1.2% higher average number of customers, an improving local economy and higher sales to the lower margin phosphate-industrial customers. In 2012, total degree days in Tampa Electric's service area were normal, but almost 3% below 2011, reflecting mild winter weather and an unusually rainy summer weather pattern offset by higher than normal degree days in the normally mild spring and fall periods, which do not generate significantly higher energy sales. Pretax base revenue was almost $6.0 million lower than in 2011, primarily reflecting lower sales to residential customers from the milder weather, changes in customer usage patterns and voluntary conservation that typically occurs during periods without extreme weather. In 2012, total net energy for load, which is a calendar measurement of retail energy sales rather than a billing cycle measurement, was 0.3% higher than in 2011.

For the past several years, weather-normalized energy consumption per residential customer declined due to the combined effects of voluntary conservation efforts, economic conditions, improvements in lighting and appliance efficiency, smaller single-family houses and increased multi-family housing.

Sales for resale, which are a decreasing portion of Tampa Electric's energy sales, declined 16.8% in 2013 and 24.2% in 2012, primarily due to changes in Tampa Electric's wholesale rates and reduced demand due to the mild weather.

Customer and Energy Sales Growth Outlook

The Florida economy continues to improve following the economic downturn, as evidenced by lower levels of unemployment, and slow improvements in the new housing construction market, which was a major driver of growth in the Florida economy for many years (see the **Risk Factors** section). In general, economists are forecasting a continued improvement in the unemployment rate in 2014, and an acceleration of improvement in the economy in 2014 and beyond. The 2014 forecast used by Tampa Electric reflects a continuation of the customer growth that was experienced in 2013. Energy sales are expected to reflect continued lower per customer usage in response to increased energy efficiency, voluntary conservation, and economic conditions. The average number of customers increased 1.5% in 2013 and 1.2% in 2012.

Longer-term, assuming continued economic recovery and resumed growth from population increases and more robust business expansion, Tampa Electric expects average annual customer growth of about 1.5% and weather-normalized average retail energy sales growth about 0.5% lower than customer growth in the near term, and about 0.3% lower than customer growth over the longer-term. This energy sales growth projection reflects increased lighting and appliance efficiency, smaller new single family homes, increased percentage of multi-family homes, changes in usage patterns and changes in population trends. These growth projections assume continued local area economic growth, normal weather, and a continuation of the current energy market structure.

The economy in Tampa Electric's service area continued to grow in 2013 after modest growth in 2012 and 2011. The Tampa metropolitan area had the largest gain in jobs of 22 metropolitan areas in Florida, with more than 35,000 new jobs led primarily by business services, construction and healthcare related businesses. The total nonfarm employment in the Tampa metropolitan area increased 3.5% in 2013 following a 1.8% increase in 2012 and 1.2% in 2011. The increase in nonfarm employment compared favorably with the state of Florida's increase of 2.5%. The local Tampa area unemployment rate decreased to 5.7% at the end of 2013 compared with 7.6% at year-end 2012 and 9.5% at year-end 2011. The Tampa area year-end 2013 unemployment rate was below the state of Florida's 6.2% rate and the national rate of 7.0%. The Tampa area, Florida and national unemployment rates were 7.6%, 8.0% and 7.8%, respectively, at year-end 2012, and 9.5%, 9.7% and 8.5%, respectively, at year-end 2011.

Operating Expenses

Total pretax operating expenses were 0.2% lower in 2013, driven primarily by higher other operating expenses more than offset by lower fuel and purchased-power expense. Excluding all FPSC-approved cost-recovery clause-related expenses, O&M expenses increased $19.4 million in 2013 reflecting $8.2 million of higher accruals for performance-based incentive compensation for all employees based on achievement of financial goals and higher costs to operate and maintain the transmission and distribution systems.

Total pretax operating expenses decreased 0.6% in 2012 driven primarily by lower fuel and purchased power expenses. Excluding all FPSC approved cost-recovery clause related expenses, which are net-income neutral, O&M expense increased 6.6%, or $11.8 million, driven by higher generating system maintenance expenses, higher costs to operate and maintain the distribution system and higher pension and other employee benefit expenses, partially offset by lower bad-debt expense.

Compared to 2012, depreciation and amortization expense increased $0.7 million in 2013 primarily as a result of approximately $4.0 million of lower amortization on software retroactive to Jan. 1, 2013, due to the change in depreciable life for software agreed to in the base rate case settlement, more than offset by depreciation of additions to facilities to serve customers. In 2014, depreciation expense is expected to increase at more normal levels, similar to those experienced in 2012. Compared to 2011, depreciation and amortization expense increased $9.5 million in 2012, reflecting additions to facilities to serve customers.

Excluding all FPSC-approved cost-recovery clause-related expenses, O&M expense is expected to decrease in 2014 due to lower employee-related costs, lower storm damage expense accruals, and lower pension expense driven by higher discount rates partially offset by higher costs to operate the system and reliably serve customers. Under the rate settlement approved by the FPSC in September 2013, Tampa Electric discontinued its annual $8 million pretax storm damage expense accrual effective Nov. 1, 2013.

Fuel Prices and Fuel Cost Recovery

In November 2013, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2014. The rates include the expected cost for natural gas and coal in 2014, and the net over-recovery of fuel, purchased power and capacity clause expenses.

Total fuel cost decreased in both 2013 and 2012, due to increased natural gas-fired generation and lower costs for natural gas and coal. Purchased-power expense decreased in 2013 and 2012 as the cost-per-MWh decreased, due to lower natural gas prices, which is the primary fuel used by other generators in Florida. Delivered natural gas prices decreased 2% in 2013 after a 14.0% decline in 2012 as a result of low natural gas prices due to mild winter weather and abundant supplies from on-shore domestic natural gas produced from shale formations, and storage inventories above historic averages. Delivered coal costs decreased 5.3% in 2013. The average coal and natural gas costs were $3.38/MMBTU and $5.23/MMBTU, respectively, in 2013.

Natural gas futures as traded on the NYMEX and various forecasts for natural gas prices indicate that natural gas prices are expected to increase in 2014, as fewer new natural gas wells are drilled in on-shore shale gas formations due to the low prices received by the producers, and a shift by the producers to drilling for more oil than natural gas. Cold winter weather early in 2014 and resulting draws on inventories in storage, improved industrial demand from continued improvement in the economy, and the expectation for more-normal weather are expected to contribute to higher prices as well. Beyond 2014, forecasts are for stable to slightly rising natural gas prices for several years due to increased availability of domestic supplies of natural gas. Delivered coal prices decreased 5.3% in 2013 due to lower transportation costs as a result of lower fuel oil prices, and lower prices for coal purchased in the spot market. Tampa Electric's primary coal supplies are from the Illinois Basin, which have been more stable than the Central Appalachian coal-producing region over the past several years. Excluding normal escalation and transportation costs, Tampa Electric's coal prices are expected to remain stable in 2014 due to long-term supply contracts.

Energy Supply

Tampa Electric's generation increased in line with energy sales growth in 2013, and purchased power decreased due to higher gas-fired generation by Tampa Electric. Tampa Electric's generation decreased in 2012 due to the mild weather and lower cost natural gas-fired generation available within Florida, which increased MWh purchased but at a lower cost. Lower natural gas prices also contributed to the decrease in purchased-power expense on a per-MW basis.

Prior to the conversion of the coal-fired Gannon Station to the natural gas-fired Bayside Power Station in 2003, nearly all of Tampa Electric's generation was from coal. Upon completion of that conversion, the mix shifted with the increased use of natural gas. Coal is expected to continue to represent a significant portion of Tampa Electric's fuel mix due to the baseload units at the Big Bend Power Station and the coal gasification unit, Polk Unit 1. Longer term, natural gas prices are expected to remain stable for several years, and we expect to maintain the generation mix at about current levels.

Polk Power Station Units 2 – 5 Combined Cycle Conversion

In 2011, Tampa Electric announced that, subject to FPSC approval, it planned to convert four CTs in peaking service at the Polk Power Station to combined cycle with an early 2017 in-service date. In 2012, as required under Florida regulations, Tampa Electric issued a request for proposal to determine its lowest cost option to provide generating capacity beginning in early 2017. The bid process showed that the lowest cost option to serve customers, over the long-term, was Tampa Electric's planned conversion of CTs to combined-cycle operation.

In September 2012, Tampa Electric submitted a petition to the FPSC for a Determination of Need for the conversion of these peaking CTs to combined-cycle service. In December 2012, the FPSC conducted a hearing for the need, and the FPSC made a bench decision to approve the Polk Power Station Units 2 – 5 conversion. In November 2013, the governor of Florida and the Cabinet, acting as the Power Plant Siting Board, approved the construction of the conversion. In January 2014, the final emission permits were received and construction commenced. The capital expenditures for the conversion and the related transmission system improvements to support the additional generating capacity are included in the capital expenditure forecast located in the **Capital Expenditures** section. Capital spending in 2014 will support engineering and design, equipment procurement and initial construction. (See the **Capital Expenditures** and **Regulation** sections.)

PGS

Operating Results

In 2013, PGS reported net income of $34.7 million, compared with $34.1 million in 2012. Results reflected a 1.3% higher average number of customers and higher therm sales to all retail customer classes, due to more-normal first quarter weather and better economic conditions. Sales to power generation customers and off-system sales decreased due to the expiration of two contracts with power generators, new participants in the market, and higher natural gas prices in 2013 compared to 2012. Non-fuel O&M expense increased $4.0 million compared to 2012 due to higher employee related costs, including $1.5 million of higher accruals for performance-based incentive compensation for all employees based on achievement of financial goals, and an insurance recovery that reduced O&M expenses in 2012. Interest expense decreased $1.6 million, due to lower long-term debt interest rates and a lower interest rate on customer deposits.

In 2013, total throughput for PGS was almost 1.7 billion therms, down 10% from 2012 levels due to the lower volumes transported for power generation customers and lower off-system sales. Industrial and power generation customers represented approximately 61% of annual therm volume, commercial customers used approximately 26%, approximately 9% was sold off-system, and the remainder was consumed by residential customers.

In 2012, PGS reported net income of $34.1 million, compared with $32.6 million in 2011. Results in 2012 reflected a 1.2% higher average number of customers, but lower sales to residential customers due to mild winter weather more than offset by higher sales to commercial and industrial customers and power generation customers due to improving economic conditions. Volumes for the low-margin transportation service for electric power generators were higher than in 2011 due to low natural gas prices, which made it more economical to use natural gas for power generation. Non-fuel O&M expense decreased $2.1 million, compared with 2011, due in part to an insurance recovery of legal expenses associated with environmental-contamination claims. In 2011, O&M expense included $2.5 million related to legal expenses associated with environmental-contamination claims. Interest expense decreased $1.0 million due to lower long-term debt interest rates and balances and a lower interest rate on customer deposits. Depreciation expense increased $1.4 million reflecting additions to facilities to serve customers.

In 2012, the total throughput for PGS was almost 1.9 billion therms. Industrial and power generation customers consumed approximately 62% of PGS's annual therm volume, commercial customers used approximately 22%, approximately 12% was sold off system, and the balance was consumed by residential customers.

Residential operations were about 32% of total revenues in each of the past three years. New residential construction, which includes natural gas and conversions of existing residences to natural gas has slowed significantly, compared to the pre-2007 period, due to the weaker Florida housing market. Like most other natural gas distribution utilities, PGS is adjusting to lower per-customer usage due to improving appliance efficiency. As customers replace existing gas appliances with newer, more efficient models, per-customer usage tends to 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. PGS has also experienced increased interest in the usage of CNG as an alternative fuel for vehicles. Currently, there are 21 CNG fueling stations connected to the PGS system, and, at this time, an additional six stations are expected to be added in 2014, however the number of new stations may increase as the year progresses. Such initiatives add therm sales, at lower-margin transportation rates, to the gas system without requiring significant capital investment by PGS.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a PGA. Because this charge may be adjusted monthly based on a cap approved by the FPSC annually, PGS normally has a lower percentage of under- or over-recovered gas cost variances than Tampa Electric.

The table below provides a summary of PGS's revenue and expenses and therm sales by customer type.

Summary of Operating Results

(millions)	***2013***	*% Change*	*2012*	*% Change*	*2011*
Revenues	**$393.5**	(1.3)	$398.9	(12.0)	$453.5
Cost of gas sold	**142.6**	(9.5)	157.6	(25.4)	211.3
Operating expenses	**181.1**	6.5	170.0	(1.3)	172.2
Operating income	**69.8**	(2.1)	71.3	1.9	70.0
Net income	**34.7**	1.8	34.1	4.6	32.6

Therms sold – by customer segment					
Residential	**74.4**	5.0	70.8	(8.9)	77.7
Commercial	**438.1**	4.0	421.4	3.0	409.2
Industrial	**415.1**	(10.0)	461.3	5.8	436.1
Power generation	**744.4**	(18.5)	913.5	48.7	614.3
Total	**1,672.0**	(10.4)	1,867.0	21.4	1,537.3
Therms sold – by sales type					
System supply	**249.5**	(25.4)	334.3	(5.4)	353.3
Transportation	**1,422.5**	(7.2)	1,532.7	29.5	1,184.0
Total	**1,672.0**	(10.4)	1,867.0	21.4	1,537.3
Customer (thousands) – average	**347.4**	1.3	342.9	1.2	338.8

In Florida, natural gas service is unbundled for non-residential customers and residential customers that use more than 1,999 therms annually that elect this option, affording these customers the opportunity to purchase gas from any provider. The net result of unbundling is a shift from bundled transportation and commodity sales to transportation-only 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 earnings impact to the company when a customer shifts to transportation-only sales. PGS markets its unbundled gas delivery services to customers through its "NaturalChoice" program. At year-end 2013, approximately 20,500 out of 35,000 of PGS's eligible non-residential customers had elected to take service under this program.

PGS Outlook

In 2014, PGS expects continued customer growth at rates in line with those experienced in 2013, reflecting its expectations that the housing markets in many areas of the state that it serves are now recovering. Assuming normal weather, therm sales to weather-sensitive customers, especially residential customers, are expected to increase in 2014 compared to 2013 when mild winter weather late in the year limited sales. Excluding all FPSC-approved cost-recovery clause-related expenses, O&M expense is expected to decrease slightly in 2014 primarily due to higher costs to operate the system more than offset by lower employee-related expenses, which includes pension expense driven by higher discount rates in the current interest rate environment and better pension plan asset performance in 2013. Depreciation expense is expected to increase from continued capital investments in facilities to reliably serve customers.

Since its acquisition by TECO Energy in 1997, PGS has expanded its gas distribution system into areas of Florida not previously served by natural gas, such as the lower southwest coast in the Fort Myers and Naples areas and the northeast coast in the Jacksonville area. In 2014, PGS expects capital spending to support moderate residential and commercial customer growth, system expansion to serve large commercial and industrial customers, continued interest in conversion of vehicle fleets to CNG and replacement of cast iron and bare steel pipe.

Due to the current rate of new residential development in Florida, which is considerably slower than the 2005 to 2007 period, the PGS business model for system expansion has evolved to focus on extending the system to serve large commercial or industrial customers that are currently using petroleum and propane as fuel. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future makes it attractive for these customers to convert from fuels that are currently three to four times more expensive on a cost-per-MMBTU basis.

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 FGT through 66 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's Jacksonville Division receives gas delivered by the Southern Natural Gas Company pipeline through two gate stations located northwest of Jacksonville. PGS also receives gas delivered by Gulfstream Natural Gas Pipeline through six gate stations, and by its affiliate, SeaCoast Gas Transmission LLC, through a single gate station in northeast Florida.

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

In 2013, TECO Coal recorded net income of $9.0 million on sales of 5.8 million tons, compared with $50.2 million on sales of 6.3 million tons in 2012. The 2013 full-year average net selling price was almost $85 per ton, compared with $95 per ton in 2012. The lower sales volumes and lower selling prices in 2013 reflect the current ongoing weak domestic and international coal markets. The all-in total cost of sales was $84 per ton, compared with $85 per ton in the 2012 period. The cost of sales in the first quarter of 2013 included some higher-cost tons from December 2012 inventory that included costs associated with personnel reductions and with idling certain mining operations. TECO Coal recorded a $3.6 million income tax benefit in 2013 that included a $3.7 million tax depletion benefit and a $1.9 million benefit from the reversal of previously accrued state taxes, compared with a 24% effective income tax rate, or a $15.7 million tax expense, in 2012.

In 2012, TECO Coal recorded net income of $50.2 million on sales of 6.3 million tons, compared with $51.5 million on sales of 8.1 million tons in 2011. Lower sales volumes in 2012 reflect much weaker coal market conditions than in 2011. Because the 2012 sales were contracted at a time when the markets were much stronger, the 2012 average net per-ton selling price was more than $95 per ton, compared with almost $88 per ton in 2011. The all-in total per-ton cost of sales was more than $85 per ton compared with almost $80 per ton in 2011. The 2012 cost of sales reflected spreading fixed costs over fewer tons, and costs associated with personnel reductions and with idling certain mining operations. TECO Coal's effective income tax rate was 24% in 2012, compared with 23% in 2011.

TECO Coal Outlook

In 2014, we expect TECO Coal's net income to decrease compared with 2013 to about break-even levels from lower contract selling prices. TECO Coal has 80% of its expected 2014 sales of between 5.5 and 6.0 million tons contracted and priced. An additional 15% of expected sales are committed but unpriced and subject to quarterly pricing based on the Asian benchmark price for metallurgical coal. The average selling price across all products is expected to be $80 per ton in 2014, and specialty coal volumes are expected to represent about 70% of total sales.

The all-in total cost of production is expected to be below 2013 levels in a range between $79 and $83 per ton due to actions taken in 2013 and 2012 to reduce mining costs, including converting traditional surface mining operations to lower cost high-wall mining operations, and lower royalty payments and severance taxes, which are a function of selling price. The cash cost of sales, which excludes depreciation and allocated interest, is expected to be about $7 per ton below the all-in cost. In 2014, TECO Coal expects to record tax depletion tax benefits.

Various federal tax overhaul proposals include provisions to eliminate depletion accounting for mineral extraction companies, which would increase TECO Coal's effective income tax rate and reduce net income if those proposals are implemented (see the **Risk Factors** section).

In November 2011, TECO Coal announced that it had made a new discovery of an additional 65 million tons of proven and probable metallurgical coal reserves on properties it controls, and an additional estimated 9 million tons of metallurgical coal classified as resource (non-reserve coal deposits) due to seam thickness. There is an additional 14 million tons of coal classified as resource pending further geologic studies (see **Item 2 Properties** in the **TECO Coal** section). These metallurgical coal reserves are located below existing reserves and substantially all of these reserves are owned by TECO Coal, which eliminates royalty payments. The coal from these reserves can be transported by conveyor belt to an existing preparation plant, which has adequate capacity, and thus eliminate trucking costs. TECO Coal has received the permit amendments from the state of Kentucky related to surface development activities to access these reserves. TECO Coal performed preliminary surface and infrastructure development in 2012, but does not expect to begin the work required to bring these reserves into production until there are clear indications that the current weak metallurgical coal market conditions are improving (see the **Capital Investments** section of **Liquidity, Capital Resources**). TECO Coal allocates its reserves by market category. As a result of this allocation, 40% of the reserves are classified as metallurgical coal, 40% as soft coking/PCI coal and 20% as steam coal. See **Item 2 Properties** in the **TECO Coal** section for a discussion of this allocation.

Since 2008, the issuance of permits by the USACE under Section 404 of the Clean Water Act required for surface mining activities in the Central and Northern Appalachian mining regions has been challenged in the courts by various entities. These challenges have been appealed by various mining companies affected on a number of occasions, but very few permits have been issued over the past several years. At this time, TECO Coal has all of the permits required to meet its 2014 sales projections. See the **Environmental** section, the **Section 404 of the Clean Water Act and Coal Surface Mine Permits** section for a more detailed discussion of surface mining permit activities.

Coal Markets

Prices for metallurgical coal have been very volatile over the past three years, with higher prices in 2010 driven by increased demand from expanding economies in China and India and recovering demand in the U.S. and Europe. During 2010, spot prices for various grades of metallurgical coal produced by TECO Coal and others reportedly ranged from $110 to $180 per short ton. Hard coking coal produced in Australia and sold primarily in Asian markets is the benchmark for metallurgical coal prices worldwide, and it has ranged from $335 per metric ton in the first half of 2011, due to disruptions in supplies from Australia as a result of flooding, to $235 per metric ton in January 2012, to $143 per metric ton in January 2014. The decline in metallurgical coal prices has been driven by oversupply in the market and concerns related to worldwide demand for steel in China and the weak international economy.

In 2012 and 2011, demand for coal used by utilities to generate electricity declined due to low natural gas prices, which made it more economical to generate electricity with natural gas than with coal, mild winter weather, and the slow economic recovery in the United States. Prices for Central Appalachian (CAPP) coal used by utilities did not improve in 2013, and in some periods declined further. Future demand for CAPP coal by utilities is uncertain due to the impact of certain proposed EPA regulations on utilities' ability to burn coal. Various industry reports, and estimates by the EPA, indicated that a number of smaller, older coal-fired utility boilers without current environmental controls would be retired in response to the proposed rules. In December 2011, the United States District Court for the District of Columbia stayed the implementation of the EPA's proposed CSAPR (see the **Environmental** section). In January 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied the EPA's request for reconsideration of its ruling against CSAPR, significantly reducing the possibility that the rule will be enforced in its current form. Despite the stay of CSAPR in 2011, demand for coal by utilities remains weak.

In 2013, the EPA released draft rules for GHG emissions from new utility power plants which would, if implemented as proposed, essentially eliminate the use of coal as a fuel by requiring the use of carbon capture and sequestration. The EPA is scheduled to release draft rules for GHG emission from existing utility power plants in 2014, which increases the uncertainty of future coal use by utilities.

The significant factors that could influence TECO Coal's results in 2014 include the cost of production, the pricing on uncontracted tons, and customers taking contracted volumes. Longer-term factors that could influence results include inventories at thermal coal users, weather, the ability for utilities to continue to burn coal under new rules proposed by the EPA, the ability to obtain environmental permits for mining operations, general economic conditions, the level of natural gas prices, commodity price changes that impact the cost of production, and changes in environmental regulations (see the **Environmental Compliance** and **Risk Factors** sections).

PARENT/OTHER

In 2013, the cost for Parent/other was $36.8 million, compared with $31.4 million in 2012. The non-GAAP cost from continuing operations for Parent/other in 2013 was $30.6 million, which excluded $6.2 million of costs associated with the pending acquisition of NMGC, compared with $31.4 million in 2012.

In 2012, the cost for Parent/other in continuing operations was $31.4 million, compared with $36.0 million in 2011. Results for 2012 reflect tax items and lower interest expense as a result of the mid-year 2011 debt retirement, and a charge of $0.8 million associated with the early retirement of the remaining $8.8 million of TECO Energy parent debt. The total cost for Parent/other for 2012 was $35.4 million, compared with $36.6 million in the same period in 2011. Total cost for 2012 includes transaction costs and tax items recorded at Parent related to the TECO Guatemala discontinued operations.

The 2014 non-GAAP cost for Parent/other is expected to be similar to 2013 levels. This forecast excludes any transaction costs, which will be treated as non-GAAP costs, associated with the NMGC acquisition that will be recorded at Parent/other.

DISCONTINUED OPERATIONS (TECO GUATEMALA)

The 2013 cost of $0.1 million reported in discontinued operations was related to the 2012 sale of TECO Guatemala.

On Sept. 28, 2012, TECO Energy announced that its international power subsidiary, TECO Guatemala, entered into agreements to sell all of its equity interests in the Alborada and San José power stations, and related solid fuel handling and port facilities in Guatemala, for a total purchase price of $227.5 million in cash. On Dec. 19, 2012, the sale closed on the San José Power Station and related facilities and operations for a price of $215.0 million (see **Note 19** to the **TECO Energy Consolidated Financial Statements)**. The sale of the Alborada Power Station closed on Sept. 27, 2012, for a price of $12.5 million.

The 2012 losses in discontinued operations of $33.3 million reflect the results from operations of $18.2 million for the generating plants in Guatemala through the closing of the sales, a $28.6 million loss on assets sold including transaction costs, and a $22.9 million charge associated with foreign tax credit write offs.

On Jan. 13, 2009, TECO Guatemala Holdings, LLC's (TGH), a wholly-owned subsidiary of TECO Energy.) delivered a Notice of Intent to the Guatemalan government that it intended to file an arbitration claim against the Republic of Guatemala under the Dominican Republic Central America – United States Free Trade Agreement (DR – CAFTA) alleging a violation of fair and equitable treatment of its investment in EEGSA. On Oct. 20, 2010, TGH filed a Notice of Arbitration with the International Centre for Settlement of Investment Disputes (ICSID) to proceed with its arbitration claim. While TECO Energy and its subsidiaries no longer have assets or operations in Guatemala, TGH has retained its rights under this claim.

TGH filed the arbitration claim with ICSID in 2010, alleging a violation of fair and equitable treatment of its investment in Empresa Eléctrica de Guatemala, S.A. (EEGSA), the largest private distribution company in Central America. TGH's investment was sold on Oct. 21, 2010. The arbitration was prompted by actions of the Guatemalan government in July 2008, which, among other things, unilaterally reset the distribution tariff for EEGSA at levels well below the tariffs in effect at the time that the distribution tariff was reset.

On Dec. 19, 2013, the ICSID tribunal hearing TGH's arbitration claim against the Republic of Guatemala issued an award in the case. The ICSID tribunal found that Guatemala breached its treaty obligation to grant TGH fair and equitable treatment under the terms of the DR-CAFTA, thereby causing damages to TGH for which it is entitled to compensation. In sum, the tribunal found that Guatemala's repudiation of fundamental regulatory principles applying to the tariff review process was arbitrary and breached elementary standards of due process in administrative matters.

The ICSID tribunal unanimously found in favor of TGH and awarded damages of approximately U.S. $21.1 million, plus interest from Oct. 21, 2010, at a rate equal to the prime rate plus 2%. In addition, the tribunal ruled that Guatemala must reimburse TGH for approximately $7.5 million of the costs it incurred in pursuing the arbitration.

Pursuant to ICSID's rules and procedures, each party has 120 days after the date of the award to file an application for its annulment. Pending the outcome of a potential annulment filing, results in 2013 do not reflect any benefit of this decision.

OTHER ITEMS IMPACTING NET INCOME

Other Income (Expense)

Other income (expense) of $9.9 million in 2013 and of $10.8 million in 2012 included miscellaneous services at the utilities such as lightning surge protection equipment, royalties for coal mined on properties leased by TECO Coal and from the sale of assets no longer in service.

AFUDC equity at Tampa Electric, which is included in Other income (expense), was $6.3 million, $2.6 million and $1.0 million in 2013, 2012 and 2011, respectively. AFUDC is expected to increase in 2014 due to the construction of a reclaimed water pipeline to the Polk Power Station and spending related to the Polk Units 2 – 5 conversion project (see the **Liquidity, Capital Resources** section).

Interest Expense

In 2013, interest expense was $166.9 million compared to $183.5 million in 2012 and $197.4 million in 2011. In 2013, interest expense decreased due to lower debt balances and lower interest rates on debt at TEC as a result of refinancing activities in 2012 (see **Financing Activity** section). Interest expense also declined due to an FPSC-approved lower interest rate paid on customer deposits at the utilities, effective in August 2012.

Interest expense is expected to increase in 2014, primarily due to increased borrowing at Tampa Electric to support the construction of the Polk Power Station Units 2 – 5 conversion.

Income Taxes

The provision for income taxes decreased in 2013, primarily due to lower operating income. The provision for taxes was higher in 2012, primarily due to higher operating income and state income taxes. Income tax expense as a percentage of income from continuing operations before taxes was 35.5% in 2013, 35.9% in 2012 and 36.3% in 2011. We expect our 2014 annual effective tax rate to be approximately 37.0%.

The cash payments for federal income taxes, as required by the federal AMT rules, state income taxes, foreign income taxes and payments (refunds) related to prior years' audits totaled $1.8 million, $7.2 million and $9.4 million in 2013, 2012 and 2011, respectively.

Due to the NOL carryforward position resulting from the disposition of the generating assets formerly held by, our merchant power subsidiary, cash tax payments for income taxes are limited to approximately 10% of the AMT rate. We expect future cash tax payments to be limited to a similar level and various state taxes. As a result of bonus depreciation, enacted under economic stimulus legislation since 2008, and tax repair technical guidance and regulations released in 2013, we currently project to utilize these NOL carryforwards primarily in the 2015 through 2018 period. Beginning with 2018, we also expect to start using more than $213 million of AMT carry-forward to limit future cash tax payments for federal income taxes to the level of AMT. We currently project minimal cash tax payments over the next five years.

The utilization of the NOL and AMT carryforwards are dependent on the generation of sufficient taxable income in future periods.

For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective tax rate, see **Note 4** to the **TECO Energy Consolidated Financial Statements**.

LIQUIDITY, CAPITAL RESOURCES

The table below sets forth the Dec. 31, 2013 consolidated liquidity and cash balances, the cash balances at the operating companies and TECO Energy parent, and amounts available under the TECO Energy/Finance and TEC credit facilities.

Balances as of Dec. 31, 2013

(millions)	**Consolidated**	**Tampa Electric Company**	**Unregulated Companies**	**Parent**
Credit facilities	$ 675.0	$ 475.0	$ --	$ 200.0
Drawn amounts/LCs	84.7	84.7	--	--
Available credit facilities	590.3	390.3	--	200.0
Cash and short-term investments	185.2	9.8	3.6	171.8
Total liquidity	$775.5	$400.1	$3.6	$371.8

In 2013, we met our cash needs primarily from internal sources. Cash from operations was $659 million. We paid dividends of $191 million in 2013, and capital expenditures were $532 million. We reduced long-term debt by $52 million, which represents Tampa Electric's purchase in lieu of redemption of HCIDA Pollution Control Revenue Refunding Bond***s***. TEC supplemented its cash needs in 2013 with moderate use of its credit facility under which $85 million was drawn at year end.

In 2012, we also met our cash needs primarily from internal sources. Cash from operations was $757 million. We paid dividends of $190 million in 2012, and capital expenditures were $505 million. Other sources of cash included $194 million of net sale proceeds, primarily from the sale of our ownership interest in TECO Guatemala (see **Discontinued Operations**). We reduced long-term debt by $101 million, which included the retirement of $34 million of San José project debt with its sale, $9 million of TECO Energy parent debt and the net effect of TEC refinancing activities. There was no short-term debt outstanding at year-end 2012.

Cash from Operations

In 2013, consolidated cash flow from operations was $659 million. The lower cash from operations in 2013 was primarily the result of lower operating results from TECO Coal and the absence of operating cash flows from TECO Guatemala, which was sold at the end of 2012. The 2013 cash from operations reflects pension contributions of $40 million. In 2012, consolidated cash flow from operations was $757 million. Although the timing of recoveries, particularly fuel and purchased power, under FPSC-approved cost-recovery clauses can have a significant impact on cash from operations in any one year, in 2012 the net impact was only $9 million. We had anticipated a more significant impact as the 2012 FPSC-approved clause rates provided for refunds of previous over-recoveries; however, lower than expected actual fuel prices resulted in a net over-recovered balance at the end of 2012. The 2012 cash from operations reflects pension contributions of $37 million.

We made minimal cash payments for state and federal income taxes in 2013 (see the **Income Taxes** section). Bonus depreciation, enacted under economic stimulus legislation annually since 2008, has significantly reduced federal taxable income at Tampa Electric and PGS. We file a consolidated tax return, and under our tax sharing agreements, each subsidiary's tax payment is determined on a standalone basis. Significant NOL carryforwards are available at TECO Energy parent that can be used to offset taxable income in the consolidated return such that cash payments for federal income taxes are limited to approximately 10% of the AMT rate. During the period of bonus depreciation, taxable income has been reduced significantly by the bonus deductions, and as a result we have utilized our NOL carryforwards less than expected in recent years. TECO Energy parent cash flows have therefore been less than expected through this period, and our projections for the full utilization of the NOL carryforwards has been extended to 2018. Tampa Electric and PGS have realized higher cash flows in recent years as a result of reduced taxes from bonus depreciation, which has supported their capital spending programs. While 2014 will be the final year available for bonus depreciation deductions, we expect that Tampa Electric and PGS will continue to realize significant cash tax savings as a result of the IRS technical guidance on repair deduction for generation activities and Tangible Capitalization Regulations issued in 2013, and that TECO Energy parent will realize the cash benefit of the NOL carryforwards primarily in the 2015 through 2018 period.

We expect cash from operations to increase in 2014, driven by higher operating results primarily at Tampa Electric, net of somewhat lower net recoveries under various regulatory clauses. In November 2013, the FPSC approved fuel-adjustment and other recovery clause rates that provide for refunds to customers of estimated 2013 net over-recoveries of fuel and purchased power over 12 months beginning Jan. 1, 2014 (see the **Regulation** section).

Cash from Investing Activities

Our investing activities in 2013 resulted in a net use of cash of $522 million, which reflects capital expenditures totaling $532 million.

We expect capital spending for the next several years to be above 2013 levels, primarily due to generating capacity additions at Tampa Electric (see the **Capital Expenditures** section).

Cash from Financing Activities

Our financing activities in 2013 resulted in a net use of cash of $152 million. Tampa Electric purchased in lieu of redemption $52 million of HCIDA Pollution Control Revenue Refunding Bonds (see the **Financing Activity** section) and borrowed $84 million under its credit facility. We paid $191 million in common stock dividends, and we received $7 million from exercises of stock options.

Financing Activities Related to the NMGC Acquisition

In 2014, we expect to finance the acquisition of NMGC with a mix of cash on hand at TECO Energy parent, the issuance of $350 to $400 million of TECO Energy common stock, and the issuance of $50 million of debt at the NMGC level and $200 million of debt at the NMGI level primarily to repay existing debt upon closing. We expect to issue the debt and issue the new shares close to the time of closing the transaction, which is expected in the third quarter of 2014; however the terms and conditions of the financing transactions are unknown at this time.

Credit Facility Related to NMGC

In connection with the pending acquisition of NMGC, on Dec. 17, 2013, TECO Energy entered into a $125 million bank credit facility (the "NMGC Credit Agreement"). TECO Energy has no rights or obligations to borrow under the NMGC Credit Agreement, which it has entered into solely with the intent of it being assigned to, and assumed by, NMGC upon the closing of the acquisition. Pursuant to the terms of the NMGC Credit Agreement, upon such closing, TECO Energy will designate NMGC as the borrower under the NMGC Credit Agreement and TECO Energy's obligations under the terms of the NMGC Credit Agreement will terminate (see **Note 22** to the **TECO Energy Consolidated Financial Statements).**

TECO Finance Bridge Facility Related to NMGC

In June 2013, TECO Energy and TECO Finance entered into a $1.075 billion Senior Unsecured Bridge Credit Agreement (Bridge Facility). The Bridge facility is sized to cover the $950 million purchase price and provide a $125 million credit facility for the operations of NMGC (see **Note 22** to the **TECO Energy Consolidated Financial Statements).**

Cash and Liquidity Outlook

In general, we target consolidated liquidity (unrestricted cash on hand plus undrawn credit facilities) of at least $500 million. At Dec. 31, 2013, our consolidated liquidity was $775 million, consisting of $400 million at TEC, $372 million at TECO Energy parent, and $4 million at the other companies.

We expect our sources of cash in 2014 to include cash from operations at levels above 2013, due in large part to higher net income from the regulated Florida operating companies, and long-term debt issuance of $250 - $300 million at TEC. We plan to use cash in 2014 to fund capital spending estimated at $720 million, to pay dividends to shareholders, and the repayment of $83 million of maturing Tampa Electric debt.

We expect to continue to make equity contributions to TEC in 2014 in order to support the utilities capital structure and financial integrity. TEC expects to fund its capital needs with a combination of internally generated cash and equity contributions from us, and we anticipate that these contributions will total $150 million in 2014.

Our goal is to reduce leverage at TECO Finance over time as we are able to utilize our NOL carryforwards and as the equity needs of Tampa Electric normalize after the peak capital spending expected over the next several years during the Polk combined cycle conversion project (see the **Capital Expenditures** section). Our long-term debt maturities for TECO Finance total $191 million in 2015, $250 million in 2016, $300 million in 2017 and $300 million in 2020.

TEC expects to utilize cash from operations and equity contributions from TECO Energy to support its capital spending program, supplemented with incremental long-term debt and utilization of its credit facilities to maintain strong utility capital structures. Our credit facilities contain certain financial covenants (see **Covenants in Financing Agreements** section). Although we expect the normal utilization of our credit facilities to be low, we estimate that we could fully utilize the total available capacity under our facilities in 2014 and remain within the covenant restrictions.

Our expected cash flow could be affected by variables discussed in the individual operating company sections, such as customer growth, weather and usage changes at our regulated businesses, and coal margins. In addition, actual fuel and other regulatory clause net recoveries will typically vary from those forecasted; however, the 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 (see the **Risk Factors** section).

As a result of our significant reduction of parent debt, and reduced business risk, we have improved our debt credit ratings in recent years (see **Credit Ratings** section). In the unlikely event TEC's ratings were downgraded to below investment grade, counterparties to our derivative instruments could request immediate payment or full collateralization of net liability positions. If the credit risk-related contingent features underlying these derivative instruments were triggered as of Dec. 31, 2013, we could have been required to post additional collateral or settle existing positions with counterparties totaling $0.1 million. In addition, credit provisions in long-term gas transportation agreements of Tampa Electric and PGS would give the transportation providers the right to demand collateral, which we estimate to be approximately $63.7 million. None of our credit facilities or financing agreements have ratings downgrade covenants that would require immediate repayment or collateralization.

SHORT-TERM BORROWING

Credit Facilities

At Dec. 31, 2013 and 2012, the following credit facilities and related borrowings existed:

	Dec. 31, 2013			Dec. 31, 2012		
(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(2)	$325.0	$ 6.0	$0.7	$325.0	$ --	$1.5
1-year accounts receivable facility	150.0	78.0	--	150.0	--	--
TECO Energy/TECO Finance :						
5-year facility(2)(3)	200.0	--	--	200.0	--	--
Total	$675.0	$ 84.0	$0.7	$675.0	$ --	$1.5

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

These credit facilities require commitment fees ranging from 12.5 to 25.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at Dec. 31, 2013 was 0.56%. There were no outstanding borrowings as Dec. 31, 2012.

At Dec. 31, 2013, TECO Finance had a $200 million bank credit facility in place guaranteed by TECO Energy with a maturity date in December 2018. TEC had a bank credit facility totaling $325 million, also maturing in December 2018. In addition, TEC had a $150 million accounts receivable securitized borrowing facility that was renewed in February 2014 with a maturity date of Feb. 13, 2015. The TECO Finance and TEC bank credit facilities both include sub-limits for letters of credit of $200 million. At Dec. 31, 2013, the TECO Finance credit facility was undrawn and no letters of credit were outstanding. At Dec. 31, 2013, the outstanding borrowings under the TEC credit facilities were $84 million and $0.7 million of letters of credit were outstanding.

The table below sets forth TECO Finance and TEC maximum, minimum, and average credit facility utilization in 2013.

2013 Credit Facility Utilization

(millions)	Maximum drawn amount	Minimum drawn amount	Average drawn amount	Average interest rate
TECO Finance	$ —	$ —	$ —	—
Tampa Electric Company	$ 84.0	$ —	$ 5.4	0.59%

Significant Financial Covenants

In order to utilize their respective bank credit facilities, TECO Energy, TECO Finance and TEC must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, TECO Finance, TEC, and the other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2013, TECO Energy, TECO Finance, TEC and the other operating companies were in compliance with all applicable financial covenants. The table that follows lists the significant financial covenants and the performance relative to them at Dec. 31, 2013. Reference is made to the specific agreements and instruments for more details.

(millions, unless otherwise indicated)

Instrument	*Financial Covenant*(1)	*Requirement/Restriction*	*Calculation at Dec. 31, 2013*
Tampa Electric Company			
Credit facility(2)	Debt/capital	Cannot exceed 65%	45.7%
Accounts receivable credit facility(2)	Debt/capital	Cannot exceed 65%	45.7%
6.25% senior notes	Debt/capital	Cannot exceed 60%	45.7%
	Limit on liens(3)	Cannot exceed $700	$0 liens outstanding
Insurance agreement relating to certain pollution bonds	Limit on liens(3)	Cannot exceed $483 (7.5% of net assets)	$0 liens outstanding
TECO Energy/TECO Finance			
Credit facility(2)	Debt/capital	Cannot exceed 65%	56.2%
TECO Finance 6.75% notes	Restrictions on secured debt(4)	(5)	(5)

(1) As defined in each applicable instrument.
(2) See **Note 6** to the TECO Energy Consolidated Financial Statements for a description of the credit facilities.
(3) If the limitation on liens is exceeded the company is required to provide ratable security to the holders of these notes.
(4) These restrictions would not apply to first mortgage bonds of Tampa electric if any were outstanding.
(5) 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. At Dec. 31, 2013 neither TECO Energy nor TECO Finance had secured debt outstanding.

Credit Ratings of Senior Unsecured Debt

	Standard & Poor's (S&P)	*Moody's*	*Fitch*
Tampa Electric Company	BBB+	A2	A-
TECO Energy/TECO Finance	BBB	Baa1	BBB

On Jan. 30, 2014, Moody's upgraded the credit ratings of TECO Energy, TECO Finance and TEC. TECO Energy and TECO Finance senior unsecured debt is rated Baa1, up from Baa2, and TEC's senior unsecured debt is rated A2, up from A3, all with stable outlooks.

On May 30, 2013, Fitch placed the rating of TECO Energy, TECO Finance and TEC on ratings watch negative following the announcement of our agreement to purchase NMGC. On Oct. 9, 2013, Fitch removed TEC from ratings watch negative and affirmed its ratings. S&P, 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 S&P is BBB-, for Moody's is Baa3 and for Fitch is BBB-; thus, all three credit rating agencies assign TECO Energy, TECO Finance and TEC's senior unsecured debt investment-grade credit ratings.

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. Our access to capital markets and cost of financing, including the applicability of restrictive financial covenants, are influenced by the ratings of our securities. In addition, certain of TEC's derivative instruments contain provisions that require TEC's debt to maintain investment grade credit ratings (see **Note 12** to the **TECO Energy Consolidated Financial Statements)**. The credit ratings listed above are included in this report in order to provide information that may be relevant to these matters and because downgrades, if any, in credit ratings may affect our ability to borrow and may increase financing costs, which may decrease earnings (see the **Risk Factors** section). These credit ratings are not necessarily applicable to any particular security that we may offer and therefore should not be relied upon for making a decision to buy, sell or hold any of our securities.

Summary of Contractual Obligations

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

Contractual Cash Obligations at Dec. 31, 2013

(millions)	**Payments Due by Period**					
	Total	**2014**	**2015**	**2016**	**2017-2018**	**After 2018**
Long-term debt [1]	$2,923.9	$83.3	$274.5	$333.3	$604.2	$1,628.6
Operating leases/rentals/capacity payments	93.8	19.8	18.8	17.2	24.6	13.4
Net purchase obligations/commitments [2] [3]	412.0	245.6	91.9	30.3	29.0	15.2
Interest payment obligations	1,581.1	155.0	143.3	126.7	209.3	946.8
Pension plan [4]	131.9	34.2	47.7	23.4	13.2	--
Total contractual obligations	$5,142.7	$537.9	$558.7	$540.4	$901.7	$2,604.0

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

(2) The table above excludes payment obligations under contractual agreements of Tampa Electric and PGS for fuel, fuel transportation and power purchases which are recovered from customers under regulatory clauses approved by the FPSC annually (see the Regulation section).

(3) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2013, these commitments include Tampa Electric's outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines.

(4) 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** section and **Note 5** to the TECO Energy **Consolidated Financial Statements**).

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

Contingent Obligations at Dec. 31, 2013

(millions)	**Commitment Expiration**						
		Total[2]	**2014**	**2015**	**2016**	**2017 - 2018**	**After 2018[1]**
Letters of credit		$ 0.7	$ --	$ --	$ --	$ --	$ 0.7
Guarantees	Fuel purchase/energy management [2]	101.8	10.0	--	--	--	91.8
	Fuel sales and transportation	5.5	0.8	0.7	--	--	4.0
	Other	5.0	--	5.0	--	--	--
Total contingent obligations		$113.0	$ 10.8	$ 5.7	$ --	$ --	$96.5

(1) These guarantees renew annually and are shown on the basis that they will continue to renew beyond 2018.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements.

CAPITAL INVESTMENTS

		Forecast			
(millions)	**Actual 2013**	**2014**	**2015**	**2016-2018**	**2014 - 2018 Total**
Tampa Electric					
Transmission	$30	$35	$20	$85	$140
Distribution	115	115	110	355	580
Generation	155	140	125	390	655
New generation and transmission	55	200	245	95	540
Other	30	45	40	75	160
Other environmental	40	65	20	40	125
Tampa Electric total	425	600	560	1,040	2,200
Net cash effect of accruals, retentions and AFUDC	5	--	--	--	--
Tampa Electric net	430	600	560	1,040	2,200
Peoples Gas	80	100	100	295	495
Unregulated companies	20	20	25	100	145
Total	$530	$720	$685	$1,435	$2,840

(1)Individual line items exclude AFUDC-debt and equity; however total AFUDC is a reconciling item in 2013.

TECO Energy's 2013 capital expenditures of $530 million included $425 million at Tampa Electric, including AFUDC debt and equity. Tampa Electric's capital expenditures in 2013 included $28 million for a reclaimed water pipeline to serve the Polk Power Station, approximately $40 million to improve the Big Bend Station solid fuel handling and flue gas desulphurization systems reliability, for equipment and facilities to meet modest customer growth, generating equipment maintenance, and environmental compliance. Capital expenditures for PGS were approximately $80 million, including approximately $28 million for maintenance of the existing system, $36 million to expand the system and support customer growth, and $13 million for replacement of cast iron and bare steel pipe. TECO Coal's capital expenditures included $20 million primarily for normal mining equipment replacement, and the development of new mines to support continued production.

TECO Energy estimates capital spending to be $720 million for 2014 and approximately $2.1 billion during the 2015 to 2018 period. As described below, this forecast includes $540 million for Tampa Electric's next increment of generation expansion, including transmission system improvements to support the increased plant output.

For 2014, Tampa Electric expects to spend $600 million. For the transmission and distribution systems, Tampa Electric expects to spend $150 million in 2014, including approximately $110 million for normal transmission and distribution system expansion and reliability, and approximately $40 million for transmission and distribution system storm hardening. Capital expenditures for the existing generating facilities of $140 million include approximately $20 million for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, approximately $100 million for generating unit outages in 2014 and advance purchases for 2015 unit outages, $10 million for a reclaimed water pipeline to eliminate ground water usage at the Polk Power Station, and $10 million for the conversion of distillate oil igniters to natural gas. In addition, Tampa Electric expects to spend $65 million for environmental compliance programs and improvements to environmental control equipment in 2014 including approximately $45 million to improve the Big Bend Station solid fuel handling system reliability.

In the 2015 to 2018 period, Tampa Electric expects to spend approximately $315 million annually to support normal system growth and reliability, environmental compliance and improvements to computer systems to serve customers. This level of ongoing capital expenditures reflects the costs for materials and contractors, 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 programs and requirements include: approximately $20 million annually for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, average annual expenditures of almost $110 million to support generating unit availability and reliability; average annual expenditures of $15 million for environmental compliance; average annual expenditures of more than $30 million for general infrastructure and facilities; average annual expenditures of approximately $25 million for transmission and distribution system storm hardening; approximately $115 million annually for transmission and distribution system capacity improvements to meet expected customer growth and reliability.

Tampa Electric's forecast for capital spending does not include amounts that may be spent on projects that would result in the generation of additional revenues. Spending on any projects would be justified by an economic analysis that demonstrates a net benefit.

Tampa Electric's capital spending forecast includes amounts related to the conversion of the Polk Units 2 – 5 from peaking service to combined cycle with a January 2017 in-service date. The determination of need was approved by the FPSC in December 2012, the final site certification approval by the FDEP was received in the fourth quarter of 2013, and the final air emissions permits were received in January 2014. Construction commenced in January 2014. The capital expenditures for the conversion and the related transmission system improvements to support the additional generating capacity are included in the "New generation and transmission" line in the **Capital Investments** table above. The peak capital spending is forecast at $445 million for both the transmission system and plant conversions in the 2014 and 2015 periods.

Capital expenditures for PGS are expected to be about $100 million in 2014 and $395 million during the 2015 to 2018 period. Included in these amounts is an average of approximately $50 million annually for projects associated with customer growth and system expansion. The remainder represents capital expenditures for ongoing renewal, replacement and system safety, including approximately $12 million annually for the replacement of cast iron and bare steel pipe, which is recovered through a rider clause approved by the FPSC in 2012 (see the **Regulation** section).

At PGS, higher capital expenditures are focused on extending the system to serve large commercial or industrial customers that are currently using petroleum and propane as fuel under multi-year contracts. The current natural gas prices and the projections that natural gas prices are going to remain low into the future makes it attractive for these customers to convert from fuels that are currently three to four times more expensive on a cost per MMBTU basis.

The unregulated companies expect to invest $20 million in 2014, primarily for normal mining equipment replacement at TECO Coal. The unregulated companies expect to spend $125 million during the 2015 – 2018 period, primarily for coal mine development to maintain production, compliance with new safety requirements under the MINER Act, and for normal coal mining equipment renewal and replacement at TECO Coal.

The capital expenditure forecast beyond 2014 does not include additional investment to develop the metallurgical coal reserves that TECO Coal announced in November 2011. Based on current market conditions, TECO Coal does not expect to make additional investments to develop these reserves until metallurgical coal prices improve to a level to support that investment. In 2012, TECO Coal obtained the necessary permit amendments from the state of Kentucky related to surface development activities to access these reserves, and further evaluated detailed mining plans and potential markets for this high-volatile metallurgical coal. TECO Coal completed utility relocation and preliminary surface work to bring these reserves into production. Based on previous estimates, subject to development of final plans, the cost to develop these reserves is estimated to be approximately $160 million over approximately a three year period.

If the U.S. Congress or the Florida Legislature enacted a national or Florida RPS, additional capital spending for renewable generating resources to meet the requirements of an RPS would likely be needed (see the **Environmental Compliance** section). Depending on the final federal or state rules, Tampa Electric may need to invest capital to develop additional sources of renewable power generation.

The forecast of capital expenditures shown above is based on our current estimates and assumptions for normal maintenance capital at the operating companies; capital expenditures to support normal system reliability and growth at Tampa Electric and PGS; the replacement of cast iron and bare steel pipe at PGS; the programs for transmission and distribution system storm hardening and transmission system reliability requirements; generating capacity expansion at Tampa Electric and incremental investments above normal maintenance capital to expand the PGS system and production 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).

Financing Activity

Our year-end 2013 consolidated capital structure was 56% debt and 44% common equity. The debt-to-total-capital ratio has improved significantly over the past six years, primarily due to the repayment of more than $1.0 billion of parent and parent guaranteed debt, consisting of $779 million in 2007, a net $189 million in 2010, $64 million in 2011, and $9 million in 2012, as well as the increase in retained earnings. At Dec. 31, 2013, Tampa Electric's year-end capital structure was 45% debt and 55% common equity.

In 2013 and 2012, we raised $6.7 million and $3.9 million, respectively, of equity, primarily through the exercise of stock options.

On Sept. 3, 2013, Tampa Electric purchased in lieu of redemption $51.6 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 B (the Series 2007 B HCIDA Bonds). On Mar. 26, 2008, the HCIDA had remarketed the Series 2007 B HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2007 B HCIDA Bonds bore interest at a term rate of 5.15% per annum from March 26, 2008 to Sept. 1, 2013. Tampa Electric is responsible for payment of the interest and principal associated with the Series 2007 B HCIDA Bonds.

On Dec. 5, 2012, TECO Energy redeemed $8.8 million of 6.75% Notes due May 15, 2015. The redemption price was equal to $1,141.86 per $1,000 principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date. In connection with this transaction, $0.8 million of premiums were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income and as part of the "Cash flows from operating activities" in the Consolidated Statements of Cash Flows for 2012.

On Oct. 1, 2012, Tampa Electric redeemed $147.1 million of HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Project), Series 2002 due Oct. 1, 2013 and Oct. 1, 2023 (2002 Bonds) at a redemption price equal to 100% of the principal amount of the 2002 Bonds to be redeemed, plus accrued and unpaid interest to Oct. 1, 2012. Before the optional redemption, the $60.7 million of 2002 Bonds due Oct. 1, 2013 bore interest at 5.10% and the $86.4 million of 2002 Bonds due Oct. 1, 2023 bore interest at 5.50%.

On Sept. 28, 2012, TEC completed an offering of $250 million aggregate principal amount of 2.60% Notes due 2022. The 2.60% Notes were sold at 99.878% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $247.7 million. Net proceeds were used to repay the 2002 Bonds. The remaining net proceeds were used to repay short-term debt and for general corporate purposes. At any time prior to June 15, 2022, TEC may redeem all or any part of the 2.60% Notes at its option at a redemption price equal to the greater of (i) 100% of the principal amount of 2.60% Notes to be redeemed or (ii) the sum of the present values of the remaining payments of principal and interest on the 2.60% Notes to be redeemed, discounted to the redemption date on a semiannual basis at an applicable treasury rate, plus 15 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after June 15, 2022, TEC may at its option redeem the 2.60% Notes, in whole or in part, at 100% of the principal amount of the 2.60% Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

On June 5, 2012, TEC completed an offering of $300 million aggregate principal amount of 4.10% Notes due 2042. The 4.10% Notes were sold at 99.724% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, and estimated offering expenses and before settlement of interest rate swaps) of approximately $296.2 million. Net proceeds were used to repay maturing long-term debt, to repay short-term debt and for general corporate purposes. At any time prior to Dec. 15, 2041, TEC may redeem all or any part of the 4.10% Notes at its option and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of 4.10% Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the 4.10% Notes to be redeemed, discounted at an applicable treasury rate, plus 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Dec. 15, 2041, TEC may at its option redeem the 4.10% Notes, in whole or in part, at 100% of the principal amount of the 4.10% Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

On March 15, 2012, Tampa Electric purchased in lieu of redemption $86 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (the $86 million Bonds). On March 19, 2008, the HCIDA remarketed the $86 million Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The $86 million Bonds bore interest at a term rate of 5.00% per annum from March 19, 2008 to March 15, 2012. Tampa Electric is responsible for payment of the interest and principal associated with the $86 million Bonds. Regularly scheduled principal and interest payments, when due, are insured by Ambac Assurance Corporation.

On Sept. 27, 2012, TECO Energy announced that its international power subsidiary, TECO Guatemala, entered into agreements to sell all of the equity interests in the Alborada and San José power stations and related facilities and operations in Guatemala. The sale of the Alborada Power Station closed on Sept. 27, 2012, for a selling price of $12.5 million. The sale of the San José Power Station and related facilities and operations in Guatemala closed on Dec. 19, 2012 for a price of $215.0 million. TECO Energy utilized $25.3 million of the proceeds to repay the San José Power Station project debt at closing (see **Discontinued Operations** section and **Note 19** 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.

Deferred Income Taxes

We use the asset and liability method in the measurement of deferred income taxes. Under the asset and 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 the entire 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, 2013, we had a net deferred income tax liability of $343.7 million, attributable primarily to property-related items, AMT credit carry forwards and operating loss carry forwards. Based primarily on historical income levels and the company's expectations for steady future earnings growth, management has determined that the deferred tax assets associated with operating losses and AMT credit carryforwards recorded at Dec. 31, 2013, 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, both operating and capital, 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.

The FASB has guidance that 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 uncertainty in income taxes and other tax items in **Note 4** to the **TECO Energy Consolidated Financial Statements**.

Employee Postretirement Benefits

TECO Energy sponsors a defined benefit pension plan (pension plan) that covers substantially all employees. In addition, the company has an unfunded non-qualified, non-contributory supplemental executive retirement benefit plan available to certain members of 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, salary increases and discount rates. These factors are determined by the company within certain guidelines and with the help of external consultants. The company considers market conditions, including changes in investment returns and interest rates, in making these assumptions.

The company believes that the accounting related to employee postretirement benefits is a critical accounting estimate for the following reasons: 1) a change in the estimated benefit obligation could have a material impact on reported assets, AOCI and results of operations; and 2) changes in assumptions could change the annual pension funding requirements, having a significant impact on the company's annual cash requirements.

Pension plan assets (plan assets) are invested in a mix of equity and fixed-income securities. 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 the company's portfolio, with provision for active management and expenses paid from the trust. The discount rate assumption used to determine the 2013 benefit expense and Dec. 31, 2013, benefit obligation was based on a cash flow matching technique developed by the company's outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement dates to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate. The compensation 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% decrease in the assumed rate of return on plan assets would have increased 2013 after-tax pension cost by approximately $3.1 million. Likewise, a 1% decrease in the discount rate assumption would have increased 2013 after-tax pension cost approximately $2.8 million. For 2014, a 1% decrease in the discount rate assumption would result in an approximately $1.6 million after-tax increase in the expected pension cost. A 1% decrease in the assumed rate of return on plan assets would result in an approximately $3.5 million after-tax increase in expected pension cost.

Unrecognized actuarial gains and losses for the pension plan are being recognized over a period of approximately 12 years, 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 applicable accounting guidance for pensions. The company's policy is to fund the plan based on the required contribution determined by its actuaries within the guidelines set by the ERISA, as amended.

In July 2012, the president signed into law the MAP-21. MAP-21 provides funding relief for pension plan sponsors by stabilizing discount rates used in calculating the required minimum pension contributions and increasing PBGC premium rates to be paid by plan sponsors. The company expects the required minimum pension contributions to be lower than the levels previously projected; however, the company plans on funding at levels above the required minimum pension contributions under MAP-21.

In addition, the company currently provides certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 who meet certain service requirements. In March 2010, the Patient Protection and Affordable Care Act and a companion bill, the Health Care and Education Reconciliation Act, combined the Health Care Reform Acts, were signed into law. Among other things, both acts reduce the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, TECO Energy reduced its deferred tax asset by recording a corresponding charge and a regulatory tax asset in the first quarter of 2010 and recorded a true-up of the deferred tax asset in the fourth quarter of 2012. The company implemented an EGWP for its post-65 retiree prescription drug plan effective Jan. 1, 2013. The EGWP is a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduces net periodic benefit cost by taking advantage of rebate and discount enhancements provided under the Health Care Reform Acts. As a result, the company no longer receives Medicare Part D subsidy payments beginning with the 2013 plan year.

The Health Care Reform Acts contain other provisions that may impact TECO Energy's obligation for retiree medical benefits. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase its postretirement benefit obligation. TECO Energy will continue to monitor and assess the impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

The key assumptions used in determining the amount of obligation and expense recorded for postretirement benefits other than pension (OPEB), under the applicable accounting guidance, include the assumed discount rate and the assumed rate of increases in future health care costs. Since 2009 the company has determined the discount rate for the OPEB using that individual plan's projected benefit cash flow rather than using the same discount rate that was determined for the pension plan. In estimating the health care cost trend rate, the company considers its actual health care cost experience, future benefit structures, industry trends, and advice from its outside actuaries. The company assumes 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.

The assumed health care cost trend rate for medical costs was 7.50% in 2013 and decreases to 4.50% in 2025 and thereafter. A 1% increase in the health care trend rates would have produced a $0.2 million after-tax increase in the aggregate service and interest cost for 2013, and a $6.8 million increase in the accumulated postretirement benefit obligation as of Dec. 31, 2013.

The actuarial assumptions used in determining the company's 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 the company believes that the assumptions used are appropriate, differences in actual experience or changes in assumptions may materially affect the company's financial position or results of operations.

See the discussion of employee postretirement benefits in **Note 5** to the **TECO Energy Consolidated Financial Statements**.

Evaluation of Assets for Impairment

In accordance with accounting guidance for long-lived assets, the company assesses whether there has been an impairment of its long-lived assets and certain intangibles held and used when such indicators exist. The company normally reviews 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. However, in the case of a triggering event, such as a significant market disruption or sale of a business, the values of related long-lived assets are reviewed. 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. The company's 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.

See **Note 20** to the **TECO Energy Consolidated Financial Statements** for discussion of the company's treatment of impairment of long-lived assets for the year ended Dec. 31, 2013.

Regulatory Accounting

Tampa Electric's and PGS's retail businesses and the prices charged to customers are regulated by the FPSC. Tampa Electric's wholesale business is regulated by the FERC. As a result, the regulated utilities qualify for the application of accounting guidance for certain types of regulation. This guidance 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 GAAP 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.

As a result of regulatory treatment and corresponding accounting treatment, we expect that the impact on utility costs and required investment associated with future changes in environmental regulations would create regulatory assets. Current regulation in Florida allows utility companies to recover from customers prudently incurred costs (including, for required capital investments, depreciation and a return on invested capital) for compliance with new environmental regulations through the ECRC (see the **Environmental Compliance** and **Regulation** sections).

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. We believe the application of regulatory accounting guidance is a critical accounting policy since 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

Unrecognized Tax Benefits

In July 2013, the FASB issued guidance regarding the presentation of unrecognized tax benefits in the statement of position when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. It requires that an unrecognized tax benefit be presented as a reduction to a deferred tax asset for net operating loss carryforwards, similar tax losses or tax credit carryforwards, with certain exceptions. The guidance is effective for interim and annual reporting periods beginning on or after Dec. 15, 2013. The guidance will have no effect on the company's results of operations, financial position or cash flows.

Comprehensive Income

In February 2013, the FASB issued guidance requiring improved disclosures of significant reclassifications out of AOCI and their corresponding effect on net income. The guidance is effective for interim and annual reporting periods beginning on or after Dec. 15, 2012. The company has adopted this guidance as required. It has no effect on the company's results of operations, financial position or cash flows.

INFLATION

The effects of general inflation on our results have not been significant for the past several years. The annual average rate of inflation, as measured by the CPI-U, as reported by the U.S. Department of Labor, was 1.5% in 2013 after a 1.7% increase in 2012, and a 3.0% increase in 2011. This is lower than the 2.4% average annual increase over the past ten years. This is the first time the CPI has gone up less than 2.0% for consecutive years since 1997-98.

The current economic outlook and the pace of economic recovery have caused the outlook for inflation in 2014 to be higher than in 2013, but lower than in 2011, when oil and commodity prices rose sharply. Reports published by the Federal Reserve Bank of Chicago and others indicate that CPI-U has been below desired levels and is expected to be less than 2.0% in 2014.

ENVIRONMENTAL COMPLIANCE

Environmental Matters

Our businesses have significant environmental considerations. Tampa Electric operates stationary sources with air emissions regulated by the Clean Air Act, and material Clean Water Act implications and impacts by federal and state legislative initiatives. TEC, through its Tampa Electric and PGS divisions, is a PRP for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. Additionally, TECO Coal has considerations concerning wastewater management and environmental permitting.

Air Quality Control
Emission Reductions

Tampa Electric has undertaken major steps to dramatically reduce its air emissions through a series of voluntary actions, including technology selection (e.g., IGCC) and conversion of coal-fired units to natural-gas fired combined cycle; implementation of a responsible fuel mix taking into account price and reliability impacts to its customers; a substantial capital expenditure program to add BACT emissions controls; implementation of additional controls to accomplish early reductions of certain emissions; and enhanced controls and monitoring systems for certain pollutants.

Tampa Electric, through voluntary negotiations in 1999 with the EPA, the U.S. Department of Justice and the FDEP, signed a Consent Decree and Consent Final Judgment, as settlement of federal and state litigation to dramatically decrease emissions from its power plants. Tampa Electric has fulfilled the obligations of the Consent Decree, and the court terminated the Consent Decree on Nov. 22, 2013. Termination of the Consent Final Judgment is in progress and is expected to be completed during the first half of 2014.

The emission reduction requirements of these agreements resulted in the repowering of the coal-fired Gannon Power Station to natural gas, which was renamed as the H. L. Culbreath Bayside Power Station (Bayside Power Station), enhanced availability of flue-gas desulfurization systems (scrubbers) at Big Bend Station to help reduce SO_2, and installation of SCR systems for NO_x reduction on Big Bend Units 1 through 4. Cost recovery for the SCRs began for each unit in the year that the unit entered service through the ECRC (see the **Regulation** section).

As a result of the actions taken under the consent decree, emissions of all pollutant types have been significantly reduced. Since 1998, Tampa Electric has reduced annual SO_2, NO_x and PM emissions from its facilities by 164,000 tons (94%), 63,000 tons (91%) and 4,500 tons (87%), respectively.

Reductions in mercury emissions also have occurred due to the repowering of the Gannon Power Station to the Bayside Power Station. At the Bayside Power Station, where mercury levels have decreased 99% from 1998 levels, there are virtually zero mercury emissions. Additional mercury reductions have been achieved from the installation of the SCRs at Big Bend Power Station, which have led to a system-wide reduction of mercury emissions of more than 90% from 1998 levels.

CAIR/CSAPR

As a result of all its completed emission reduction actions, Tampa Electric has achieved emission reduction levels called for in Phase I and Phase II of CAIR. In July 2008, the U.S. Court of Appeals for the District of Columbia Circuit vacated CAIR on emissions of SO_2 and NO_x. The federal appeals court reinstated CAIR in December 2008 as an interim solution. In July 2011, the EPA issued the final CAIR replacement rule, called the CSAPR. The final CSAPR focused on reducing SO_2 and NO_x in 27 eastern states that contribute to ozone and/or fine particle pollution in other states. Compliance with CSAPR, which would be measured at the individual power plant level, would require the addition of scrubbers or SCRs on most coal-fired power plants. In addition, the rule utilized intrastate emissions allowance trading and limited interstate emissions allowance trading to achieve compliance. All of Tampa Electric's conventional coal-fired units are already equipped with scrubbers and SCRs, and the Polk Unit 1 IGCC unit removes SO_2 in the gasification process.

The EPA has estimated that the implementation of CSAPR would result in the retirement of primarily, smaller, older coal-fired power stations that do not currently have state-of-the-art air pollution control equipment already installed. The retirement of these units or switching to other fuels for compliance with this rule is likely to reduce overall demand for coal, which could reduce sales at TECO Coal.

On Dec. 30, 2011, the U.S. Court of Appeals for the District of Columbia Circuit granted the motion to stay the implementation of CSAPR in all aspects, which had been scheduled to take effect Jan. 1, 2012, and ordered the reinstatement of CAIR pending the outcome of the litigation. On Aug. 21, 2012, the court vacated the rule entirely and remanded it back to the EPA while leaving the CAIR in place. In January 2013, the Court of Appeals rejected the request for a rehearing. On June 24, 2013, the U.S. Supreme Court granted the United States' and environmental group petitions asking the Court to review the D.C. Circuit's decision. EPA has announced that it intends to propose a new rule to address Clean Air Act requirements to reduce the interstate transport of ozone by October 2014. The rule would replace parts of CSAPR, which the U.S. Court of Appeals for the District of Columbia struck down in 2012. EPA acknowledges that the proposal could be influenced by the outcome of the CSAPR appeal to the U.S. Supreme Court.

Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT)

The EPA published proposed rules under National Emission Standards for HAPS on May 3, 2011, pursuant to a court order. These rules are expected to reduce mercury, acid gases, organics, and certain non-mercury metals emissions and require MACT. The final Utility MACT rules, now called Mercury Air Toxics Standards (MATS), were published in December 2011 with implementation called for in early 2015 with extensions to early 2016 or 2017 under certain specific criteria. A potential outcome of the MATS rule is the retirement of smaller, older coal-fired power plants that do not already have emissions controls installed.

All of Tampa Electric’s conventional coal-fired units are already equipped with scrubbers and SCRs, and the Polk Unit 1 IGCC unit emissions are minimized in the gasification process. Tampa Electric is uniquely positioned to be able to meet the new standards without considerable impacts, compared to others who have not taken similar early actions. Therefore, Tampa Electric expects the co-benefits of these control devices for mercury removal to minimize the impact of this rule and expects that it will be in compliance with MATS with nominal additional capital investment.

The retirement of coal-fired generating units as a result of the implementation of this rule could reduce demand for sales at TECO Coal.

Carbon Reductions and GHG

Tampa Electric has 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 20%, bringing emissions to near 1990 levels. Tampa Electric expects emissions of CO_2 to remain near 1990 levels until the addition of the next base load unit, which is scheduled to be in service in January 2017 (see the **Tampa Electric** and **Capital Expenditures** sections). Tampa Electric estimates that the repowering to natural gas and the shut-down of the Gannon Station coal-fired units resulted in an annual decrease in CO_2 emissions of approximately 4.8 million tons below 1998 levels. During this same time frame, the numbers of retail customers and retail energy sales have risen by approximately 30% and 15%, respectively.

Tampa Electric’s power plants currently emit approximately 16 million tons of CO_2 per year. Assuming a projected long-term average annual load growth of more than 1.0%, Tampa Electric could emit approximately 17 million tons of CO_2 (an increase of approximately 6%) by 2020 if natural gas-fired peaking and combined-cycle generation additions are used to meet customer demand.

In 2010, the EPA issued its Final Rule on the mandatory reporting of GHGs, requiring facilities that emit 25,000 metric tons or more of CO_2, or its equivalent, per year to begin collecting GHG data under a new reporting system on Jan. 1, 2010, with the first annual report due Sept. 28, 2011. Tampa Electric complied with the mandatory reporting requirement, in large part through the methods and procedures already utilized and continues to submit annual reports as required. The rule also required natural gas distribution, underground coal mining facilities, and electric transmission and distribution companies, including PGS, TECO Coal and Tampa Electric, that emit 25,000 metric tons or more of CO_2, or its equivalent, per year to begin collecting GHG data under a new reporting system on Jan. 1, 2011, with the first annual report due Sept. 28, 2012. Tampa Electric complied with the reporting requirement and continues to submit annual reports as required.

In December 2009, the EPA published the final Endangerment Finding in the Federal Register. Although the finding was technically made in the context of GHG emissions from new motor vehicles and did not, in itself, impose any requirements on industry or other entities, EPA claims that the finding triggered GHG regulation of a variety of sources under the Clean Air Act (CAA). Related to utility sources, the EPA’s “tailoring rule,” which addresses the GHG emission threshold triggers that would require permitting review of new and/or major modifications to existing stationary sources of GHG emissions, became effective Jan. 2, 2011. While this rule does not have an immediate impact on Tampa Electric’s ongoing operations, GHG permitting was recently completed for Tampa Electric’s next base load unit, the Polk Unit 2 – 5 conversion to combined cycle.

In June 2013, President Barack Obama announced his “Climate Action Plan” a broad package of mostly administrative initiatives aimed at reducing GHG emissions by approximately 17 percent below 2005 levels by 2020. EPA regulation of GHG emissions from new and existing power plants are the plan’s primary elements. These regulations were anticipated long before the president’s announcement, however the president provided additional details on both timing and substance. With respect to new power plants, pursuant to the directive, EPA released a re-proposed rule in September 2013 and is taking comments on the proposal until March 10, 2014. The president also directed EPA to issue a draft rule for existing power plants by June 1, 2014, to finalize the rule by June 1, 2015, and to require states to submit implementation plans by June 30, 2016. Because both rules will be subjected to litigation, legal challenges could also have material impact on both the timing and substance of EPA’s new climate rules.

Tampa Electric expects that the costs to comply with new environmental regulations would be eligible for recovery through the ECRC. If approved as prudent, the costs required to comply with CO_2 emissions reductions would be reflected in customers' bills. If the regulation allowing cost recovery is changed and the cost of compliance is not recovered through the ECRC, Tampa Electric could seek to recover those costs through a base-rate proceeding, but cannot predict whether the FPSC would grant such recovery. Tampa Electric's current solid-fuel energy generation was about 55% of its total system output in 2013, compared to being approximately 84% of its output in 2001. This is due to the conversion of the coal-fired Gannon Power Station into the natural gas-fired Bayside Power Station. However, solid fuel-fired facilities remain a significant component of Tampa Electric's diverse generation fleet and additional solid fuel units could be considered in the future.

In the case of TECO Coal, there are not yet federal limits on GHG emissions for this sector, and it is unclear if future requirements for GHG emissions reductions would directly impact it as a carbon-based fuel provider or the end users of its products. In either case, these requirements could make the use of coal more expensive or less desirable, which could impact TECO Coal's margins and profitability.

Water Supply and Quality

The EPA's final Clean Water Act Section 316(b) rule took effect in 2004. The rule established aquatic protection requirements for existing facilities that withdraw 50 million gallons or more of water per day from rivers, streams, lakes, reservoirs, estuaries, oceans, or other U.S. waters for cooling purposes. Tampa Electric uses water from Tampa Bay at its Bayside and Big Bend facilities as cooling water. Both plants use mesh screens to reduce the adverse impacts to aquatic organisms, and Big Bend units 3 and 4 use proprietary fine-mesh screens, BACT, to further reduce impacts to aquatic organisms. Subsequent to promulgation of the rule, a number of states, environmental groups and others sought judicial review of the rule. In 2007, the U.S. Court of Appeals for the Second Circuit overturned and remanded several provisions of the rule to the EPA for revisions. Among other things, the court rejected the EPA's use of "cost-benefit" analysis and suggested some ways to incorporate cost considerations. The Supreme Court agreed to review the Second Circuit's decision and heard arguments in December 2008. The EPA decided to rewrite the rule, and proposed a new rule in the summer of 2013. After several delays, the final rule is scheduled for April 2014. The full impact of the new regulations will depend on subsequent legal proceedings, the results of studies and analyses performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies.

On Dec. 6, 2010, the EPA published its final rule, setting numeric nutrient criteria for Florida's lakes and flowing waters. The rule, as published, is being challenged in the courts by numerous parties, including the state of Florida. The rule sets numeric limits for nitrogen and phosphorous in lakes and streams and for nitrate plus nitrite in springs. The EPA promulgated the rule pursuant to the terms of a consent decree approved by the court in Florida Wildlife Federation v. Jackson, 08-0324 (N.D. Fla.), in which environmentalists sued the EPA for allegedly violating a duty under the Federal Water Pollution Control Act (Clean Water Act or Act) to set the numeric criteria. In response to comments raising numerous implementation concerns, the EPA decided to delay the effective date of the criteria until 15 months after publication. The EPA announced that, in the interim, it would undertake a series of implementation steps in Florida, including an "education and outreach rollout," training meetings, and the development of guidance materials to coincide with the expected comment period on proposed site-specific alternative criteria. On Nov. 30, 2012, the EPA approved the FDEP rule in its entirety. The EPA proposed additional criteria in December 2012, including a re-proposal of streams criteria that were previously invalidated by the court. In January 2014, the EPA consent decree was revised allowing only the FDEP criteria to be implemented in Florida. Streams criteria may still directly affect Polk Power Station's cooling reservoir discharge to surface water, which may require the station to reduce the amount of nutrients in the cooling reservoir water before discharge.

After the completion of a study into wastewater discharges by the electric utility industry in 2009, the EPA announced its intent to revise the existing steam electric effluent limit guidelines (ELGs) that place technology-based limits on wastewater discharges. The rulemaking will focus on wastewater discharges from scrubbers, fly ash and bottom ash sluicing processes, leachate from ponds and landfills containing CCRs, IGCC processes, and flue gas mercury controls. The EPA is evaluating a suite of technology options which include treatment processes for wastewater discharges as well as the conversion to dry handling of fly ash and bottom ash to allow for zero discharge of transport water. Final impacts will vary depending on the mandated technology, the volume of wastewater to be treated and the pollutant limits. Tightened limits are anticipated for mercury, selenium, trace metals, and chlorides. New guidelines will likely add stricter limits to future NPDES permits in 2014-2019 (based on the five-year permit cycle).

Section 404 of the Clean Water Act and Coal Surface Mine Permits

Since 2008, the issuance of permits by the USACE under Section 404 of the Clean Water Act required for surface mining activities in the Central and Northern Appalachian mining regions has been challenged in the courts by various environmental groups.

On April 1, 2010, the EPA issued new guidance on environmental permitting requirements for Appalachian mountaintop removal and other surface mining projects. The guidance limits conductivity (level of mineral salts) in water discharges into streams from permitted areas, and was effective immediately on an interim basis. In July 2011, the EPA made this guidance final without modification. Because the EPA's standards appear to be unachievable under most circumstances, surface mining activity could be substantially curtailed since most new and pending permits would likely be rejected. This guidance could also be extended to discharges from deep mines and preparation plants, which could result in a substantial curtailing of those activities as well.

This guidance was challenged in the courts by a number of coal mining industry-related organizations, states and municipalities relating to the stringency of the standards as well as the focus on the coal industry and the Appalachian region in particular. In July 2012, the U. S. District Court for the District of Columbia ruled that the EPA had exceeded its statutory authority in establishing the water quality guidance discussed above in the manner in which it was done. Following the outcome of this court decision, pending appeals by the EPA, few, if any, new permits have been issued by USACE.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and PGS divisions, is a 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, 2013, TEC has estimated its ultimate financial liability to be $40.4 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other" on the Consolidated Condensed Balance Sheets. 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 portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC'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.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's actual percentage of the remediation costs.

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. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Coal Combustion Residuals Recycling and Disposal

The combustion of coal at two of Tampa Electric's power-generating facilities, the Big Bend and Polk Power stations, produces ash and other by-products, collectively known as CCRs. The CCRs produced at Big Bend include fly ash, FGD gypsum, boiler slag, bottom ash and economizer ash. The CCRs produced at the Polk Power Station include gasifier slag and sulfuric acid. Overall, over 97% of all CCRs produced at these facilities were marketed to customers for beneficial use in commercial and industrial products. The remaining 3% were either disposed of onsite or shipped offsite to nearby industrial waste landfills in Central Florida.

In response to a coal ash pond failure at another utility in December 2008, the EPA proposed new regulations for the management and disposal of CCRs. These proposed rules include two potential designations of CCRs. One designation would categorize CCRs destined for disposal as hazardous wastes. This is the most significant for TEC, because hazardous waste landfills are currently prohibited in Florida by state law, so CCRs destined for disposal would have to be shipped out of state as hazardous waste at significantly increased costs. In addition, the hazardous designation could require improvements to Tampa Electric's current ash management practices and interim storage and handling facilities for CCRs inside its power stations, even though permanent onsite disposal would not be allowed. The other proposed rule would set minimum standards for the final disposal of CCRs under regulations similar to those in place for municipal non-hazardous solid waste. This proposal would not be as disruptive as the former, since it would allow for the continued operation of Tampa Electric's existing, lined ash ponds. However, this latter proposal would place additional management requirements on these existing disposal units, which would eventually reach the end of their useful life and need to be replaced. The EPA's current schedule would result in a final proposed rule in 2014, although expected litigation would likely delay the rule's effective date.

Renewable Energy

Renewables are a component of Tampa Electric's environmental portfolio. Tampa Electric's renewable energy program offers to sell renewable energy as an option to customers and utilizes energy generated in the state from renewable sources (e.g. biomass and solar). To date, more than 62 million kWh of renewable energy have been produced by Tampa Electric and other renewable energy generating sources within Florida to support participating customer requirements.

Tampa Electric has installed over 100 kW of solar panels to generate electricity from the sun at six community sites including two schools, Tampa Electric's Manatee Viewing Center, the Museum of Science and Industry, Tampa's Lowry Park Zoo and the Florida Aquarium. Tampa Electric's largest solar panel array, rated at 43.8 kW, is located at Tampa Electric's Manatee Viewing Center in Apollo Beach, Florida. The electricity the photovoltaic array generates, which flows to Tampa Electric's grid, could offset the carbon dioxide emissions produced by seven typical-size cars in a year. The company continues to evaluate opportunities for additional solar panel installations.

Conservation

Energy conservation is becoming increasingly important in a period of volatile energy prices and in the GHG emissions reduction debate. In December 2009, the FPSC established new aggressive demand-side-management (DSM) goals for 2010-2019 for all investor-owned electric utilities. For Tampa Electric, the summer and winter demand goals are 138 and 109 MWs, respectively, and the annual energy goal is 360 gigawatt-hours. Even though these goals are set as a 10-year program, a review of the goals is required every five years. Tampa Electric's programs are scheduled to be reviewed by the FPSC in 2014.

During 2013, Tampa Electric continued to offer its customers a comprehensive array of residential and commercial programs that enabled the company to meet its required DSM goals, reduce weather-sensitive peak demand and conserve energy. This strategy continues to allow Tampa Electric to delay construction of future generation facilities. Since their inception, the company's conservation programs have reduced the summer peak demand by 319 MW and the winter peak demand by 719 MW. These programs and their costs are approved annually by the FPSC with the costs recovered through a clause on the customer's bill. In addition, PGS offers programs that enable customers to reduce their energy consumption with the costs also recovered through a clause on the customer's bill.

REGULATION

Tampa Electric's and PGS's retail operations 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 provides an opportunity for the utility to collect total revenues (revenue requirements) equal to its cost to provide service, plus a reasonable return on invested capital.

For both Tampa Electric and PGS, the costs of owning, operating and maintaining the utility systems, excluding fuel and conservation costs as well as purchased power and certain environmental costs for the electric system, are recovered through base rates. These costs include O&M expense, depreciation and taxes, as well as a return on investment in assets used and useful in providing electric and natural gas distribution services (rate base). The rate of return on rate base, which is intended to approximate the individual company's weighted cost of capital, primarily includes its costs for debt, deferred income taxes at a zero-cost rate and an allowed ROE. Base rates are determined in FPSC revenue requirement and rate setting hearings which occur at irregular intervals at the initiative of Tampa Electric, PGS, the FPSC or other parties.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary 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 the **Environmental Compliance** section).

Tampa Electric - Base Rates

In 2011, 2012 and 2013 prior to Nov. 1, the rates and allowed ROE in effect for Tampa Electric had been established in 2009 and in a series of subsequent decisions in 2009 and 2010. The allowed ROE during this period was a range of 10.25% to 12.25%, with a midpoint of 11.25%.

As a result of growth in rate base from required infrastructure added to serve customers, increasing pressure on O&M expense, and an economic recovery that was slower than expected compared to the assumptions in Tampa Electric's last base rate proceeding in 2009, on April 5, 2013, Tampa Electric filed its petition with the FPSC for an increase in base rates and miscellaneous service charges in the amount of $134.8 million. In the petition, Tampa Electric requested an ROE level of 11.25% and a capital structure identical to that approved in 2009, with 54% equity.

After extensive testimony by Tampa Electric and discovery by five intervening parties and the FPSC Staff, on Sept. 6, 2013, Tampa Electric and all of the intervening parties reached a Stipulation and Settlement Agreement resolving all of the issues in the proceeding.

On Sept. 11, 2013, the FPSC approved the Settlement that authorized base rate increases implemented at four different dates.

1. Nov. 1, 2013: $57.5 million increase
2. Nov. 1, 2014: Additional $7.5 million increase ($65 million versus current rates)
3. Nov. 1, 2015: Additional $5 million increase ($70 million versus current rates)
4. Jan. 1, 2017: Implementation of a Generation Base Rate Adjustment representing a $110 million additional increase on Jan. 1, 2017, or on the in-service date of the Polk 2-5 conversion, whichever is later.

The Settlement authorized an ROE of 10.25% and equity ratio of 54%, with a provision that ROE becomes 10.50% if at any time during the agreement the six month average 30-year US Treasury Bond yield increases 75 basis points. Base rates will not change if the ROE trigger were to take effect; however, for purposes of cost recovery clauses, AFUDC and surveillance reporting, there would be an adjustment to reflect the 10.50%.

As part of the settlement, Tampa Electric discontinued its annual $8 million storm damage expense accrual at Nov. 1, 2013 and the company will utilize a 15-year amortization period for all software retroactive to Jan. 1, 2013. The company will not be able to file for new base rates to be effective sooner than Jan. 1, 2018, subject to a bilateral opportunity for Tampa Electric or Interveners to initiate a rate proceeding if actual reported ROE falls below a floor of 9.25% or above a ceiling of 11.25%, subject to the 25 basis point incremental ROE if triggered. Lastly, the company is required to file a depreciation study no fewer than 60 days but no more than one year before filing its next base rate request.

The Settlement also contained various changes with respect to rate design. The company will implement a new Commercial and Industrial Service Rider (CISR) and an Economic Development Rate. The new Economic Development Rate will be implemented on a pilot basis for a three-year period and limited by the maximum amount of economic development expenditures as specified in Commission rules, which is approximately $3 million. The current lock-in period for interruptible credits will extend from three to six years and the Standby Generator credit will be adjusted from $4.00 to $4.75.

FERC Audit

On Nov. 6, 2012, Tampa Electric received notification from the FERC that its accounting practices and financial reporting processes would be audited, along with compliance with the FERC's records retention requirements. This was considered a routine audit by the FERC staff, though it had been approximately 20 years since Tampa Electric last had a FERC accounting audit.

No material issues have been identified as a result of the audit, and Tampa Electric expects to have an exit audit conference with the FERC staff in 2014, and thereafter to receive a letter from the FERC describing the results of the completed audit.

Tampa Electric Cost-Recovery Clauses

In November 2013, the FPSC approved Tampa Electric's rates for the various cost-recovery clauses for the period January 2014 through December 2014. Tampa Electric's fuel filing reflected continued historically low natural gas prices as well as good unit performance more than offset by a lower projected recovery of 2013 fuel costs, which resulted in Tampa Electric seeking a $2.40 increase in its fuel charges for 2014 for a residential customer using 1,000 kWh per month. As of Jan. 1, 2014, the total bill for a residential customer using 1,000 kWh is $109.61, compared to the November 2013 bill of $108.26, which includes the base rate increase discussed above, an increase of $1.35.

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.

Unlike the retail electric business, Tampa Electric competes in the wholesale power market with other energy providers in Florida, including other IOUs, municipal and other utilities, as well as co-generators or other unregulated power generators with uncontracted excess capacity. Entities compete to provide energy on a short-term basis (i.e., hourly or daily) and on a longer term basis. Competition in these markets is primarily based on having available energy to sell to the wholesale market and the price. In Florida, available energy for the wholesale market is affected by the state's PPSA, which sets the state's electric energy and environmental policy and governs the building of new generation involving steam capacity of 75 MW or more, that requires that applicants demonstrate that a plant is needed prior to receiving construction and operating permits. The effect of the PPSA has been to limit the number of unregulated generating units with excess capacity for sale in the wholesale power markets in Florida.

FPSC rules promote cost-competitiveness in the building of new steam generating capacity by requiring IOUs, such as Tampa Electric, 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 MW. The rules, which allow independent power producers and others to bid to supply the new generating capacity, 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.

Tampa Electric is not a major participant in the wholesale market because it uses lower cost coal-fired generation to serve its retail customers rather than the wholesale market. Over the past three years, gross revenues from wholesale sales, which include fuel that is a pass-through cost, have averaged approximately 2% of Tampa Electric's total revenue.

In many areas of the country there is growing use of rooftop solar panels, small wind turbines and other small scale methods of power generation, called distributed generation, by individual residential, commercial and industrial customers, or by third-party developers. Distributed generation is encouraged and supported by various special interest groups, tax incentives, renewable portfolio standards and special rates designed to support such generation. Tampa Electric offers rebate programs of up to $1.5 million annually to encourage development of solar installations and third-party developers offer attractive financing and leasing arrangements to encourage project development. In Florida, third parties that are not subject to regulation by the FPSC are not permitted to make direct sales of electricity to end use customers. The allowance of direct third party sales would take action by the Florida legislature, which is not expected in its 2014 session.

PGS Rates

PGS's rates and allowed ROE range of 9.75% to 11.75%, with a midpoint of 10.75%, and an equity ratio of 54.7%, which was established in 2009, 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 PGS, FPSC or other interested parties.

As a result of the unprecedented cold winter weather in 2010, in the second quarter of 2010, PGS projected it would earn above the top of its ROE cap of 11.75% in 2010. PGS recorded a $9.2 million pretax total provision related to the 2010 earnings above the top of the range. In December 2010, PGS and the Office of Public Counsel entered into a stipulation and settlement agreement requesting FPSC approval that $3.0 million pretax of the provision to be refunded to customers in the form of a credit on customers' bills in 2011, and the remainder be applied to accumulated depreciation reserves. On Jan. 25, 2011 the FPSC approved the stipulation.

PGS Cost-Recovery Clauses

PGS recovers the costs it pays for gas supply and interstate transportation for system supply through the PGA clause. This clause 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 delivers to its customers. These charges may be adjusted monthly based on a cap approved annually during an

FPSC hearing. The cap is based on estimated costs of purchased gas and pipeline capacity, and estimated customer usage for a calendar year recovery period, with a true-up adjustment to reflect the variance of actual costs and usage to projected charges for prior periods. In November 2013, the FPSC approved PGS' request for its PGA cap factor of $0.9185 per therm effective January 2014 through December 2014. In addition to its base rates and PGA clause charges, PGS customers (except interruptible customers) also pay a per-therm conservation charge for all gas. This charge is intended to permit PGS to recover 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, prudently incurred expenditures made in connection with these programs if it demonstrates the programs are cost-effective for its ratepayers.

In 2012, the FPSC approved a Cast Iron/Bare Steel Pipe Replacement Rider to recover the cost of accelerating the replacement of cast iron and bare steel distribution lines in the PGS system. Utilities nationwide have been encouraged by the U.S. Department of Transportation to replace this older infrastructure as a safety measure. The FPSC approved PGS' request to accelerate the replacement program of approximately 5%, or 500 miles, of the PGS system at a cost of approximately $80 million over a 10-year period.

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, propane and fuel oil. PGS has taken actions to retain and expand its natural gas distribution business, including managing costs and providing high quality service to customers.

In Florida, gas service is unbundled for all non-residential customers. PGS has a "NaturalChoice" program, offering unbundled transportation service to all eligible customers and allowing non-residential customers and residential customers using more than 1,999 therms annually to purchase commodity gas from a third party but continue to pay PGS for the transportation. 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 20,500 transportation-only customers as of Dec. 31, 2013, out of approximately 35,000 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 by-passing PGS facilities, or by other utilities seeking to expand existing distribution systems to new customers previously unserved by another utility. In response to this competition, PGS has developed various programs, including the provision of transportation services at discounted rates.

ITEM 7A 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 also administers the policy with respect to interest rate risk exposures. Under the policy, 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 that 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, our companies enter into futures, forwards, swaps and option contracts to limit the exposure to items such as:

- 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; and
- Price fluctuations for physical purchases of fuel at TECO Coal.

Our 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

Accounting standards for derivative instruments and hedging activities require us 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 OCI or net 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 **Note 16** to the **TECO Energy Consolidated Financial Statements**).

Fair Value Measurements

The company has adopted the accounting standards for fair value measurement. These standards define fair value, establish a framework for measuring fair value under GAAP, and expand disclosures about financial assets and liabilities carried at fair value. The majority of the company's financial assets and liabilities are in the form of natural gas, heating oil or interest rate derivatives classified as cash flow hedges. This adoption did not have a material impact on our results of operations, liquidity or capital.

Most natural gas derivatives were entered into by the regulated utilities to manage the impact of natural gas prices on customers. As a result of applying the provisions of accounting standards for regulated activities, the changes in value of natural gas derivatives of Tampa Electric and PGS are recorded as regulatory assets or liabilities to reflect the impact of the risks of hedging activities in the fuel recovery clause. Because the amounts are deferred and ultimately collected through the fuel clause, the unrealized gains and losses associated with the valuation of these assets and liabilities do not impact our results of operations.

Heating oil and diesel fuel hedges are used to mitigate the fluctuations in the price of diesel fuel, which is a significant component in the cost of coal production at TECO Coal and its subsidiaries.

The valuation methods we used to determine fair value are described in **Note 17** 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 for credit purposes and managed as appropriate, considering the legal structure and any netting agreements in place. Credit exposures are calculated, compared to limits and reported to management on a daily basis. The Credit Guidelines are administered and monitored within the Middle Office, independent of the Front Office.

We have implemented procedures to monitor the creditworthiness of our counterparties and to consider nonperformance in valuing counterparty positions. Net liability positions are generally not adjusted as we use our derivative transactions as hedges and we have the ability and intent to perform under each of our contracts. In the instance of net asset positions, we consider general market conditions and the observable financial health and outlook of specific counterparties, forward-looking data such as credit default swaps when available and historical default probabilities from credit rating agencies in evaluating the potential impact of nonperformance risk to derivative positions.

Certain of our derivative instruments contain provisions that require our debt, or in the case of derivative instruments where TEC is the counterparty, TEC's debt, to maintain an investment-grade credit rating from any or all of the major credit rating agencies. If our debt ratings, including TEC's, were to fall below investment grade, it could trigger these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features were in asset positions on Dec. 31, 2013.

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, 2013 and 2012, 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 low amounts of variable rate debt at TECO Energy and at our subsidiaries. A hypothetical 10% decrease in interest rates would increase the fair market value of our long-term debt by approximately 2.8% at Dec. 31, 2013, and 2.7% at Dec. 31, 2012 (see the **Financing Activity** section and **Notes 6 and 7** to the **TECO Energy Consolidated Financial Statements**). These amounts were determined based on the variable rate obligations existing on the indicated dates at TECO Energy and its subsidiaries. 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. 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 were 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's commodity price risks are largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through FPSC-approved 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 impact of fuel price changes on customers, both Tampa Electric and PGS 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, 2013 and 2012, a change in commodity prices would not have had a material impact on earnings for Tampa Electric or PGS, but could have had an impact on the timing of the cash recovery of the cost of fuel (see the Tampa Electric and Regulation sections).

TECO Coal

TECO Coal is subject to significant commodity risk. TECO Coal does not speculate using derivative instruments. However, all derivative instruments may not 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. 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, 2013, TECO Coal had derivative instruments in place to reduce the price variability for its anticipated 2014 diesel oil purchases for nearly all coal production volumes sold under contracts that did not include a fuel price component. Accordingly, a change in the average annual price for diesel oil is not expected to significantly change TECO Coal's cost of production.

Changes in Fair Value of Derivatives (millions)

Net fair value of derivatives as of Dec. 31, 2012	$ (15.0)
Additions and net changes in unrealized fair value of derivatives	7.0
Changes in valuation techniques and assumptions	0.0
Realized net settlement of derivatives	17.7
Net fair value of derivatives as of Dec. 31, 2013	$ 9.7

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

Total derivative net liabilities as of Dec. 31, 2012	$ (15.0)
Change in fair value of net derivative assets:	
Recorded as regulatory assets and liabilities or other comprehensive income	7.0
Recorded in earnings	0.0
Realized at settlement of derivatives	17.7
Net option premium payments	0.0
Net purchase (sale) of existing contracts	0.0
Net fair value of derivatives as of Dec. 31, 2013	$ 9.7

Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2013

(millions)	**Current**	**Non-current**	**Total Fair Value**
Source of fair value			
Actively quoted prices	$ 0.0	$ 0.0	$ 0.0
Other external price sources [(1)]	9.6	0.1	9.7
Model prices [(2)]	0.0	0.0	0.0
Total	$ 9.6	$ 0.1	$ 9.7

(1) Reflects over-the-counter natural gas or diesel fuel swaps for which the primary pricing inputs in determining fair value are NYMEX quoted closing prices of exchange-traded instruments.
(2) Model prices are used for determining the fair value of energy derivatives where price quotes are infrequent or the market is illiquid. Significant inputs to the models are derived from market-observable data and actual historical experience.

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

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Report of Independent Registered Certified Public Accounting Firm

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of TECO Energy, Inc and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in the 1992 *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company’s internal control over financial reporting is a process designed 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.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida

February 28, 2014

TECO ENERGY, INC.
Consolidated Balance Sheets

Assets *(millions)*	*Dec. 31, 2013*	*Dec. 31, 2012*
Current assets		
Cash and cash equivalents	$ 185.2	$ 200.5
Receivables, less allowance for uncollectibles of $4.7 and $4.2 at Dec. 31, 2013 and 2012, respectively	287.2	282.7
Inventories, at average cost		
Fuel	118.7	123.6
Materials and supplies	85.9	82.1
Derivative assets	9.7	0.0
Regulatory assets	34.3	70.3
Deferred income taxes	100.3	63.3
Prepayments and other current assets	34.9	33.9
Income tax receivables	1.5	0.4
Total current assets	857.7	856.8
Property, plant and equipment		
Utility plant in service		
Electric	6,934.0	6,655.8
Gas	1,308.3	1,228.3
Construction work in progress	386.7	336.1
Other property	448.3	443.8
Property, plant and equipment, at original costs	9,077.3	8,664.0
Accumulated depreciation	(2,907.2)	(2,695.5)
Total property, plant and equipment, net	6,170.1	5,968.5
Other assets		
Regulatory assets	293.1	382.6
Derivative assets	0.3	0.2
Deferred charges and other assets	126.8	126.8
Total other assets	420.2	509.6
Total assets	$ 7,448.0	$ 7,334.9

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

TECO ENERGY, INC.
Consolidated Balance Sheets – continued

Liabilities and Capital *(millions)*	*Dec. 31, 2013*	*Dec. 31, 2012*
Current liabilities		
Long-term debt due within one year	$ 83.3	$ 0.0
Notes payable	84.0	0.0
Accounts payable	261.7	232.8
Customer deposits	164.5	162.9
Regulatory liabilities	85.8	105.6
Derivative liabilities	0.1	14.6
Interest accrued	31.9	33.2
Taxes accrued	34.6	32.1
Other	19.5	19.9
Total current liabilities	765.4	601.1
Other liabilities		
Deferred income taxes	444.0	277.9
Investment tax credits	9.4	9.7
Regulatory liabilities	631.4	631.4
Derivative liabilities	0.2	0.6
Deferred credits and other liabilities	426.1	549.7
Long-term debt, less amount due within one year	2,837.8	2,972.7
Total other liabilities	4,348.9	4,442.0
Commitments and Contingencies (see **Note 12**)		
Capital		
Common equity (400.0 million shares authorized; par value $1; 217.3 million and 216.6 million shares outstanding at Dec. 31, 2013 and 2012, respectively)	217.3	216.6
Additional paid in capital	1,581.3	1,564.5
Retained earnings	548.3	541.7
Accumulated other comprehensive loss	(13.2)	(31.0)
Total TECO Energy capital	2,333.7	2,291.8
Total liabilities and capital	$ 7,448.0	$ 7,334.9

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

TECO ENERGY, INC.
Consolidated Statements of Income

(millions, except per share amounts) *For the years ended Dec. 31,*		*2013*	*2012*	*2011*
Revenues				
Regulated electric and gas (includes franchise fees and gross receipts taxes of $108.5 in 2013, $111.5 in 2012 and $109.3 in 2011)		$ 2,342.5	$ 2,377.4	$ 2,469.8
Unregulated		508.8	619.2	740.1
Total revenues		2,851.3	2,996.6	3,209.9
Expenses				
Regulated operations and maintenance				
Fuel		680.2	694.7	731.4
Purchased power		64.7	105.3	125.9
Cost of natural gas sold		142.2	155.7	210.4
Other		524.4	462.5	436.9
Operation and maintenance other expense				
Mining related costs		419.0	461.1	574.1
Other		12.5	7.9	7.1
Depreciation and amortization		329.5	330.6	317.2
Taxes, other than income		215.1	222.3	223.7
Total expenses		2,387.6	2,440.1	2,626.7
Income from operations		463.7	556.5	583.2
Other income (expense)				
Allowance for other funds used during construction		6.3	2.6	1.0
Other income		3.6	9.4	6.7
Loss on debt extinguishment		0.0	(1.2)	0.0
Total other income		9.9	10.8	7.7
Interest charges				
Interest expense		170.5	185.0	198.0
Allowance for borrowed funds used during construction		(3.6)	(1.5)	(0.6)
Total interest charges		166.9	183.5	197.4
Income from continuing operations before provision for income taxes		306.7	383.8	393.5
Provision for income taxes		108.9	137.8	142.7
Net income from continuing operations		197.8	246.0	250.8
Discontinued operations				
Income (loss) from discontinued operations		(0.2)	(10.6)	33.3
Provision for income taxes		(0.1)	22.4	11.2
Income (loss) from discontinued operations, net		(0.1)	(33.0)	22.1
Less: Income from discontinued operations attributable to noncontrolling interest		0.0	0.3	0.3
Income (loss) from discontinued operations attributable to TECO Energy, net		(0.1)	(33.3)	21.8
Net income attributable to TECO Energy		$ 197.7	$ 212.7	$ 272.6
Average common shares outstanding	– Basic	215.0	214.3	213.6
	– Diluted	215.5	215.0	215.1
Earnings per share from continuing operations	– Basic	$0.92	$1.14	$1.17
	– Diluted	$0.92	$1.14	$1.17
Earnings per share from discontinued operations attributable to TECO Energy	– Basic	$0.00	($0.15)	$0.10
	– Diluted	$0.00	($0.15)	$0.10
Earnings per share attributable to TECO Energy	– Basic	$0.92	$0.99	$1.27
	– Diluted	$0.92	$0.99	$1.27
Dividends paid per common share outstanding		$0.88	$0.88	$0.85

Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 19**.

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

TECO ENERGY, INC.
Consolidated Statements of Comprehensive Income

(millions) *For the years ended Dec. 31,*	*2013*	*2012*	*2011*
Net income attributable to TECO Energy	$ 197.7	$ 212.7	$ 272.6
Other comprehensive income (loss), net of tax			
Net unrealized gains (losses) on cash flow hedges	1.4	(4.2)	(0.8)
Amortization of unrecognized benefit costs and other	14.8	(4.8)	(4.6)
Recognized benefit costs due to settlement	1.6	0.0	0.6
Other comprehensive income (loss), net of tax	17.8	(9.0)	(4.8)
Comprehensive income attributable to TECO Energy	$ 215.5	$ 203.7	$ 267.8

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

TECO ENERGY, INC.
Consolidated Statements of Cash Flows

(millions) *For the years ended Dec. 31,*	*2013*	*2012*	*2011*
Cash flows from operating activities			
Net income attributable to TECO Energy	$ 197.7	$ 212.7	$ 272.6
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	329.5	337.7	324.6
Deferred income taxes	110.4	136.9	146.0
Investment tax credits	(0.3)	(0.3)	(0.4)
Allowance for other funds used during construction	(6.3)	(2.6)	(1.0)
Non-cash stock compensation	13.5	12.0	9.1
(Gain) loss on sales of business/assets, pretax	(1.6)	18.5	(0.5)
Deferred recovery clauses	(6.2)	(8.9)	(9.0)
Asset impairment, pretax	0.0	17.2	0.0
Receivables, less allowance for uncollectibles	(4.5)	37.7	5.7
Inventories	1.1	(2.4)	23.5
Prepayments and other current assets	(2.2)	(2.0)	(2.8)
Taxes accrued	1.4	12.1	(5.7)
Interest accrued	(1.3)	(5.9)	0.3
Accounts payable	35.9	(1.3)	(42.6)
Other	(8.5)	(4.7)	34.3
Cash flows from operating activities	658.6	756.7	754.1
Cash flows from investing activities			
Capital expenditures	(532.4)	(505.1)	(454.1)
Allowance for other funds used during construction	6.3	2.6	1.0
Net proceeds from sales of business/assets	4.3	194.4	3.5
Restricted cash	0.0	8.9	0.0
Other investing activities	0.0	0.0	14.4
Cash flows used in investing activities	(521.8)	(299.2)	(435.2)
Cash flows from financing activities			
Dividends	(191.2)	(190.4)	(183.2)
Proceeds from the sale of common stock	6.7	3.9	7.0
Proceeds from long-term debt issuance	0.0	538.1	0.0
Repayment of long-term debt/Purchase in lieu of redemption	(51.6)	(650.4)	(153.6)
Change in short-term debt	84.0	0.0	(12.0)
Other financing activities	0.0	(2.2)	(0.6)
Cash flows used in financing activities	(152.1)	(301.0)	(342.4)
Net (decrease) increase in cash and cash equivalents	(15.3)	156.5	(23.5)
Cash and cash equivalents at beginning of the year	200.5	44.0	67.5
Cash and cash equivalents at end of the year	$ 185.2	$ 200.5	$ 44.0
Supplemental disclosure of cash flow information			
Cash paid during the year for:			
Interest	$ 161.0	$ 188.4	$ 191.6
Income taxes paid	$ 1.8	$ 7.2	$ 9.4

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

TECO ENERGY, INC.
Consolidated Statements of Capital

(millions)	Shares [1]	Common Stock	Additional Paid in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Capital
Balance, Dec. 31, 2010	214.9	$214.9	$1,542.0	$430.0	($17.2)	$0.9	$2,170.6
Net income				272.6		0.3	272.9
Other comprehensive loss, after tax					(4.8)		(4.8)
Common stock issued	0.9	0.9	0.1				1.0
Cash dividends declared				(183.2)			(183.2)
Stock compensation expense			9.1				9.1
Noncontrolling - dividends						(0.6)	(0.6)
Tax benefits - stock compensation			2.2				2.2
Balance, Dec. 31, 2011	215.8	$215.8	$1,553.4	$519.4	($22.0)	$0.6	$2,267.2
Net income				212.7		0.3	213.0
Other comprehensive loss, after tax					(9.0)		(9.0)
Common stock issued	0.8	0.8	(3.7)				(2.9)
Cash dividends declared				(190.4)			(190.4)
Stock compensation expense			12.0				12.0
Noncontrolling - dividends						(0.3)	(0.3)
Tax benefits - stock compensation			2.8				2.8
Noncontrolling - sale of business						(0.6)	(0.6)
Balance, Dec. 31, 2012	216.6	$216.6	$1,564.5	$541.7	($31.0)	$0.0	$2,291.8
Net income				197.7			197.7
Other comprehensive income, after tax					17.8		17.8
Common stock issued	0.7	0.7	5.2				5.9
Cash dividends declared				(191.2)			(191.2)
Stock compensation expense			13.5				13.5
Restricted stock - dividends			1.0	0.1			1.1
Tax short fall - stock compensation			(2.9)				(2.9)
Balance, Dec. 31, 2013	217.3	$217.3	$1,581.3	$548.3	($13.2)	$0.0	$2,333.7

(1) TECO Energy had a maximum of 400.0 million shares of $1 par value common stock authorized as of Dec. 31, 2013, 2012, 2011 and 2010.

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

TECO ENERGY, INC.
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 and Basis of Presentation

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

For entities that are determined to meet the definition of a 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 (see **Note 18**).

Use of Estimates

The use of estimates is inherent in the preparation of financial statements in accordance with GAAP. Actual results could differ from these estimates.

Restricted Cash

Restricted cash of $8.7 million related to cash held in escrow for the 2003 sale of HPP, was released from escrow in 2012 upon maturity of debt financing that was held by the purchaser of HPP. There was no restricted cash at Dec. 31, 2013.

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.

Planned Major Maintenance

Planned major maintenance projects that do not increase the overall life or value of the related assets are expensed as incurred. 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 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 FPSC and FERC regulations.

Depreciation

Tampa Electric and PGS compute depreciation and amortization for electric generation, electric transmission and distribution, gas distribution and general plant facilities using the following methods:

- the group remaining life method, approved by the FPSC, is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property;
- the amortizable life method, approved by the FPSC, is applied to the net book value to date over the remaining life of those assets not classified as depreciable property above.

The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 3.7% for 2013 and 3.8% for 2012 and 3.6% for 2011.

On Sept. 11, 2013, the FPSC unanimously voted to approve a stipulation and settlement agreement between TEC and all of the intervenors in its Tampa Electric division base rate proceeding. As a result, Tampa Electric will begin using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013.

Other TECO Energy subsidiaries compute depreciation primarily by the straight-line method at annual rates that amortize the original cost, less net salvage value, of depreciable property over the following estimated useful lives:

Asset	Estimated Useful Lives
Building and improvements	5 - 40 years
Office equipment and furniture	3 - 30 years
Vehicles, mining and other equipment	2 - 15 years
Coal processing facilities	7 - 20 years
Computer software	2 - 15 years

Total depreciation expense for the years ended Dec. 31, 2013, 2012 and 2011 was $316.5 million, $309.3 million and $306.6 million, respectively.

Allowance for Funds Used During Construction

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 FPSC approved rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 8.16% for May 2009 through December 2013. Total AFUDC for the years ended Dec. 31, 2013, 2012 and 2011 was $9.9 million, $4.1 million and $1.6 million, respectively.

Inventory

TEC values materials, supplies and fossil fuel inventory (coal, oil and natural gas) using a weighted-average cost method. These materials, supplies and fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered with a normal profit upon sale in the ordinary course of business. TECO Coal inventories are stated at the lower of cost, computed on the first-in, first-out method, or net realizable value. Parts and supplies inventories are stated at the lower of cost or market on an average cost basis.

Fuel Inventory *(millions)*	*Dec. 31, 2013*	*Dec. 31, 2012*
TEC	$93.7	$89.1
TECO Coal	25.0	34.5
Total	$118.7	$123.6

Regulatory Assets and Liabilities

Tampa Electric and PGS are subject to accounting guidance for the effects of certain types of regulation (see **Note 3** for additional details).

Deferred Income Taxes

TECO Energy uses the asset and liability method to determine deferred income taxes. Under the asset and 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 assets will not be realized. If management determines that it is likely that some or all of deferred tax assets will not be realized, then a valuation allowance is recorded to report the balance at the amount expected to be realized (see **Note 4** for additional details).

Investment Tax Credits

ITCs 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 accounting standards for revenue recognition. 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.

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 the FERC. See **Note 3** for a discussion of significant regulatory matters and the applicability of the accounting guidance for certain types of regulation to the company.

Revenues for TECO Coal shipments, both domestic and international, are recognized when title and risk of loss transfer to the customer.

Revenues for energy marketing operations at TECO Energy Source are presented on a net basis in accordance with the accounting guidance for reporting revenue gross as a principal versus net as an agent and recognition and reporting of gains and losses on energy trading contracts 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, 2013, 2012 and 2011 were $23.1 million, $13.8 million and $2.5 million, respectively.

Shipping and Handling

TECO Coal includes the costs to ship product to customers in "Operation & maintenance other expense - Mining related costs" on the Consolidated Statements of Income which for the years ended Dec. 31, 2013, 2012 and 2011 were $8.2 million, $9.0 million and $16.6 million, respectively.

Cash Flows Related to Derivatives and Hedging Activities

The company classifies cash inflows and outflows related to derivative and hedging instruments in the appropriate cash flow sections associated with the item being hedged. In the case of diesel fuel swaps, which are used to mitigate the fluctuations in the price of diesel fuel, the cash inflows and outflows are included in the operating section. For natural gas and ongoing interest rate swaps, the cash inflows and outflows are included in the operating section. For interest rate swaps that settle coincident with the debt issuance, the cash inflows and outflows are treated as premiums or discounts and included in the financing section of the Consolidated Statements of Cash Flows.

Revenues and Cost Recovery

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- 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 regulatory liabilities, and under-recoveries of costs are recorded as regulatory assets.

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, 2013 and 2012, unbilled revenues of $46.7 million and $49.0 million, respectively, are included in the "Receivables" line item on TECO Energy's Consolidated Balance Sheets.

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. Tampa Electric purchased power from non-TECO Energy affiliates at a cost of $64.7 million, $105.3 million and $125.9 million, for the years ended Dec. 31, 2013, 2012 and 2011, 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 incurs 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 on a dollar-per-dollar basis 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. 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". These amounts totaled $108.5 million, $111.5 million and $109.3 million for the years ended Dec. 31, 2013, 2012 and 2011, respectively.

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.

Debt issuance costs – The company capitalizes the external costs of obtaining debt financing and includes them in "Deferred charges and other assets" on TECO Energy's Consolidated Balance Sheet and amortizes such costs over the life of the related debt on a straight-line basis that approximates the effective interest method. These amounts are reflected in "Interest expense" on TECO Energy's Consolidated Statements of Income.

Deferred Credits and Other Liabilities

Other deferred credits primarily include the accrued postretirement and pension liabilities, and medical and general liability claims incurred but not reported. 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 and workers' compensation using discount rates mandated by statute or otherwise deemed appropriate for the circumstances. Discount rates used in estimating these other self-insurance liabilities at Dec. 31, 2013 and 2012 ranged from 3.51% to 4.86% and 2.60% to 4.00%, respectively.

Stock-Based Compensation

TECO Energy accounts for its stock-based compensation in accordance with the accounting guidance for share-based payment. Under the provisions of this guidance, 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). See **Note 9** for more information on share-based payments.

Receivables and Allowance for Uncollectible Accounts

Receivables consist of services billed to residential, commercial, industrial and other customers. An allowance for uncollectible accounts is established based on Tampa Electric's and PGS's collection experience. Circumstances that could affect Tampa Electric's and PGS's estimates of uncollectible receivables include, but are not limited to, customer credit issues, the level of natural gas prices, customer deposits and general economic conditions. Accounts are written off once they are deemed to be uncollectible. TECO Coal's receivables consist of coal sales billed to industrial and utility customers. An allowance for uncollectible accounts is established based on TECO Coal's collection experience. Circumstances that could affect TECO Coal's estimates of uncollectable receivables include customer credit issues and general economic conditions. Accounts are written off once they are determined to be uncollectible.

Reclassifications

Certain reclassifications were made to prior year amounts to conform to current period presentation. None of the reclassifications affected TECO Energy's net income in any period.

2. New Accounting Pronouncements

Unrecognized Tax Benefits

In July 2013, the FASB issued guidance regarding the presentation of unrecognized tax benefits in the statement of position when a net operating loss carryforward, a similar tax loss or a tax credit carryforward exists. It requires that an unrecognized tax benefit be presented as a reduction to a deferred tax asset for net operating loss carryforwards, similar tax losses or tax credit carryforwards, with certain exceptions. The guidance is effective for interim and annual reporting periods beginning on or after Dec. 15, 2013. The guidance will have no effect on the company's results of operations, financial position or cash flows.

Comprehensive Income

In February 2013, the FASB issued guidance requiring improved disclosures of significant reclassifications out of AOCI and their corresponding effect on net income. The guidance is effective for interim and annual reporting periods beginning on or after Dec. 15, 2012. The company has adopted this guidance as required. It has no effect on the company's results of operations, financial position or cash flows.

Offsetting Assets and Liabilities

In December 2011, the FASB issued guidance enhancing disclosures of financial instruments and derivative instruments that are offset in the statement of financial position or subject to enforceable master netting agreements. The guidance is effective for interim and annual reporting periods beginning on or after Jan. 1, 2013. The company has adopted this guidance as required. It had no effect on the company's results of operations, financial position or cash flows.

3. Regulatory

Tampa Electric's and PGS's retail businesses are regulated by the FPSC. Tampa Electric is also subject to regulation by the FERC under PUHCA 2005. However, pursuant to a waiver granted in accordance with the FERC's regulations, TECO Energy is not subject to certain accounting, record-keeping and reporting requirements prescribed by the FERC's regulations under PUHCA 2005. The operations of PGS are regulated by the FPSC separately from the operations of Tampa Electric. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC sets rates at a level that allows utilities such as Tampa Electric and PGS to collect total revenues (revenue requirements) equal to their cost of providing service, plus a reasonable return on invested capital.

Base Rates-Tampa Electric

Tampa Electric's results for the first ten months of 2013, and all of 2012 and 2011, reflect base rates established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE midpoint of 11.25%, 54.0% equity in the capital structure and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for CTs and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

On Feb. 4, 2013, Tampa Electric delivered a letter to the FPSC notifying it of its intent to file a request for an increase in its retail base rates and service charges. On April 5, 2013, Tampa Electric filed a petition with the FPSC requesting, among other things, a permanent increase in rates and service charges sufficient to generate additional annual revenues of approximately $134.8 million, to be effective on or after Jan. 1, 2014. The request provided for a return on equity range of 10.25% to 12.25% with a midpoint of 11.25%. The petition also requested certain changes to existing rate schedules, as well as the adoption of new rate designs.

On Sept. 6, 2013, TEC and all of the intervenors in its Tampa Electric division base rate proceeding filed with the FPSC a joint motion for the FPSC to approve a stipulation and settlement agreement, which would resolve all matters in Tampa Electric's pending base rate proceeding.

This agreement provided for the following revenue increases: $57.5 million effective Nov. 1, 2013, an additional $7.5 million effective Nov. 1, 2014, an additional $5.0 million effective Nov. 1, 2015, and an additional $110.0 million effective Jan. 1, 2017 or the date that the expansion of TEC's Polk Power Station goes into service, whichever is later. The agreement provides that Tampa Electric's allowed regulatory ROE would be a mid-point of 10.25% with a range of plus or minus 1%, with a potential increase to 10.50% if U.S. Treasury bond yields exceed a specified threshold. The agreement provides that Tampa Electric cannot file for additional rate increases until 2017 (to be effective in 2018), unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE is increased as described above) any party to the agreement other than TEC could seek a review of Tampa Electric's base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital and Tampa Electric will begin using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013.

On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement between TEC and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved Tampa Electric's base rate proceeding.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services and accounting practices.

Storm Damage Cost Recovery

Prior to the above mentioned stipulation and settlement agreement, Tampa Electric was accruing $8.0 million annually to a FERC-authorized and FPSC-approved self-insured storm damage reserve. This reserve was created after Florida's IOUs were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Tampa Electric's storm reserve was $56.1 million and $50.4 million as of Dec. 31, 2013 and 2012, respectively. Effective Nov. 1, 2013, Tampa Electric ceased accruing for this storm damage reserve. However, in the event of a named storm that results in damage to its system, Tampa Electric can petition the FPSC to seek recovery of those costs over a 12-month period or longer as determined by the FPSC, as well as replenish its reserve to the level as of Oct. 31, 2013.

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.

Tampa Electric and PGS apply the accounting standards for regulated operations. 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 the deferral of costs as regulatory assets to the period in which the regulatory agency recognizes them, when cost recovery is ordered over a period longer than a fiscal year.

Details of the regulatory assets and liabilities as of Dec. 31, 2013 and 2012 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Dec. 31, 2013*	*Dec. 31, 2012*
Regulatory assets:		
Regulatory tax asset [1]	$ 67.4	$ 67.2
Other:		
Cost-recovery clauses	6.1	42.9
Postretirement benefit asset	182.7	276.1
Deferred bond refinancing costs [2]	8.0	9.2
Environmental remediation	51.4	46.9
Competitive rate adjustment	4.1	4.1
Other	7.7	6.5
Total other regulatory assets	260.0	385.7
Total regulatory assets	327.4	452.9
Less: Current portion	34.3	70.3
Long-term regulatory assets	$ 293.1	$ 382.6
Regulatory liabilities:		
Regulatory tax liability [1]	$ 9.8	$ 14.6
Other:		
Cost-recovery clauses	54.5	73.9
Transmission and delivery storm reserve	56.1	50.4
Deferred gain on property sales [3]	2.0	3.4
Provision for stipulation and other	0.8	1.0
Accumulated reserve - cost of removal	594.0	593.7
Total other regulatory liabilities	707.4	722.4
Total regulatory liabilities	717.2	737.0
Less: Current portion	85.8	105.6
Long-term regulatory liabilities	$ 631.4	$ 631.4

(1) Primarily related to plant life and derivative positions.

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

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

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

Regulatory assets

(millions)	*Dec. 31, 2013*	*Dec. 31, 2012*
Clause recoverable [1]	$ 10.2	$ 47.0
Components of rate base [2]	185.6	279.1
Regulatory tax assets [3]	67.4	67.2
Capital structure and other [3]	64.2	59.6
Total	$ 327.4	$ 452.9

(1) To be recovered through recovery mechanisms 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 a 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 Taxes

In 2013, 2012 and 2011, TECO Energy recorded net tax provisions of $108.8 million, $160.2 million and $153.9 million, respectively. A majority of this provision is non-cash. TECO Energy has net operating losses that are being utilized to reduce its taxable income. As such, cash taxes paid for income taxes as required for the alternative minimum tax, state income taxes, foreign income taxes and prior year audits in 2013, 2012 and 2011 were $1.8 million, $7.2 million and $9.4 million, respectively.

Income tax expense consists of the following:

Income Tax Expense (Benefit)			
(millions)			
For the year ended Dec. 31,	*2013*	*2012*	*2011*
Continuing Operations			
Current income taxes			
Federal	$2.2	$15.7	$0.0
State	(3.5)	1.1	0.9
Deferred income taxes			
Federal	98.6	102.9	124.0
State	11.9	18.4	18.2
Amortization of investment tax credits	(0.3)	(0.3)	(0.4)
Income tax expense from continuing operations	$108.9	$137.8	$142.7
Discontinued Operations			
Current income taxes			
Federal	$0.0	$0.0	$0.0
Foreign	0.0	6.8	7.4
State	0.0	0.0	0.0
Deferred income taxes			
Federal	(0.1)	14.9	4.4
Foreign	0.0	0.0	(0.3)
State	0.0	0.7	(0.3)
Income tax expense from discontinued operations	(0.1)	22.4	11.2
Total income tax expense	$108.8	$160.2	$153.9

During 2013, TECO Energy increased its net operating loss carryforward. Total current income tax expense for the years ended Dec. 31, 2012 and 2011 was reduced by $13.6 million and $32.1 million, respectively, to reflect the benefits of operating loss carryforwards.

The reconciliation of the federal statutory rate to the company's effective income tax rate is as follows:

Effective Income Tax Rate

(millions) *For the year ended Dec. 31,*	*2013*	*2012*	*2011*
Income tax expense at the federal statutory rate of 35%	$107.3	$134.3	$137.7
Increase (decrease) due to:			
State income tax, net of federal income tax	5.5	12.7	12.4
Equity portion of AFUDC	(2.2)	(0.9)	(0.4)
Valuation allowance	0.0	1.1	0.0
Depletion	(3.7)	(8.5)	(9.1)
Other	2.0	(0.9)	2.1
Total income tax expense from continuing operations	$108.9	$137.8	$142.7
Income tax expense as a percent of income from continuing operations, before income taxes	35.5%	35.9%	36.3%

For the three years presented, the overall effective tax rate on continuing operations was higher than the 35% U.S. federal statutory rate primarily due to state income taxes offset by depletion.

As discussed in **Note 1**, TECO Energy uses the asset and liability method to determine deferred income taxes. Based primarily on the reversal of deferred income tax liabilities and future earnings of the company's utility operations, management has determined that the net deferred tax assets recorded at Dec. 31, 2013 will be realized in future periods.

The major components of the company's deferred tax assets and liabilities recognized are as follows:

Deferred Income Taxes

(millions) *As of Dec. 31,*	*2013*	*2012*
Deferred tax liabilities [1]		
Property related	$ 1,164.2	$ 1,023.3
Deferred fuel	1.6	11.3
Pension	52.8	43.0
Total deferred tax liabilities	1,218.6	1,077.6
Deferred tax assets [1]		
Alternative minimum tax credit carryforward	213.0	211.8
Loss and credit carryforwards [2]	479.8	473.2
Other postretirement benefits	68.9	68.0
Other	113.2	113.0
Total deferred tax assets	874.9	866.0
Valuation allowance	0.0	(3.0)
Total deferred tax assets, net of valuation allowance	874.9	863.0
Total deferred tax liability, net	343.7	214.6
Less: Current portion of deferred tax asset	(100.3)	(63.3)
Long-term portion of deferred tax liability, net	$ 444.0	$ 277.9

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

(2) As a result of certain realization requirements of accounting guidance, loss carryforwards do not include certain deferred tax assets as of Dec. 31, 2013 that arose directly from tax deductions related to equity compensation greater than compensation recognized for financial reporting. Stockholder's equity will be increased by $1.1 million when such deferred tax assets are ultimately realized. The company uses tax law ordering when determining when excess tax benefits have been realized.

At Dec. 31, 2013, the company had cumulative unused federal and state (Florida) NOLs for income tax purposes of $1,321.9 million and $392.6 million, respectively, expiring at various times between 2025 and 2028. In addition, the company has unused general business credits of $3.9 million expiring between 2026 and 2032. Due to the sale of the company's remaining Guatemalan operations, unused foreign tax credits of $38.5 million have been reclassed to net operating loss. During 2013, the company's available alternative minimum tax credit carryforward for tax purposes increased from $211.8 million to $213.0 million, reflecting the future AMT payable for the amendment of prior years' federal income tax returns to claim a deduction for foreign tax paid. The alternative minimum tax credit may be used indefinitely to reduce federal income taxes.

The company's consolidated balance sheet reflects loss carryforwards excluding amounts resulting from excess stock-based compensation. Accordingly, such losses from excess stock-based compensation tax deductions are accounted for as an increase to additional paid-in capital if and when realized through a reduction in income taxes payable.

The company establishes valuation allowances on its deferred tax assets, including losses and tax credits, when the amount of expected future taxable income is not likely to support the use of the deduction or credit. A state capital loss carryforward valuation allowance of $3.0 million was recorded as of Dec. 31, 2012. For the year ended Dec. 31, 2013, the company recorded a full valuation allowance release of $3.0 million due to the expiration of the state capital loss carryforward.

The company accounts for uncertain tax positions in accordance with FASB guidance. This guidance addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under the guidance, the company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The guidance also provides standards on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

Unrecognized Tax Benefits

(millions)	*2013*	*2012*
Balance at Jan. 1,	$2.9	$4.1
Decreases due to tax positions related to prior years	0.0	0.0
Decreases due to settlements with taxing authorities	0.0	0.0
Decreases due to expiration of statute of limitations	(2.9)	0.0
Dispositions	0.0	(1.2)
Balance at Dec. 31,	$0.0	$2.9

The company recognizes interest and penalties associated with uncertain tax positions in “Operation other expense – Other” in the Consolidated Statements of Income. In 2013, 2012 and 2011, the company recognized $(0.9) million, $0.3 million and $0.2 million, respectively, of pretax charges (benefits) for interest only. Additionally, the company had $0.0 million of interest accrued at Dec. 31, 2013 and $0.9 million of interest accrued at Dec. 31, 2012. No amounts have been recorded for penalties. As a result of the 2012 sale of TCAE, interest and penalties recorded on TCAE’s books for an uncertain tax position have been removed from the company’s unrecognized tax benefits (see **Note 19).**

The company’s U.S. subsidiaries join in the filing of a U.S. federal consolidated income tax return. The IRS concluded its examination of the company’s 2012 consolidated federal income tax return in January 2014. The U.S. federal statute of limitations remains open for the year 2010 and forward. The federal income tax return for calendar year 2013 is part of the IRS’s Compliance Assurance Program. As a result, the IRS audit of such return is expected to be completed in 2014. U.S. state jurisdictions have statutes of limitations generally ranging from three to four years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by taxing authorities in major state jurisdictions include 2010 and forward. The company does not expect the settlement of audit examinations to significantly change the total amount of unrecognized tax benefits within the next 12 months.

5. Employee Postretirement Benefits

Pension Benefits

TECO Energy has a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on employees’ age, years of service and final average earnings.

The Pension Protection Act became effective Jan. 1, 2008 and requires companies to, among other things, maintain certain defined minimum funding thresholds (or face plan benefit restrictions), pay higher premiums to the PBGC if they sponsor defined benefit plans, amend plan documents and provide additional plan disclosures in regulatory filings and to plan participants.

WRERA was signed into law on Dec. 23, 2008. WRERA grants plan sponsors relief from certain funding requirements and benefits restrictions, and also provides some technical corrections to the Pension Protection Act. There are two primary provisions that impact funding results for TECO Energy. First, for plans funded less than 100%, required shortfall contributions will be based on a percentage of the funding target until 2012, rather than the funding target of 100%. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging subject to certain limitations in the determination of funding requirements. TECO Energy utilizes asset smoothing in determining funding requirements.

In July 2012, the President signed into law the MAP-21. MAP-21 provides funding relief for pension plan sponsors by stabilizing discount rates used in calculating the required minimum pension contributions and increasing PBGC premium rates to be paid by plan sponsors. The company expects the required minimum pension contributions to be lower than the levels previously projected; however, the company plans on funding at levels above the required minimum pension contributions under MAP-21.

The qualified pension plan’s actuarial value of assets, including credit balance, was 96.7% of the Pension Protection Act funded target as of Jan. 1, 2013 and is estimated at 98.2% of the Pension Protection Act funded target as of Jan. 1, 2014.

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

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. 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.

MMA 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.

The FASB issued accounting guidance and disclosure requirements related to the MMA. The guidance 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.

In March 2010, the Patient Protection and Affordable Care Act and a companion bill, the Health Care and Education Reconciliation Act, collectively referred to as the Health Care Reform Acts, were signed into law. Among other things, both acts reduce the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, TECO Energy reduced its deferred tax asset in 2010 and recorded a true up in 2012. TEC is amortizing the regulatory asset over the remaining average service life of 12 years. Additionally, the Health Care Reform Acts contain other provisions that may impact TECO Energy's obligation for retiree medical benefits. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase its PBO. TECO Energy will continue to monitor and assess the impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

Effective Jan. 1, 2013, the company decided to implement an EGWP for its post-65 retiree prescription drug plan. The EGWP is a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduces net periodic benefit cost by taking advantage of rebate and discount enhancements provided under the Health Care Reform Acts. Prior to this, the company received subsidy payments under Medicare Part D for its post-65 retiree prescription drug plan.

Obligations and Funded Status

TECO Energy recognizes in its statement of financial position the over-funded or under-funded status of its postretirement benefit plans. This status is measured as the difference between the fair value of plan assets and the PBO in the case of its defined benefit plan, or the APBO in the case of its other postretirement benefit plan. Changes in the funded status are reflected, net of estimated tax benefits, in the benefit liabilities and AOCI in the case of the unregulated companies, or the benefit liabilities and regulatory assets in the case of TEC. The results of operations are not impacted. Below is the detail of the change in benefit obligations, change in plan assets, unfunded liability and amounts recognized in the Consolidated Balance Sheets for 2013 and 2012.

Obligations and Funded Status	**Pension Benefits**		**Other Benefits**	
(millions)	*2013*	*2012*	*2013*	*2012*
Change in benefit obligation				
Net benefit obligation at beginning of year	$715.0	$646.4	$230.3	$216.5
Service cost	18.2	17.0	2.5	2.4
Interest cost	28.9	30.1	9.3	10.1
Plan participants' contributions	0.0	0.0	2.9	3.7
Plan amendments	0.0	0.0	0.0	(5.2)
Actuarial loss (gain)	(50.4)	54.7	(22.1)	16.3
Gross benefits paid	(43.1)	(33.2)	(15.0)	(14.5)
Settlements	(2.6)	0.0	0.0	0.0
Federal subsidy on benefits paid	n/a	n/a	0.2	1.0
Net benefit obligation at end of year	$666.0	$715.0	$208.1	$230.3
Change in plan assets				
Fair value of plan assets at beginning of year	$529.1	$467.6	$0.0	$0.0
Actual return on plan assets	63.7	57.9	0.0	0.0
Employer contributions	45.9	36.8	11.9	9.8
Plan participants' contributions	0.0	0.0	2.9	3.7
Settlements	(2.6)	0.0	0.0	0.0
Net benefits paid	(43.1)	(33.2)	(14.8)	(13.5)
Fair value of plan assets at end of year	$593.0	$529.1	$0.0	$0.0
Funded status				
Fair value of plan assets (1)	$593.0	$529.1	$0.0	$0.0
Less: Benefit obligation (PBO/APBO)	666.0	715.0	208.1	230.3
Funded status at end of year	(73.0)	(185.9)	(208.1)	(230.3)
Unrecognized net actuarial loss	173.1	270.3	19.7	42.7
Unrecognized prior service (benefit) cost	(0.4)	(0.7)	(0.7)	(1.0)
Net amount required to be recognized at end of year	$99.7	$83.7	($189.1)	($188.6)
Amounts recognized in balance sheet				
Regulatory assets	$139.6	$216.5	$43.2	$59.6
Accrued benefit costs and other current liabilities	(3.3)	(5.3)	(13.3)	(13.1)
Deferred credits and other liabilities	(69.7)	(180.6)	(194.8)	(217.2)
Accumulated other comprehensive loss (income), pretax	33.1	53.1	(24.2)	(17.9)
Net amount recognized at end of year	$99.7	$83.7	($189.1)	($188.6)

(1) The MRV of plan assets is used as the basis for calculating the EROA component of periodic pension expense. MRV reflects the fair value of plan assets adjusted for experience gains and losses (i.e. the differences between actual investment returns and expected returns) spread over five years.

Amounts recognized in accumulated other comprehensive income

	Pension Benefits		**Other Benefits**	
(millions)	*2013*	*2012*	*2013*	*2012*
Net actuarial loss (gain)	$ 32.7	$ 52.7	$ (23.8)	$ (17.2)
Prior service cost (credit)	0.4	0.4	(0.4)	(0.7)
Amount recognized	$ 33.1	$ 53.1	$ (24.2)	$ (17.9)

The accumulated benefit obligation for all defined benefit pension plans was $624.1 million at Dec. 31, 2013 and $664.7 million at Dec. 31, 2012. The projected benefit obligation for the other postretirement benefits plan was $208.1 million at Dec. 31, 2013 and $230.3 million at Dec. 31, 2012.

Assumptions used to determine benefit obligations at Dec. 31:

	Pension Benefits		Other Benefits	
	2013	*2012*	*2013*	*2012*
Discount rate	5.118%	4.196%	5.096%	4.180%
Rate of compensation increase - weighted	3.73%	3.76%	3.71%	3.74%
Healthcare cost trend rate				
Immediate rate	n/a	n/a	7.25%	7.50%
Ultimate rate	n/a	n/a	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	2025	2025

A one-percentage-point change in assumed health care cost trend rates would have the following effect on the benefit obligation:

(millions)	1% Increase	1% Decrease
Effect on postretirement benefit obligation	$ 6.8	$ (6.1)

The discount rate assumption used to determine the Dec. 31, 2013 benefit obligation was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

Net periodic benefit cost	Pension Benefits			Other Benefits		
(millions)	*2013*	*2012*	*2011*	*2013*	*2012*	*2011*
Service cost	$ 18.2	$ 17.0	$ 16.0	$ 2.4	$ 2.4	$ 2.1
Interest cost	28.9	30.1	30.9	9.3	10.1	11.1
Expected return on plan assets	(38.4)	(37.1)	(38.4)	0.0	0.0	0.0
Amortization of:						
Actuarial loss	20.5	15.3	11.3	1.0	0.1	0.1
Prior service (benefit) cost	(0.4)	(0.4)	(0.4)	(0.3)	0.8	0.8
Transition obligation	0.0	0.0	0.0	0.0	1.8	2.3
Settlement loss	1.0	0.0	0.9	0.0	0.0	0.0
Net periodic benefit cost	$ 29.8	$ 24.9	$ 20.3	$ 12.4	$ 15.2	$ 16.4

Other Changes in Plan Assets and Benefit Obligations Recognized in OCI and regulatory assets						
(millions)	*2013*	*2012*	*2011*	*2013*	*2012*	*2011*
Prior service cost	$0.0	$0.0	$0.0	$0.0	$ (5.2)	$0.0
Net loss (gain)	(75.7)	34.0	43.3	(15.6)	16.3	(7.4)
Amortization of:						
Actuarial gain (loss)	(21.5)	(15.3)	$ (12.2)	(1.0)	(0.1)	(0.1)
Prior service (benefit) cost	0.4	0.4	0.4	0.3	(0.8)	(0.8)
Transition obligation	0.0	0.0	0.0	0.0	(1.8)	(2.4)
Total recognized in OCI and regulatory assets	$ (96.8)	$ 19.1	$ 31.5	$ (16.3)	$ 8.4	$ (10.7)
Total recognized in net periodic benefit cost, OCI and regulatory assets	$ (67.0)	$ 44.0	$ 51.8	$ (3.9)	$ 23.6	$ 5.7

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year are $2.5 million and $0.1 million, respectively. The estimated prior service credit for the other postretirement benefit plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year is $0.2 million.

In addition, the estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year are $10.5 million and $0.5 million, respectively. There will be no remaining net loss for the other postretirement benefit plan that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31:

	Pension Benefits			Other Benefits		
	2013	*2012*	*2011*	*2013*	*2012*	*2011*
Discount rate	4.196%	4.797%	5.300%	4.180%	4.744%	5.250%
Expected long-term return on plan assets	7.50%	7.50%	7.75%	n/a	n/a	n/a
Rate of compensation increase	3.76%	3.83%	3.88%	3.74%	3.82%	3.87%
Healthcare cost trend rate						
Initial rate	n/a	n/a	n/a	7.50%	7.75%	8.00%
Ultimate rate	n/a	n/a	n/a	4.50%	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	n/a	2025	2025	2023

The discount rate assumption used to determine the 2013 benefit cost was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan’s year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

The expected return on assets assumption was based on historical returns, fixed income spreads and equity premiums consistent with the portfolio and asset allocation at the measurement date. A change in asset allocations could have a significant impact on the expected return on assets. Additionally, expectations of long-term inflation, real growth in the economy and a provision for active management and expenses paid were incorporated in the assumption. For the year ended Dec. 31, 2013, TECO Energy’s pension plan experienced actual asset returns of approximately 12%.

The compensation 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.

A one-percentage-point change in assumed health care cost trend rates would have the following effect on expense:

(millions)	**1% Increase**	**1% Decrease**
Effect on periodic cost	$ 0.3	$ (0.3)

Pension Plan Assets

Pension plan assets (plan assets) are primarily 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 and funding requirements over the long term. 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.

	Target Allocation	Actual Allocation, End of Year	
Asset Category		*2013*	*2012*
Equity securities	48%-54%	54%	55%
Fixed income securities	46%-52%	46%	45%
Total	100%	100%	100%

The company reviews the plan’s asset allocation periodically and re-balances the investment mix to maximize asset returns, optimize the matching of investment yields with the plan’s expected benefit obligations, and minimize pension cost and funding. The company expects to take additional steps to more closely match plan assets with plan liabilities.

The plan’s investments are held by a trust fund administered by JP Morgan Chase Bank, N.A. (JP Morgan). JP Morgan measures fair value using the procedures set forth below for all investments. When available, JP Morgan uses quoted market prices on investments traded on an exchange to determine fair value and classifies such items as Level 1. In some cases where a market exchange price is available, but the investments are traded in a secondary market, JP Morgan makes use of acceptable practical expedients to calculate fair value, and the company classifies these items as Level 2.

If observable transactions and other market data are not available, fair value is based upon third-party developed models that use, when available, current market-based or independently-sourced market parameters such as interest rates, currency rates or option volatilities. Items valued using third-party generated models are classified according to the lowest level input or value driver that is most significant to the valuation. Thus, an item may be classified in Level 3 even though there may be significant inputs that are readily observable.

As required by the fair value accounting standards, the investments are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The plan's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For cash equivalents, the cost approach was used in determining fair value. For bonds and U.S. government agencies, the income approach was used. For other investments, the market approach was used. The following table sets forth by level within the fair value hierarchy the plan's investments as of Dec. 31, 2013 and Dec. 31, 2012.

Pension Plan Investments

(millions)	**At Fair Value as of Dec. 31, 2013**			
	Level 1	**Level 2**	**Level 3**	**Total**
Accounts receivable	$44.7	$0.0	$0.0	$44.7
Accounts payable	(40.8)	0.0	0.0	(40.8)
Cash equivalents				
Short term investment funds (STIFs)	7.9	0.0	0.0	7.9
Treasury bills (T bills)	0.0	0.3	0.0	0.3
Repurchase agreement	0.0	8.8	0.0	8.8
Commercial paper	0.0	0.4	0.0	0.4
Money markets	0.0	1.5	0.0	1.5
Total cash equivalents	7.9	11.0	0.0	18.9
Equity securities				
Common stocks	91.6	0.0	0.0	91.6
American depository receipts (ADRs)	3.0	0.0	0.0	3.0
Real estate investment trusts (REITs)	1.7	0.0	0.0	1.7
Preferred stock	0.0	0.8	0.0	0.8
Mutual funds	172.6	0.0	0.0	172.6
Commingled fund	0.0	50.0	0.0	50.0
Total equity securities	268.9	50.8	0.0	319.7
Fixed income securities				
Municipal bonds	0.0	7.3	0.0	7.3
Government bonds	0.0	35.7	0.0	35.7
Corporate bonds	0.0	19.6	0.0	19.6
Asset backed securities (ABS)	0.0	0.4	0.0	0.4
Mortgage-backed securities (MBS), net short sales	0.0	6.7	0.0	6.7
Collateralized mortgage obligations (CMOs)	0.0	2.3	0.0	2.3
Mutual fund	0.0	85.1	0.0	85.1
Commingled fund	0.0	94.1	0.0	94.1
Total fixed income securities	0.0	251.2	0.0	251.2
Derivatives				
Short futures	0.0	0.2	0.0	0.2
Swaps	0.0	(0.9)	0.0	(0.9)
Purchased options (swaptions)	0.0	0.2	0.0	0.2
Written options (swaptions)	0.0	(0.4)	0.0	(0.4)
Total derivatives	0.0	(0.9)	0.0	(0.9)
Miscellaneous	0.0	0.2	0.0	0.2
Total	$280.7	$312.3	$0.0	$593.0

Pension Plan Investments

(millions)	At Fair Value as of Dec. 31, 2012			
	Level 1	Level 2	Level 3	Total
Accounts receivable	$64.8	$0.0	$0.0	$64.8
Accounts payable	(72.8)	0.0	0.0	(72.8)
Cash equivalents				
STIFs	9.0	0.0	0.0	9.0
T bills	0.0	0.6	0.0	0.6
Repurchase agreements	0.0	23.1	0.0	23.1
CDs	0.0	1.1	0.0	1.1
Commercial paper	0.0	0.9	0.0	0.9
Money markets	0.0	0.6	0.0	0.6
Total cash equivalents	9.0	26.3	0.0	35.3
Equity securities				
Common stocks	125.3	0.0	0.0	125.3
ADRs	6.2	0.0	0.0	6.2
REITs	2.0	0.0	0.0	2.0
Preferred stocks	0.0	0.8	0.0	0.8
Equity mutual funds	153.4	0.0	0.0	153.4
Total equity securities	286.9	0.8	0.0	287.7
Fixed income securities				
Municipal bonds	0.0	8.0	0.0	8.0
Government bonds	0.0	53.0	0.0	53.0
Corporate bonds	0.0	19.8	0.0	19.8
ABS	0.0	0.5	0.0	0.5
MBS	0.0	17.6	0.0	17.6
CMBS	0.0	0.3	0.0	0.3
CMOs	0.0	2.5	0.0	2.5
Fixed income mutual fund	0.0	63.7	0.0	63.7
Fixed income commingled fund	0.0	49.4	0.0	49.4
Total fixed income securities	0.0	214.8	0.0	214.8
Derivatives				
Swaps	0.0	(0.5)	0.0	(0.5)
Purchased options (swaptions)	0.0	0.1	0.0	0.1
Written options (swaptions)	0.0	(0.4)	0.0	(0.4)
Total derivatives	0.0	(0.8)	0.0	(0.8)
Miscellaneous	0.0	0.1	0.0	0.1
Total	$287.9	$241.2	$0.0	$529.1

- The primary pricing inputs in determining the fair value of the Level 1 assets, excluding the mutual funds and STIF, are closing quoted prices in active markets.
- The STIF is valued at net asset value (NAV) as determined by JP Morgan. Shares may be redeemed any business day at the NAV calculated after the order is accepted. The NAV is validated with purchases and sales at NAV, making this a Level 1 asset.
- The primary pricing inputs in determining the Level 1 mutual funds are the mutual funds' NAVs. The funds are registered open-ended mutual funds and the NAVs are validated with purchases and sales at NAV, making these Level 1 assets.
- The repurchase agreements and money markets are valued at cost due to their short term nature. Additionally, repurchase agreements are backed by collateral.
- T bills and commercial paper are valued using benchmark yields, reported trades, broker dealer quotes, and benchmark securities.
- The primary pricing inputs in determining the fair value of the preferred stock is the price of underlying and common stock of the same issuer, average life, and benchmark yields.
- The methodology and inputs used to value the investment in the equity commingled fund are broker dealer quotes. The fund holds primarily international equity securities that are actively traded in OTC markets. The fund honors subscription and redemption activity on an "as of" basis.
- The primary pricing inputs in determining the fair value Level 2 municipal bonds are benchmark yields, historical spreads, sector curves, rating updates, and prepayment schedules. The primary pricing inputs in determining the fair value of government bonds are the U.S. Treasury curve, CPI, and broker quotes, if available. The primary pricing inputs in determining the fair value of corporate bonds are the U.S. treasury curve, base spreads, YTM, and benchmark quotes. ABS and CMOs are priced using TBA

prices, treasury curves, swap curves, cash flow information, and bids and offers as inputs. MBS are priced using TBA prices, treasury curves, average lives, spreads, and cash flow information. Commercial MBS are priced using payment information and yields.

- The primary pricing input in determining the fair value of the Level 2 mutual fund is its NAV. However, since this mutual fund is an unregistered open-ended mutual fund, it is a Level 2 asset.
- The fixed income commingled fund is a private fund valued at NAV as determined by a third party at year end. The fund invests in long duration U.S. investment-grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The NAV is calculated based on bid prices of the underlying securities. The fund honors subscription activity on the first business day of the month and the first business day following the 15th calendar day of the month. Redemptions are honored on the 15th or last business day of the month, providing written notice is given at least ten business days prior to withdrawal date.
- Futures are valued using futures data, cash rate data, swap rates, and cash flow analyses.
- Swaps are valued using benchmark yields, swap curves, and cash flow analyses.
- Options are valued using the bid-ask spread and the last price.

Other Postretirement Benefit Plan Assets

There are no assets associated with the company's other postretirement benefits plan.

Contributions

The company's policy is to fund the qualified pension plan at or above amounts determined by its actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. The company made $42.0 million and $35.5 million of contributions to this plan in 2013 and 2012, respectively, which met the minimum funding requirements for both 2013 and 2012. These amounts are reflected in the "Other" line on the Consolidated Statements of Cash Flows. The company estimates its contribution in 2014 to be $47.5 million and expects to make contributions from 2015 to 2018 in the range of $4.0 to $48.0 million per year based on current assumptions. These contributions are in excess of the minimum required contribution under ERISA guidelines.

The SERP is funded annually to meet the benefit obligations. The company made contributions of $2.6 million and $1.3 million to this plan in 2013 and 2012, respectively. In 2014, the company expects to make a contribution of about $3.3 million to this plan.

The other postretirement benefits are funded annually to meet benefit obligations. The company's 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's 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 2014, the company expects to make a contribution of about $13.3 million. Postretirement benefit levels are substantially unrelated to salary.

Benefit Payments

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

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

(millions)	Pension Benefits	Other Postretirement Benefits
2014	$ 53.5	$ 13.3
2015	50.9	13.9
2016	55.3	14.6
2017	55.9	15.2
2018	58.3	15.7
2019-2023	298.6	81.9

Defined Contribution Plan

The company has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries 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. Effective April 2013, employer matching contributions were 65% of eligible participant contributions with additional incentive match of up to 35% of eligible participant contributions based on the achievement of certain operating company financial goals. Prior to this, the employer matching contributions were 60% of eligible participant contributions, with an additional incentive match of up to 40%. For the years ended

Dec. 31, 2013, 2012 and 2011, the company and its subsidiaries recognized expense totaling $11.3 million, $7.0 million and $9.0 million, respectively, related to the matching contributions made to this plan.

Black Lung Liability

TECO Coal is required by federal and state statutes to provide benefits to terminated, retired or (under state statutes) qualifying active employees for benefits related to black lung disease. TECO Coal is self-insured for black lung related claims. Annual expense is recorded for black lung obligations as determined by an independent actuary at the present value of the actuarially computed liability for such benefits over the employee's applicable term of service. At Dec. 31, 2013 and 2012, TECO Coal had an actuarially-determined black lung liability of $24.5 million and $27.1 million, respectively. TECO Coal recognized expense related to the black lung liability of $2.2 million, $1.8 million, and $1.7 million for 2013, 2012 and 2011, respectively.

6. Short-Term Debt

At Dec. 31, 2013 and Dec. 31, 2012, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2013			*Dec. 31, 2012*		
(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 [2]	$325.0	$6.0	$0.7	$325.0	$0.0	$1.5
1-year accounts receivable facility	150.0	78.0	0.0	150.0	0.0	0.0
TECO Energy/TECO Finance:						
5-year facility [2][3]	200.0	0.0	0.0	200.0	0.0	0.0
Total	$675.0	$84.0	$0.7	$675.0	$0.0	$1.5

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

At Dec. 31, 2013, these credit facilities require commitment fees ranging from 12.5 to 25.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at Dec. 31, 2013 was 0.56%. There were no outstanding borrowings at Dec. 31, 2012.

Tampa Electric Company Accounts Receivable Facility

On Feb. 14, 2014, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 12 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A., Inc. as Program Agent. The amendment extends the maturity date to Feb. 13, 2015 and makes certain other technical changes. Please refer to **Note 24** for additional information.

Amendments of TECO Energy/TECO Finance Credit Facility

On Dec. 17, 2013, TECO Energy amended and restated its $200 million bank credit facility, entering into a Fourth Amended and Restated Credit Agreement (the TECO Credit Facility). The amendment (i) extends the maturity date of the credit facility from Oct. 25, 2016 to Dec. 17, 2018 (subject to further extension with the consent of each lender); (ii) continues with TECO Energy as Guarantor and its wholly-owned subsidiary, TECO Finance, as Borrower; (iii) allows TECO Finance to borrow funds at an interest rate equal to the London interbank deposit rate plus a margin; (iv) as an alternative to the above interest rate, allows TECO Finance to borrow funds at an interest rate equal to a margin plus the higher of the JPMorgan Chase Bank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (v) allows TECO Finance to borrow funds on a same-day basis under a swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (vi) allows TECO Finance to request the lenders to increase their commitments under the credit facility by $100 million in the aggregate; (vii) continues to include a $200 million letter of credit facility; and (ix) makes other technical changes.

The Fourth Amended and Restated Credit Agreement includes the changes made in Amendment No. 1 dated June 24, 2013 (Amendment) to the TECO Energy/TECO Finance Third Amended and Restated Credit Agreement dated Oct. 25, 2011. The Amendment was entered into to accommodate the acquisition of NMGI, as described in **Note 22** herein, by (i) temporarily changing the total debt to total capitalization financial covenant such that, during the four fiscal quarters commencing with the quarter in which the acquisition closes, TECO Energy must maintain a total debt to total capitalization ratio of no greater than 0.70 to 1.00, instead of the previous capitalization ratio of 0.65 to 1.00 and (ii) changing the definition of Permitted Liens as defined in the TECO Credit Facility to permit the acquisition of a significant subsidiary that carries secured debt and making other changes matching the corresponding covenant in the Bridge Facility, as described in **Note 22** herein.

Amendment of Tampa Electric Company Credit Facility

On Dec. 17, 2013, TEC amended and restated its $325 million bank credit facility, entering into a Fourth Amended and Restated Credit Agreement. The amendment (i) extends the maturity date of the credit facility from Oct. 25, 2016 to Dec. 17, 2018 (subject to further extension with the consent of each lender); (ii) continues to allow TEC to borrow funds at a rate equal to the London interbank deposit rate plus a margin; (iii) as an alternative to the above interest rate, allows TEC to borrow funds at an interest rate equal to a margin plus the higher of Citibank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (iv) allows TEC to borrow funds on a same-day basis under a swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the Borrower and the relevant swingline lender prior to the making of any such loans; (v) continues to allow TEC to request the lenders to increase their commitments under the credit facility by up to $175 million in the aggregate; (vi) includes a $200 million letter of credit facility; and (vii) made other technical changes.

7. Long-Term Debt

At Dec. 31, 2013, total long-term debt had a carrying amount of $2,921.1 million and an estimated fair market value of $3,184.1 million. At Dec. 31, 2012, total long-term debt had a carrying amount of $2,972.7 million and an estimated fair market value of $3,442.2 million. The company uses the market approach in determining fair value. The majority of the outstanding debt is valued using real-time financial market data obtained from Bloomberg Professional Service. The remaining securities are valued using prices obtained from the Municipal Securities Rulemaking Board and by applying estimated credit spreads obtained from a third party to the par value of the security. All debt securities are level 2 instruments.

TECO Finance is a 100% owned subsidiary of TECO Energy. TECO Finance’s sole purpose is to raise capital for TECO Energy’s diversified businesses. TECO Energy is a full and unconditional guarantor of TECO Finance’s securities, and no other subsidiaries of TECO Energy guarantee TECO Finance's securities.

A substantial part of Tampa Electric’s tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric’s first mortgage bond indenture.

TECO Energy’s gross maturities and annual sinking fund requirements of long-term debt for 2014 through 2018 and thereafter are as follows:

Long-Term Debt Maturities

As of Dec. 31, 2013 (millions)	*2014*	*2015*	*2016*	*2017*	*2018*	*Thereafter*	*Total Long-Term Debt*
TECO Finance	$0.0	$191.2	$250.0	$300.0	$0.0	$300.0	$1,041.2
Tampa Electric	83.3	83.3	83.4	0.0	254.2	1,146.7	1,650.9
PGS	0.0	0.0	0.0	0.0	50.0	181.7	231.7
Total long-term debt maturities	$83.3	$274.5	$333.4	$300.0	$304.2	$1,628.4	$2,923.8

Purchase in Lieu of Redemption of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 B

On Sept. 3, 2013, TEC purchased in lieu of redemption $51.6 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 B (the Series 2007 B HCIDA Bonds). On March 26, 2008, the HCIDA had remarketed the Series 2007 B HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2007 B HCIDA Bonds bore interest at a term rate of 5.15% per annum from March 26, 2008 to Sept. 1, 2013. TEC is responsible for payment of the interest and principal associated with the Series 2007 B HCIDA Bonds.

On March 15, 2012, TEC purchased in lieu of redemption $86.0 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (Non-AMT) (the Series 2006 HCIDA Bonds). On March 19, 2008, the HCIDA had remarketed the Series 2006 HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2006 HCIDA Bonds bore interest at a term rate of 5.00% per annum from March 19, 2008 to March 15, 2012. TEC is responsible for payment of the interest and principal associated with the Series 2006 HCIDA Bonds. Regularly scheduled principal and interest when due, are insured by Ambac Assurance Corporation.

On March 1, 2011, TEC purchased in lieu of redemption $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010 (the PCIDA Bonds). On Nov. 23, 2010, the PCIDA had issued the PCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the PCIDA Bonds were used to redeem $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric

Company Project), Series 2007, which previously had been in auction rate mode and had been held by TEC since March 26, 2008. The PCIDA Bonds bore interest at the initial term rate of 1.50% per annum from Nov. 23, 2010 to March 1, 2011.

On March 26, 2008, TEC purchased in lieu of redemption $20 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 C.

After the Sept. 3, 2013 purchase of the Series 2007 B HCIDA Bonds, $232.6 million in bonds purchased in lieu of redemption were held by the trustee at the direction of TEC as of Dec. 31, 2013 to provide an opportunity to evaluate refinancing alternatives.

Redemption of TECO Energy, Inc. 6.75% Notes due 2015

On Dec. 5, 2012, TECO Energy redeemed $8.8 million of 6.75% Notes due May 15, 2015. The redemption price was equal to $1,141.86 per $1,000.00 principal amount of notes redeemed, plus accrued and unpaid interest on the redeemed notes up to the redemption date. In connection with this transaction, $1.2 million of premiums were expensed, and are included in "Loss on debt extinguishment" on the Consolidated Statements of Income and as part of the "Cash flows from operating activities" in the Consolidated Statements of Cash Flows for the twelve months ended Dec. 31, 2012.

Redemption of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2002

On Oct. 1, 2012, TEC redeemed $147.1 million of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2002 due Oct. 1, 2013 and Oct. 1, 2023 (2002 Bonds) at a redemption price equal to 100% of the principal amount of the 2002 Bonds to be redeemed, plus accrued and unpaid interest to Oct. 1, 2012. Before the optional redemption, $60.7 million of the 2002 Bonds due Oct. 1, 2013 bore interest at 5.1% and $86.4 million of the 2002 Bonds due Oct. 1, 2023 bore interest at 5.5%.

Issuance of Tampa Electric Company 2.60% Notes due 2022

On Sept. 28, 2012, TEC completed an offering of $250 million aggregate principal amount of 2.60% Notes due 2022 (the 2022 Notes). The 2022 Notes were sold at 99.878% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $247.7 million. Net proceeds were used to repay the 2002 Bonds. The remaining net proceeds were used to repay short-term debt and for general corporate purposes. At any time prior to June 15, 2022, TEC may redeem all or any part of the 2022 Notes at its option at a redemption price equal to the greater of (i) 100% of the principal amount of 2022 Notes to be redeemed or (ii) the sum of the present values of the remaining payments of principal and interest on the 2022 Notes to be redeemed, discounted to the redemption date on a semiannual basis at an applicable treasury rate, plus 15 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after June 15, 2022, TEC may at its option redeem the 2022 Notes, in whole or in part, at 100% of the principal amount of the 2022 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

Issuance of Tampa Electric Company 4.10% Notes due 2042

On June 5, 2012, TEC completed an offering of $300 million aggregate principal amount of 4.10% Notes due 2042 (the 2042 Notes). The 2042 Notes were sold at 99.724% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, and estimated offering expenses and before settlement of interest rate swaps) of approximately $296.2 million. Net proceeds were used to repay maturing long-term debt, to repay short-term debt and for general corporate purposes. At any time prior to Dec. 15, 2041, TEC may redeem all or any part of the 2042 Notes at its option and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of the 2042 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the 2042 Notes to be redeemed, discounted at an applicable treasury rate, plus 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Dec. 15, 2041, TEC may at its option redeem the 2042 Notes, in whole or in part, at 100% of the principal amount of the 2042 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

Redemption of TECO Guatemala San José Project Notes

On Dec. 19, 2012, in conjunction with the closing on the sale of its equity interests in the San José Power Station, TECO Energy utilized $25.3 million of the sale proceeds to repay the San José project notes.

At Dec. 31, 2013 and 2012, TECO Energy had the following long-term debt outstanding:

Long-Term Debt *(millions) Dec. 31,*		*Due*	*2013*	*2012*
TECO Finance	Notes [1][2][3]: 6.75% (effective rate of 6.9%)	2015	$191.2	$191.2
	4.0% (effective rate of 4.2%)	2016	250.0	250.0
	6.572% (effective rate of 7.3%)	2017	300.0	300.0
	5.15% (effective rate of 5.3%)	2020	300.0	300.0
Total long-term debt of TECO Finance			1,041.2	1,041.2
Tampa Electric	Installment contracts payable [4]:			
	5.65% Refunding bonds (effective rate of 5.9%)	2018	54.2	54.2
	Variable rate bonds repurchased in 2008 [5]	2020	0.0	0.0
	5.15% Refunding bonds repurchased in 2013 (effective rate of 5.4% for 2012) [6]	2025	0.0	51.6
	1.5% Term rate bonds repurchased in 2011[7]	2030	0.0	0.0
	5.0% Refunding bonds repurchased in 2012[8]	2034	0.0	0.0
	Notes [1]: 6.25% (effective rate of 6.3%)[2]	2014-2016	250.0	250.0
	6.1% (effective rate of 6.0%)	2018	200.0	200.0
	5.4% (effective rate of 5.4%)	2021	231.7	231.7
	2.6% (effective rate of 2.7%)	2022	225.0	225.0
	6.55% (effective rate of 6.6%)	2036	250.0	250.0
	6.15% (effective rate of 6.2%)	2037	190.0	190.0
	4.1% (effective rate of 4.2%)	2042	250.0	250.0
Total long-term debt of Tampa Electric			1,650.9	1,702.5
PGS	Notes [1]: 6.1% (effective rate of 7.0%)	2018	50.0	50.0
	5.4% (effective rate of 5.4%)	2021	46.7	46.7
	2.6% (effective rate of 2.7%)	2022	25.0	25.0
	6.15% (effective rate of 6.2%)	2037	60.0	60.0
	4.1% (effective rate of 4.2%)	2042	50.0	50.0
Total long-term debt of PGS			231.7	231.7
Total long-term debt of TECO Energy			2,923.8	2,975.4
Unamortized debt discount, net			(2.7)	(2.7)
Total carrying amount of long-term debt			2,921.1	2,972.7
Less amount due within one year			83.3	0.0
Total long-term debt			$2,837.8	$2,972.7

(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) Guaranteed by TECO Energy.

(4) Tax-exempt securities.

(5) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by TEC. These held variable rate bonds have a par amount of $20.0 million due in 2020.

(6) In September 2013 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $51.6 million due in 2025.

(7) In March 2011 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $75.0 million due in 2030.

(8) In March 2012 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $86.0 million due in 2034.

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 May 5, 2010, the shareholders approved the 2010 Equity Incentive Plan (2010 Plan) as an amendment and restatement of both the company's 2004 Equity Incentive Plan (2004 Plan) and the 1997 Director Equity Plan (1997 Plan, and together with the 2004 Plan, the Old Plans). The 2010 Plan superseded the Old Plans and no additional grants will be made under the Old Plans. The rights of the holders of outstanding options, unvested restricted stock or other outstanding awards under the Old Plans were not affected. The purpose of the 2010 Plan is to attract and retain key employees and non-employee directors, to enable the company to provide equity-based incentives relating to achieving long-range performance goals and to enable award recipients to participate in the long-term growth of the company. The 2010 Plan is administered by the Compensation Committee of the Board of Directors (Committee), which may grant awards to any employee of the company who is capable of contributing significantly to the successful performance of the company. Only the Board of Directors may grant awards to any non-employee members of the Board of Directors.

The 2010 Plan amended the 2004 Plan to reduce the number of shares of common stock subject to grants to 4.0 million shares (a reduction of 3.0 million shares), remove the cap on shares available for stock grant, place various limitations on the terms of awards granted under the 2010 Plan, remove the ability to make awards to consultants of the company and reapprove the business criteria upon which objective performance goals may be established by the Committee to continue to permit the company to take federal tax deductions for performance-based awards made to certain senior officers under Section 162(m) of the tax code.

The types of awards that can be granted under the 2010 Plan include stock options, stock grants and stock equivalents. Stock options were last awarded in 2006 under the Old Plans. Stock grants and time-vested restricted stock are valued at the fair market value on the date of grant, with expense recognized over the vesting period, which is normally three years. Time-vested restricted stock granted to directors vest in one year. Performance-based restricted stock has been granted to officers and employees, with shares potentially vesting after three years. The total awards for performance-based restricted stock vest based on the total return of TECO Energy common stock compared to a peer group of utility stocks. The performance-based grants can vest between 0% and 150% of the original grant. Dividends are paid on all time-vested stock grants during the vesting period. Dividends are accrued during the vesting period on all performance stock granted and paid at vesting date on the shares that vest. 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.

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 accounting guidance for the 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.

Assumptions	*2013*	*2012*	*2011*
Assumptions applicable to performance-based restricted stock			
Risk-free interest rate	0.41%	0.38%	0.96%
Expected lives (in years)	3	3	3
Expected stock volatility	19.04%	20.99%	34.61%
Dividend yield	4.83%	4.78%	4.48%

In 2013, 2012 and 2011, 0.7 million, 1.0 million and 0.8 million shares of restricted stock were granted, respectively, with weighted-average fair values per share of $17.21, $15.96 and $18.44, respectively. The total fair market value of awards vesting during 2013, 2012 and 2011 was $3.5 million, $14.3 million and $13.4 million, respectively, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2013, there was $15.5 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.

The following table provides additional information on compensation costs and income tax benefits and excess tax benefits related to the stock-based compensation awards.

(millions)	*2013*	*2012*	*2011*
Compensation costs (1)	$ 13.5	$ 12.0	$ 9.1
Income tax benefits (1)	5.2	4.6	3.5
Excess tax benefits (2)	0.0	2.6	1.7

(1) Reflected on the Consolidated Statements of Income.

(2) Reflected as financing activities on the Consolidated Statements of Cash Flows.

The aggregate intrinsic value of stock options exercised was $2.4 million, $0.3 million and $1.5 million for the periods ended Dec. 31, 2013, 2012 and 2011, respectively. Cash received from option exercises under all share-based payment arrangements was $6.7 million, $1.1 million and $5.0 million for the periods ended Dec. 31, 2013, 2012 and 2011, respectively. The income tax benefit realized from stock option exercises was $0.8 million, $0.1 million and $0.6 million for the periods ended Dec. 31, 2013, 2012 and 2011, respectively.

A summary of non-vested shares of restricted stock is shown as follows:

Nonvested Restricted Stock

	Time-Based Restricted Stock (1)		**Performance-Based Restricted Stock (1)**	
	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, 2012	592	$ 18.04	1,490	$ 17.13
Granted	237	17.92	496	16.87
Vested	(187)	16.91	(434)	17.20
Forfeited	(4)	17.99	(47)	16.82
Nonvested balance at Dec. 31, 2013	638	$ 18.33	1,505	$ 17.04

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

Stock option transactions are summarized as follows:

Stock Options

	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, 2012	2,087	$15.05		
Granted	0	0.00		
Exercised	(507)	13.22		
Cancelled	(13)	18.87		
Outstanding balance at Dec. 31, 2013 (1)	1,567	$15.62	2	$2.6
Exercisable at Dec. 31, 2013 (1)	1,567	$15.62	2	$2.6
Available for future grant at Dec. 31, 2013	2,725			

(1) Option prices range from $12.01 to $19.01 per share.

As of Dec. 31, 2013, the options outstanding and exercisable are summarized below:

Range of Option Prices (per share)	Option Shares (thousands)	Weighted-Avg. Option Price (per share)	Weighted-Avg. Remaining Contractual Life
$12.01 - $13.56	331	$13.10	1 Years
$16.21 - $19.01	1,236	$16.29	2 Years
Total	1,567	$15.62	2 Years

Dividend Reinvestment Plan

In 1992, TECO Energy implemented a Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy purchased shares on the open market for this plan in 2013, 2012 and 2011, resulting in no increase in equity.

10. Other Comprehensive Income

TECO Energy reported the following OCI (loss) for the years ended Dec. 31, 2013, 2012 and 2011, related to changes in the fair value of cash flow hedges and amortization of unrecognized benefit costs associated with the company's pension plans:

Other Comprehensive Income *(millions)*	Gross	Tax	Net
2013			
Unrealized gain (loss) on cash flow hedges	$ 1.0	$ (0.4)	$ 0.6
Reclassification from AOCI to net income	1.3	(0.5)	0.8
Gain (Loss) on cash flow hedges	2.3	(0.9)	1.4
Amortization of unrecognized benefit costs and other	23.6	(8.8)	14.8
Recognized benefit costs due to settlement	2.6	(1.0)	1.6
Total other comprehensive income (loss)	$ 28.5	$ (10.7)	$ 17.8
2012			
Unrealized (loss) gain on cash flow hedges	$ (7.4)	$ 2.8	$ (4.6)
Reclassification from AOCI to net income	0.6	(0.2)	0.4
(Loss) Gain on cash flow hedges	(6.8)	2.6	(4.2)
Amortization of unrecognized benefit costs and other (1)	(4.8)	0.0	(4.8)
Total other comprehensive (loss) income	$ (11.6)	$ 2.6	$ (9.0)
2011			
Unrealized gain (loss) on cash flow hedges	$ 1.8	$ (0.6)	$ 1.2
Reclassification from AOCI to net income	(3.1)	1.1	(2.0)
(Loss) Gain on cash flow hedges	(1.3)	0.5	(0.8)
Amortization of unrecognized benefit costs and other	(7.9)	3.3	(4.6)
Recognized benefit costs due to settlement	0.9	(0.3)	0.6
Total other comprehensive (loss) income	$ (8.3)	$ 3.5	$ (4.8)

Accumulated Other Comprehensive Loss *(millions) As of Dec. 31,*	*2013*	*2012*
Unrecognized pension losses and prior service credits (2)	$ (20.5)	$ (32.9)
Unrecognized other benefit gains, prior service costs and transition obligations (3)	15.1	11.1
Net unrealized losses from cash flow hedges (4)	(7.8)	(9.2)
Total accumulated other comprehensive loss	$ (13.2)	$ (31.0)

(1) Tax amounts include adjustments made related to Medicare Part D and changes to retirement plan. See **Note 5** for further discussion.
(2) Net of tax benefit of $12.6 million and $20.1 million as of Dec. 31, 2013 and Dec. 31, 2012, respectively.
(3) Net of tax expense of $9.1 million and $6.7 million as of Dec. 31, 2013 and Dec. 31, 2012, respectively.
(4) Net of tax benefit of $4.9 million and $5.8 million as of Dec. 31, 2013 and Dec. 31, 2012, respectively.

11. Earnings Per Share

In accordance with accounting standards for the calculation of EPS, TECO Energy follows the two-class method for computing EPS. These standards define share-based payment awards that participate in dividends prior to vesting as participating securities that should be included in the earnings allocation in computing EPS under the two-class method.

The two-class method of calculating EPS requires TECO Energy to calculate EPS for its common stock and its participating securities (time-vested restricted stock and performance-based restricted stock) based on dividends declared and the pro-rata share each has to undistributed earnings. The application of the two-class method did not have a material effect on TECO Energy's EPS calculations.

(millions, except per share amounts)	*2013*	*2012*	*2011* [(1)]
Basic earnings per share			
Net income from continuing operations	$197.8	$246.0	$250.8
Amount allocated to nonvested participating shareholders	(0.6)	(0.8)	(1.3)
Income before discontinued operations available to common shareholders - Basic	$197.2	$245.2	$249.5
Income (loss) from discontinued operations attributable to TECO Energy, net	($0.1)	($33.3)	$21.8
Amount allocated to nonvested participating shareholders	0.0	0.1	(0.1)
Income (loss) from discontinued operations attributable to TECO Energy available to common shareholders - Basic	($0.1)	($33.2)	$21.7
Net income attributable to TECO Energy	$197.7	$212.7	$272.6
Amount allocated to nonvested participating shareholders	(0.6)	(0.7)	(1.4)
Net income attributable to TECO Energy available to common shareholders - Basic	$197.1	$212.0	$271.2
Average common shares outstanding - Basic	215.0	214.3	213.6
Earnings per share from continuing operations available to common shareholders - Basic	$0.92	$1.14	$1.17
Earnings per share from discontinued operations attributable to TECO Energy available to common shareholders - Basic	$0.00	($0.15)	$0.10
Earnings per share attributable to TECO Energy available to common shareholders - Basic	**$0.92**	**$0.99**	**$1.27**
Diluted earnings per share			
Net income from continuing operations	$197.8	$246.0	$250.8
Amount allocated to nonvested participating shareholders	(0.6)	(0.8)	(1.3)
Income before discontinued operations available to common shareholders - Diluted	$197.2	$245.2	$249.5
Income (loss) from discontinued operations attributable to TECO Energy, net	($0.1)	($33.3)	$21.8
Amount allocated to nonvested participating shareholders	0.0	0.1	(0.1)
Income (loss) from discontinued operations attributable to TECO Energy available to common shareholders - Diluted	($0.1)	($33.2)	$21.7
Net income attributable to TECO Energy	$197.7	$212.7	$272.6
Amount allocated to nonvested participating shareholders	(0.6)	(0.7)	(1.4)
Net income attributable to TECO Energy available to common shareholders - Diluted	$197.1	$212.0	$271.2
Unadjusted average common shares outstanding - Diluted	215.0	214.3	213.6
Assumed conversion of stock options, unvested restricted stock and contingent performance shares, net	0.5	0.7	1.5
Average common shares outstanding - Diluted	215.5	215.0	215.1
Earnings per share from continuing operations available to common shareholders - Diluted	$0.92	$1.14	$1.17
Earnings per share from discontinued operations attributable to TECO Energy available to common shareholders - Diluted	$0.00	($0.15)	$0.10
Earnings per share attributable to TECO Energy available to common shareholders - Diluted	**$0.92**	**$0.99**	**$1.27**
Anti-dilutive shares	0.0	0.4	1.7

(1) All prior periods presented reflect the classification of TECO Guatemala as discontinued operations (see **Note 19**).

12. Commitments and Contingencies

Legal Contingencies

From time to time, TECO Energy and its subsidiaries are involved in various 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 accounting standards for contingencies to provide for matters that are probable of resulting in an estimable 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, financial condition or cash flows.

Legal Proceedings

In November 2010, heavy equipment operated at a road construction site being conducted by Posen Construction, Inc. struck a natural gas line causing a rupture and ignition of the gas and an outage in the natural gas service to Lee and Collier counties, Florida. In December 2010, two commercial PGS customers filed a purported class action in Lee County Circuit Court, Florida against PGS on behalf of PGS commercial customers affected by the outage, seeking damages for loss of revenue and other costs related to the gas outage. Posen Construction, Inc., the company conducting construction at the site where the incident occurred, is also a defendant in the action. In June 2013, the court denied the plaintiffs' motion for class certification and dismissed the plaintiffs' underlying claim against PGS. The Court's order is now final and not appealable. PGS filed suit in April 2011 against Posen Construction, Inc. in Federal Court for the Middle District of Florida to recover damages for repair and restoration relating to the incident and Posen Construction, Inc. counter-claimed against PGS alleging negligence. In the first quarter of 2014, the parties entered into a settlement agreement that resolves the claims of the parties. In addition, the suit filed in November 2011 by the Posen Construction, Inc. employee operating the heavy equipment involved in the incident in Lee County Circuit Court against PGS, Posen Construction, Inc. and a PGS contractor involved in the project, seeking damages for his injuries, also remains pending.

In addition, three former or inactive TEC employees are maintaining a suit against TEC in Hillsborough County Circuit Court, Florida for personal injuries allegedly caused by exposure to a chemical substance at one of TEC's power stations. The suit was originally filed in 2002, and the trial judge allowed the plaintiffs to seek punitive damages in connection with their case. In the first quarter of 2014, the attorneys for the plaintiffs withdrew from representation. A trial is expected sometime in 2014.

The company believes the claims in each of the pending actions described above in this item are without merit and intends to defend each matter vigorously. The company is unable at this time to estimate the possible loss or range of loss with respect to these matters.

Environmental Protection Agency Section 114 Letter

On Feb. 11, 2013, TEC received an information request from the EPA under Section 114(a) of the CAA seeking documents and other information concerning the compliance status of its sulfuric acid plant at its Polk Power Station in Polk County, Florida with the "New Source Review" requirements of the CAA. The request received by TEC appears to be part of a broader EPA national enforcement initiative focusing on sulfuric acid plants. TEC cannot predict at this time what the scope of this matter will ultimately be or the range of outcomes, and therefore it is not able to estimate the possible loss or range of loss, if any, with respect to this matter. TEC responded with the requested information on April 26, 2013 and has not received any response from the EPA on this matter.

Environmental Protection Agency Administrative Order

In December 2010, Clintwood Elkhorn Mining Company, a subsidiary of TECO Coal, received an Administrative Order from the EPA relating to the discharge of wastewater associated with inactive mining operations in Pike County, Kentucky. A consent agreement and final order with the EPA with respect to this matter became effective on July 23, 2013, the costs associated with which were not material to the financial results or financial position of TECO Energy.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and Peoples Gas divisions, is a 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, 2013, TEC has estimated its ultimate financial liability to be $40.4 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other" on the Consolidated Balance Sheets. 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 portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC'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.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's actual percentage of the remediation costs.

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. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Long-Term Commitments

TECO Energy has commitments under long-term leases, primarily for building space, capacity payments, office equipment and heavy equipment. Total rental expense for these leases, included in "Regulated operations and maintenance – Other", "Operation & maintenance other expense – Mining related costs" and "Operation & maintenance other expense – Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2013, 2012 and 2011, totaled $7.6 million, $8.1 million and $10.2 million, respectively. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year and capacity payments under PPAs at Dec. 31, 2013:

Future Minimum Lease and Capacity Payments

(millions)	*Capacity Payments*	*Operating Leases*	*Total*
Year ended Dec. 31:			
2014	$14.8	$5.0	$19.8
2015	14.9	3.9	18.8
2016	14.6	2.6	17.2
2017	9.9	2.4	12.3
2018	10.1	2.2	12.3
Thereafter	0.0	13.4	13.4
Total future minimum payments	$64.3	$29.5	$93.8

Guarantees and Letters of Credit

TECO Energy accounts for guarantees in accordance with the applicable accounting standards. 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) are likely to be subject to the recognition and measurement, as well as the disclosure provisions. 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, 2013 are as follows:

Guarantees-TECO Energy

(millions) Guarantees for the Benefit of:	*2014*	*2015-2018*	*After 2018* (1)	*Total*	*Liabilities Recognized at Dec. 31, 2013*
TECO Coal					
Fuel purchase related (2)	$0.8	$0.7	$4.0	$5.5	$1.5
Other subsidiaries					
Guaranty under sale agreement (3)	0.0	5.0	0.0	5.0	5.0
Fuel sales and transportation (2)	10.0	0.0	91.8	101.8	0.1
Total	$10.8	$5.7	$95.8	$112.3	$6.6

Letters of Credit-Tampa Electric Company

(millions) Letters of Credit for the Benefit of:	*2014*	*2015-2018*	*After 2018* (1)	*Total*	*Liabilities Recognized at Dec. 31, 2013*
Tampa Electric (2)	$0.0	$0.0	$0.7	$0.7	$0.1

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2018.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy under these agreements at Dec. 31, 2013. The obligations under these letters of credit and guarantees include net accounts payable and net derivative liabilities.

(3) The liability recognized relates to an indemnification provision for an uncertain tax position at TCAE that was provided for in the purchase agreement. See **Note 19** for additional information.

Financial Covenants

In order to utilize their respective bank credit facilities, TECO Energy, TECO Finance and TEC must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, TECO Finance, TEC, and the other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2013, TECO Energy, TECO Finance, TEC, and the other operating companies were in compliance with all required financial covenants.

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 $1.7 million, $1.3 million and $1.3 million for the years ended Dec. 31, 2013, 2012 and 2011, respectively, to Ausley McMullen, P.A. of which Mr. DuBose Ausley (who was a director of TECO Energy, until his retirement from the Board in May 2013) was an employee. Other transactions were not material for the years ended Dec. 31, 2013, 2012 and 2011. No material balances were payable as of Dec. 31, 2013 or 2012.

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 the accounting guidance for 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.

Segment Information

(millions)	Tampa Electric	PGS	TECO Coal		TECO Guatemala	Other & Eliminations	TECO Energy
2013							
Revenues - external	$1,949.6	$392.7	$496.2		$0.0	$12.8	$2,851.3
Sales to affiliates	0.9	0.8	0.0		0.0	(1.7)	0.0
Total revenues	1,950.5	393.5	496.2		0.0	11.1	2,851.3
Depreciation and amortization	238.8	51.5	37.7		0.0	1.5	329.5
Total interest charges (1)	91.8	13.5	5.5		0.0	56.1	166.9
Internally allocated interest (1)	0.0	0.0	6.4		0.0	(6.4)	0.0
Provision for income taxes	116.9	21.9	(3.6)		0.0	(26.3)	108.9
Net income from continuing operations	190.9	34.7	9.0		0.0	(36.8)	197.8
Discontinued operations attributable to TECO, net of tax	0.0	0.0	0.0		0.0	(0.1)	(0.1)
Net income attributable to TECO Energy	190.9	34.7	9.0		0.0	(36.9)	197.7
Total assets	6,126.9	1,021.2	316.3	(3)	0.0	(16.4)	7,448.0
Capital expenditures	428.6	79.0	22.4		0.0	2.4	532.4
2012							
Revenues - external	$1,980.7	$396.6	$608.9		$0.0	$10.4	$2,996.6
Sales to affiliates	0.6	2.3	0.0		0.0	(2.9)	0.0
Total revenues	1,981.3	398.9	608.9		0.0	7.5	2,996.6
Depreciation and amortization	237.6	50.6	41.0		0.0	1.4	330.6
Total interest charges (1)	109.8	16.0	7.1		0.0	50.6	183.5
Internally allocated interest (1)	0.0	0.0	6.8		0.0	(6.8)	0.0
Provision for income taxes	120.2	21.5	15.7		0.0	(19.6)	137.8
Net income from continuing operations	193.1	34.1	50.2		0.0	(31.4)	246.0
Discontinued operations attributable to TECO, net of tax	0.0	0.0	0.0		(29.3)	(4.0)	(33.3)
Net income attributable to TECO Energy	193.1	34.1	50.2		(29.3)	(35.4)	212.7
Total assets	6,042.3	1,009.9	356.6	(3)	164.9	(238.8)	7,334.9
Capital expenditures	361.7	97.3	36.3		8.6	1.2	505.1
2011							
Revenues - external	$2,019.3	$450.5	$733.0		$0.0	$7.1	$3,209.9
Sales to affiliates	1.3	3.0	0.0		0.0	(4.3)	0.0
Total revenues	2,020.6	453.5	733.0		0.0	2.8	3,209.9
Depreciation and amortization	222.1	48.4	45.3		0.0	1.4	317.2
Total interest charges (1)	121.8	17.7	6.9		0.0	51.0	197.4
Internally allocated interest (1)	0.0	0.0	6.7		0.0	(6.7)	0.0
Provision for income taxes	124.8	20.6	15.4		0.0	(18.1)	142.7
Net income from continuing operations	202.7	32.6	51.5		0.0	(36.0)	250.8
Discontinued operations attributable to TECO, net of tax (2)	0.0	0.0	0.0		22.4	(0.6)	21.8
Net income attributable to TECO Energy	202.7	32.6	51.5		22.4	(36.6)	272.6
Goodwill	0.0	0.0	0.0		55.4	0.0	55.4
Total assets	5,925.9	932.0	385.2	(3)	304.1	(240.0)	7,307.2
Capital expenditures	314.9	71.9	56.6		7.2	3.5	454.1

(1) Segment net income is reported on a basis that includes internally allocated financing costs. Total interest charges include internally allocated interest costs that for 2013 and 2012 were at a pretax rate of 6.00%, and for 2011 were at a pretax rate of 6.25%, based on an average of each subsidiary's equity and indebtedness to TECO Energy assuming a 50/50 debt/equity capital structure.

(2) All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for TECO Guatemala and certain charges at Parent that directly relate to TECO Guatemala. See **Note 19**.

(3) The carrying value of mineral rights as of Dec. 31, 2013, 2012 and 2011 was $12.1 million, $13.4 million and $15.0 million, respectively.

Tampa Electric provides retail electric utility services to almost 700,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for almost 350,000 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.

15. Asset Retirement Obligations

TECO Energy accounts for AROs under the applicable accounting standards. An 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 AROs for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities at TECO Coal. The majority of obligations arise from environmental remediation and restoration activities for coal-related operations. At Dec. 31, 2013 and 2012, these obligations totaled $23.8 million and $23.6 million, respectively.

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. At Dec. 31, 2013 and 2012, these obligations totaled $4.8 million and $5.0 million, respectively.

For the years ended Dec. 31, 2013, 2012 and 2011, TECO Energy recognized $1.4 million annually of accretion expense associated with AROs in “Depreciation and amortization” on the Consolidated Statements of Income. For the year ended Dec. 31, 2013, $1.4 million of liabilities settled resulted primarily from reclamation costs related to mine closures. For the year ended Dec. 31, 2012, $29.1 million of liabilities settled resulted primarily from asbestos abatement and other dismantling at the generating stations at Tampa Electric.

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

	Dec. 31,	
(millions)	*2013*	*2012*
Beginning balance	$28.6	$53.8
Additional liabilities	0.1	0.7
Liabilities settled	(1.4)	(29.1)
Accretion expense	1.4	1.4
Revisions to estimated cash flows	(0.3)	0.0
Other [(1)]	0.2	1.8
Ending balance	$28.6	$28.6

(1) Accretion recorded as a deferred regulatory asset.

16. Accounting for Derivative Instruments and Hedging Activities

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; and
- To limit the exposure to price fluctuations for physical purchases of fuel at TECO Coal.

TECO Energy and its affiliates use derivatives only to reduce normal operating and market risks, not for speculative purposes. TEC'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 accounting standards for 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 (see **Note 17**). 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 loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of the instrument's settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the market change of the amount paid or received on the underlying physical transaction.

The company applies the accounting standards for regulated operations to financial instruments used to hedge the purchase of natural gas for its regulated companies. These standards, in accordance with the FPSC, permit the changes in fair value of natural gas derivatives to be recorded as regulatory assets or liabilities reflecting the impact of hedging activities on the fuel recovery clause. As a result, these changes are not recorded in OCI (see **Note 3**).

The company's physical contracts qualify for the NPNS exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if the company deems the counterparty creditworthy, if the counterparty owns or controls resources within the proximity to allow for physical delivery of the commodity, if the company intends to receive physical delivery and if the transaction is reasonable in relation to the company's business needs. As of Dec. 31, 2013, all of the company's physical contracts qualify for the NPNS exception.

The following table presents the derivatives that are designated as cash flow hedges at Dec. 31, 2013 and Dec. 31, 2012:

Total Derivatives

(millions)	*Dec. 31, 2013*	*Dec. 31, 2012*
Current assets	$9.7	$0.0
Long-term assets	0.3	0.2
Total assets	$10.0	$0.2
Current liabilities	$0.1	$14.6
Long-term liabilities	0.2	0.6
Total liabilities	$0.3	$15.2

The following table presents the gross amounts of derivatives and their related offset amounts as permitted by their respective master netting agreements at Dec. 31, 2013 and Dec. 31, 2012. There was no collateral posted with or received from any counterparties.

Offsetting of Derivative Assets and Liabilities
(millions)

	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
Dec. 31, 2013			
Description			
Derivative assets	$ 10.5	$ (0.5)	$ 10.0
Derivative liabilities	$ (0.8)	$ 0.5	$ (0.3)
Dec. 31, 2012			
Description			
Derivative assets	$ 1.0	$ (0.8)	$ 0.2
Derivative liabilities	$ (16.0)	$ 0.8	$ (15.2)

The following table presents the derivative cash flow hedges of diesel fuel contracts at Dec. 31, 2013 and 2012 to limit the exposure to changes in the market price for diesel fuel:

Diesel Fuel Derivatives

(millions)	*Dec. 31, 2013*	*Dec. 31, 2012*
Current assets	$0.2	$0.0
Long-term assets	0.0	0.0
Total assets	$0.2	$0.0
Current liabilities	$0.1	$0.5
Long-term liabilities	0.0	0.4
Total liabilities	$0.1	$0.9

The following table presents the derivative hedges of natural gas contracts at Dec. 31, 2013 and 2012 to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers:

Natural Gas Derivatives (1)

(millions)	*Dec. 31, 2013*	*Dec. 31, 2012*
Current assets	$9.5	$0.0
Long-term assets	0.3	0.2
Total assets	$9.8	$0.2
Current liabilities	$0.0	$14.1
Long-term liabilities	0.2	0.2
Total liabilities	$0.2	$14.3

(1) Amounts presented above are on a gross basis, with asset and liability positions netted by counterparty in accordance with accounting standards for derivatives and hedging.

The ending balance in AOCI related to the cash flow hedges and previously settled interest rate swaps at Dec. 31, 2013 is a net loss of $7.8 million after tax and accumulated amortization. This compares to a net loss of $9.2 million in AOCI after tax and accumulated amortization at Dec. 31, 2012.

The following table presents the fair values and locations of derivative instruments recorded on the balance sheet at Dec. 31, 2013 and 2012:

Derivatives Designated As Hedging Instruments

	Asset Derivatives		Liability Derivatives	
(millions)	*Balance Sheet*	*Fair*	*Balance Sheet*	*Fair*
at Dec. 31, 2013	*Location*	*Value*	*Location*	*Value*
Commodity Contracts:				
Diesel fuel derivatives:				
Current	Derivative assets	$0.2	Derivative liabilities	$0.1
Long-term	Derivative assets	0.0	Derivative liabilities	0.0
Natural gas derivatives:				
Current	Derivative assets	9.5	Derivative liabilities	0.0
Long-term	Derivative assets	0.3	Derivative liabilities	0.2
Total derivatives designated as hedging instruments		$10.0		$0.3

	Asset Derivatives		Liability Derivatives	
(millions)	*Balance Sheet*	*Fair*	*Balance Sheet*	*Fair*
at Dec. 31, 2012	*Location*	*Value*	*Location*	*Value*
Commodity Contracts:				
Diesel fuel derivatives:				
Current	Derivative assets	$0.0	Derivative liabilities	$0.5
Long-term	Derivative assets	0.0	Derivative liabilities	0.4
Natural gas derivatives:				
Current	Derivative assets	0.0	Derivative liabilities	14.1
Long-term	Derivative assets	0.2	Derivative liabilities	0.2
Total derivatives designated as hedging instruments		$0.2		$15.2

The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism on the Consolidated Balance Sheets as of Dec. 31, 2013 and 2012:

Energy Related Derivatives

	Asset Derivatives		Liability Derivatives	
(millions) *at Dec. 31, 2013*	Balance Sheet Location (1)	Fair Value	Balance Sheet Location (1)	Fair Value
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$9.5	Regulatory assets	$0.0
Long-term	Regulatory liabilities	0.3	Regulatory assets	0.2
Total		$9.8		$0.2

(millions) *at Dec. 31, 2012*	Balance Sheet Location (1)	Fair Value	Balance Sheet Location (1)	Fair Value
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$0.0	Regulatory assets	$14.1
Long-term	Regulatory liabilities	0.2	Regulatory assets	0.2
Total		$0.2		$14.3

(1) Natural gas derivatives are deferred in accordance with accounting standards for regulated operations and all increases and decreases in the cost of natural gas supply are passed on to customers with the fuel recovery clause mechanism. As gains and losses are realized in future periods, they will be recorded as fuel costs in the Consolidated Statements of Income.

Based on the fair value of the instruments at Dec. 31, 2013, net pretax gains of $9.5 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The following table presents the effect of hedging instruments on OCI and income for the years ended Dec. 31:

(millions) Derivatives in Cash Flow Hedging Relationships	Amount of Gain/(Loss) on Derivatives Recognized in OCI Effective Portion (1)	Location of Gain/(Loss) Reclassified From AOCI Into Income Effective Portion (1)	Gain/(Loss) Reclassified From AOCI Into Income
2013			
Interest rate contracts:	$0.0	Interest expense	($0.9)
Commodity contracts:			
Diesel fuel derivatives	0.6	Mining related costs	0.1
Total	$0.6		($0.8)
2012			
Interest rate contracts:	($4.9)	Interest expense	($0.8)
Commodity contracts:			
Diesel fuel derivatives	0.3	Mining related costs	0.4
Total	($4.6)		($0.4)
2011			
Interest rate contracts:	$0.0	Interest expense	($0.7)
Commodity contracts:			
Diesel fuel derivatives	1.2	Mining related costs	2.7
Total	$1.2		$2.0

(1) Changes in OCI and AOCI are reported in after-tax dollars.

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or period during which the hedged transaction affects earnings. Gains and losses on the derivatives representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For the years ended Dec. 31, 2013, 2012 and 2011, all hedges were effective.

The following table presents the derivative activity for instruments classified as qualifying cash flow hedges for the years ended Dec. 31:

(millions)	Fair Value Asset/(Liability)	Amount of Gain/(Loss) Recognized in OCI [1]	Amount of Gain/(Loss) Reclassified From AOCI Into Income [1]
2013			
Interest rate swaps	$0.0	$0.0	($0.9)
Diesel fuel derivatives	0.1	0.6	0.1
Total	$0.1	$0.6	($0.8)
2012			
Interest rate swaps	$0.0	($4.9)	($0.8)
Diesel fuel derivatives	(0.9)	0.3	0.4
Total	($0.9)	($4.6)	($0.4)
2011			
Interest rate swaps	$0.0	$0.0	($0.7)
Diesel fuel derivatives	(0.3)	1.2	2.7
Total	($0.3)	$1.2	$2.0

(1) Changes in OCI and AOCI are reported in after-tax dollars.

The maximum length of time over which the company is hedging its exposure to the variability in future cash flows extends to Dec. 31, 2014 for financial diesel fuel contracts and Dec. 31, 2015 for financial natural gas contracts. The following table presents by commodity type the company's derivative volumes that, as of Dec. 31, 2013, are expected to settle during the 2014 and 2015 fiscal years:

(millions)	Diesel Fuel Contracts (Gallons)		Natural Gas Contracts (MMBTUs)	
Year	Physical	Financial	Physical	Financial
2014	0.0	2.0	0.0	36.9
2015	0.0	0.0	0.0	7.6
Total	0.0	2.0	0.0	44.5

The company is exposed to credit risk primarily through entering into derivative instruments with counterparties to limit its exposure to the commodity price fluctuations associated with diesel fuel and natural gas. Credit risk is the potential loss resulting from a counterparty's nonperformance under an agreement. The company manages credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement and exposure monitoring and mitigation.

It is possible that volatility in commodity prices could cause the company to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the company could suffer a material financial loss. However, as of Dec. 31, 2013, substantially all of the counterparties with transaction amounts outstanding in the company's energy portfolio were rated investment grade by the major rating agencies. The company assesses credit risk internally for counterparties that are not rated.

The company has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. The company generally enters into the following master arrangements: (1) EEI agreements - standardized power sales contracts in the electric industry; (2) ISDA agreements - standardized financial gas and electric contracts; and (3) NAESB agreements - standardized physical gas contracts. The company believes that entering into such agreements reduces the risk from default by creating contractual rights relating to creditworthiness, collateral and termination.

The company has implemented procedures to monitor the creditworthiness of its counterparties and to consider nonperformance risk in determining the fair value of counterparty positions. Net liability positions are generally not adjusted as the company uses derivative transactions as hedges and has the ability and intent to perform under each of these contracts. In the instance of net asset positions, the company considers general market conditions and the observable financial health and outlook of specific counterparties in evaluating the potential impact of nonperformance risk to derivative positions. As of Dec. 31, 2013, substantially all positions with counterparties were net assets.

Certain TECO Energy derivative instruments contain provisions that require the company's debt, or in the case of derivative instruments where TEC is the counterparty, TEC's debt, to maintain an investment grade credit rating from any or all of the major credit rating agencies. If debt ratings, including TEC's, were to fall below investment grade, it could trigger these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The company has no other contingent risk features associated with any derivative instruments.

The table below presents the fair value of the overall contractual contingent liability positions for the company's derivative activity at Dec. 31, 2013:

Contingent Features

(millions)	Fair Value Asset/ (Liability)	Derivative Exposure Asset/ (Liability)	Posted Collateral
Credit Rating	($0.1)	($0.1)	$0.0

17. Fair Value Measurements

Items Measured at Fair Value on a Recurring Basis

The following tables set forth by level within the fair value hierarchy the company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of Dec. 31, 2013 and 2012. As required by accounting standards for fair value measurements, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The company's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For natural gas and diesel fuel swaps, the market approach was used in determining fair value.

Recurring Fair Value Measures

	At fair value as of Dec. 31, 2013			
(millions)	Level 1	Level 2	Level 3	Total
Assets				
Natural gas swaps	$0.0	$9.8	$0.0	$9.8
Diesel fuel swaps	0.0	0.2	0.0	0.2
Total	$0.0	$10.0	$0.0	$10.0
Liabilities				
Natural gas swaps	$0.0	$0.2	$0.0	$0.2
Diesel fuel swaps	0.0	0.1	0.0	0.1
Total	$0.0	$0.3	$0.0	$0.3

	At fair value as of Dec. 31, 2012			
(millions)	Level 1	Level 2	Level 3	Total
Assets				
Natural gas swaps	$0.0	$0.2	$0.0	$0.2
Diesel fuel swaps	0.0	0.0	0.0	0.0
Total	$0.0	$0.2	$0.0	$0.2
Liabilities				
Natural gas swaps	$0.0	$14.3	$0.0	$14.3
Diesel fuel swaps	0.0	0.9	0.0	0.9
Total	$0.0	$15.2	$0.0	$15.2

Natural gas and diesel fuel swaps are OTC swap instruments. The primary pricing inputs in determining the fair value of these swaps are the NYMEX quoted closing prices of exchange-traded instruments. These prices are applied to the notional amounts of active positions to determine the reported fair value (see **Note 16**).

The company considered the impact of nonperformance risk in determining the fair value of derivatives. The company considered the net position with each counterparty, past performance of both parties, the intent of the parties, indications of credit deterioration and whether the markets in which the company transacts have experienced dislocation. At Dec. 31, 2013, the fair value of derivatives was not materially affected by nonperformance risk. The company's net positions with substantially all counterparties were asset positions. There were no Level 3 assets or liabilities during the 2013 or 2012 fiscal years.

18. Variable Interest Entities

The determination of a VIE's primary beneficiary is the enterprise that has both 1) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and 2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

TEC has entered into multiple PPAs with wholesale energy providers in Florida to ensure the ability to meet customer energy demand and to provide lower cost options in the meeting of this demand. These agreements range in size from 117 MW to 370 MW of available capacity, are with similar entities and contain similar provisions. Because some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy, these agreements meet the definition of being VIEs. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. TEC has reviewed these risks and has determined that the owners of these entities have retained the majority of these risks over the expected life of the underlying generating assets, have the power to direct the most significant activities, the obligation or right to absorb losses or benefits and hence remain the primary beneficiaries. As a result, TEC is not required to consolidate any of these entities. TEC purchased $22.1 million, $75.8 million and $81.2 million, under these PPAs for the three years ended Dec. 31, 2013, 2012 and 2011, respectively.

In one instance, TEC's agreement with an entity for 370 MW of capacity was entered into prior to Dec. 31, 2003, the effective date of these standards. Under these standards, TEC is required to make an exhaustive effort to obtain sufficient information to determine if this entity is a VIE and which holder of the variable interests is the primary beneficiary. The owners of this entity are not willing to provide the information necessary to make these determinations, have no obligation to do so and the information is not available publicly. As a result, TEC is unable to determine if this entity is a VIE and, if so, which variable interest holder, if any, is the primary beneficiary. TEC has no obligation to this entity beyond the purchase of capacity; therefore, the maximum exposure for TEC is the obligation to pay for such capacity under terms of the PPA at rates that could be unfavorable to the wholesale market. TEC purchased $46.6 million and $34.4 million for the two years ended Dec. 31, 2012 and 2011, respectively. This PPA expired on Dec. 31, 2012.

The company does not provide any material financial or other support to any of the VIEs it is involved with, nor is the company under any obligation to absorb losses associated with these VIEs. In the normal course of business, the company's involvement with these VIEs does not affect its Consolidated Balance Sheets, Statements of Income or Cash Flows.

19. Discontinued Operations

On Aug. 7, 2012, TECO Energy received an offer from Renewable Energy Investments Guatemala Limited (REIN), a wholly-owned subsidiary of Sur Eléctrica Holding Limited (SUR), to purchase the independent power projects in Guatemala and certain affiliated Guatemala companies. SUR and REIN are international business companies organized under the laws of the Commonwealth of the Bahamas. On Sept. 27, 2012, an indirect wholly-owned subsidiary of TECO Energy, Inc., TECO Guatemala Holdings II, LLC (TGH), entered into an equity purchase agreement with SUR, and two equity purchase agreements with REIN (the three equity purchase agreements are collectively referred to herein as the "PAs"). Pursuant to the PA with SUR, TGH agreed to sell all of its ownership interests in TPS Guatemala One, Ltd. (TPS GO) for $12.5 million, and pursuant to the PAs with REIN, it agreed to sell all of its ownership interests in (i) TPS San José International, Inc. (TPS SJI) for $213.5 million and (ii) TECO Guatemala Services, Ltd. (TGS) for $1.5 million (TPS GO, TPS SJI and TGS are collectively referred to herein as the Disposal Group). The companies in the Disposal Group are the ultimate parent companies of TCAE, CGESJ, TEMSA, and TPS Operaciones de Guatemala, Limitada (TPSO), the owner of certain local real estate assets and the employer of the local employees. The total purchase price for the Disposal Group under the PAs was $227.5 million.

The sale of TPS GO, which owns 96.06% of TCAE, closed on Sept. 27, 2012. An affiliate of the party that controlled the remaining interest in TCAE (the "noncontrolling interest holder") held certain contractual rights with respect to TEMSA and CGESJ, including a right of first offer. The noncontrolling interest holder was also granted the opportunity to purchase TGS since the operations of TPSO are integral to the operations of TEMSA and CGESJ. The noncontrolling interest holder exercised the right of first offer for TPS SJI and elected to purchase TGS by executing PAs similar to the PAs with REIN on Oct. 17, 2012 and Oct. 26, 2012, respectively. The sales of TPS SJI and TGS to the noncontrolling interest holder closed on Dec. 19, 2012.

As a result of the PAs, the TECO Guatemala segment is accounted for as a discontinued operation at Dec. 31, 2013. The following table provides selected components of discontinued operations:

Components of income from discontinued operations attributable to TECO Energy	*Twelve months ended Dec. 31,*		
(millions)	2013	2012	2011
Revenues	$0.0	$114.2	$133.5
(Loss) income from operations	(0.2)	27.7	33.7
Loss on assets sold, including transaction costs	0.0	(38.3)	(0.4)
Income (loss) from discontinued operations	(0.2)	(10.6)	33.3
Provision (benefit) for income taxes	(0.1)	22.4	11.2
Income (loss) from discontinued operations, net	(0.1)	(33.0)	22.1
Less: Income from discontinued operations attributable to noncontrolling interest	0.0	0.3	0.3
Income (loss) from discontinued operations attributable to TECO Energy, net	($0.1)	($33.3)	$21.8

The provision for income taxes line item includes an after-tax charge of $22.9 million in 2012 associated with foreign tax credits. The 2012 charge is a result of the sales of the Disposal Group which eliminate future foreign source income that would be required to utilize these credits.

The PAs contain customary representations, warranties and covenants. The PAs also contain indemnification provisions subject to specified limitations as to time and amount, including an indemnification provision related to an uncertain tax position related to TCAE.

On Dec. 19, 2013, the ICSID tribunal hearing TGH's arbitration claim against the Republic of Guatemala under DR-CAFTA issued an award in the case. The ICSID tribunal unanimously found in favor of TGH and awarded damages of approximately U.S. $21.1 million, plus interest from Oct. 21, 2010 at a rate equal to the prime rate plus 2%. In addition, the tribunal ruled that Guatemala must reimburse TGH for approximately $7.5 million of the costs it incurred in pursuing the arbitration.

The ICSID tribunal found that Guatemala breached its treaty obligation to grant TGH fair and equitable treatment under the terms of the DR-CAFTA, thereby causing damages to TGH for which it is entitled to compensation. In sum, the tribunal found that Guatemala's repudiation of fundamental regulatory principles applying to the tariff review process was arbitrary and breached elementary standards of due process in administrative matters.

Each party has 120 days from the date of the award to seek annulment of the decision. Pending the outcome of a potential annulment filing, results in 2013 do not reflect any benefit of this decision.

20. Goodwill and Asset Impairments

Under the accounting guidance for goodwill, goodwill is not subject to amortization. Rather, goodwill with an indefinite life is subject to an annual assessment for impairment at the reporting unit level. Reporting units are generally determined at 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. The goodwill formerly on the company's balance sheet related to the TECO Guatemala segment and arose from the purchase of multiple entities as a result of the company's investments in the Alborada (held by TPS GO) and San José (held by TPS SJI) power plants. Since these reporting units were one level below the operating segment level, discrete cash flow information was available, and management regularly reviewed their operating results separately, these were the reporting unit level at which potential impairment was tested.

Prior to the sales in 2012 (see **Note 19**), goodwill balances for the TPS GO and TPS SJI reporting units were written down to their implied fair value calculated using the offers from SUR and REIN. Although these were binding quoted prices, the fair value measurements were considered Level 2 measurements since the market was not active as defined by accounting standards (i.e. transactions for these assets were too infrequent to provide pricing information on an ongoing basis). Prior to receiving the offers from REIN and SUR, the fair values of TPS GO's and TPS SJI's goodwill amounts were calculated using the discounted cash flows appropriate for the business model of each reporting unit. Discounted cash flows were formerly the best estimates of fair value of the reporting units, since neither a sale nor a similar transaction was readily observed in the marketplace for many years due to an inactive market.

The changes in the carrying amount of goodwill for the year ended Dec. 31, 2012 are represented in the following table:

(millions)	TPS GO	TPS SJI	Total
Balance as of Jan. 1, 2012	$3.1	$52.3	$55.4
Impairment losses, pretax	(3.1)	(12.1)	(15.2)
Goodwill written off upon sale, pretax	0.0	(40.2)	(40.2)
Balance as of Dec. 31, 2012	$0.0	$0.0	$0.0

The Impairment losses, pretax and Goodwill written off upon sale, pretax amounts from the table above are recorded in the Income (loss) from discontinued operations line item in the **Consolidated Statements of Income** and the Loss (gain) on sales of business/assets, pretax line item in the **Consolidated Statements of Cash Flows** for the year ended Dec. 31, 2012.

The company accounts for long-lived asset impairments in accordance with the accounting guidance for long-lived assets, which requires that long-lived assets held and used be tested for recoverability whenever events or changes in circumstances indicate that its carrying value may not be recoverable, and assets held for sale be recorded at the lower of its carrying amount or fair value less cost to sell. An asset is considered not recoverable if its carrying value exceeds the sum of its undiscounted expected cash flows. If it is determined that the carrying value is not recoverable and its carrying value exceeds its fair value, an impairment charge is made and the value of the asset is reduced to its fair value.

Prior to the sale of TGS, the company recorded a long-lived asset pretax impairment charge of $2.0 million. This amount is recorded in the Income (loss) from discontinued operations line item in the **Consolidated Statements of Income** and the Loss (gain) on sales of business/assets, pretax line item in the **Consolidated Statements of Cash Flows** for the year ended Dec. 31, 2012. The fair value was calculated using the offer from REIN. Although it was a binding quoted price, the fair value measurement was considered a Level 2 measurement since the market was not active as defined by accounting standards (i.e. transactions for these assets are too infrequent to provide pricing information on an ongoing basis).

Additionally, in both 2012 and 2013, TECO Coal temporarily idled some of its mines due to the softened coal market. As a result, the company performed impairment analyses in each fourth quarter on the mining complexes with closed mines and the coal reserves. The company used an undiscounted cash flows approach in determining the recoverability amount of the assets in accordance with applicable accounting guidance. All assets were determined to have carrying values that are recoverable; therefore, no impairment charge was deemed necessary. Additionally, the company performed sensitivity analyses for the effects of inflation and noted that if inflation affected costs more than revenues by one percent each year, all assets would still be recoverable.

21. Dispositions

Sale of San José and Alborada

On Sept. 27, 2012, TECO Guatemala entered into an agreement to sell all of the equity interests in the Alborada and San José power stations and their related facilities and operations in Guatemala for a total purchase price of $227.5 million in cash. The TECO Guatemala segment was accounted for as discontinued operations beginning in the third quarter of 2012. For more information regarding the sale, see **Note 19**.

While TECO Energy and its subsidiaries will no longer have assets or operations in Guatemala, its subsidiary, TECO Guatemala Holdings, LLC, has retained its rights under its arbitration claim filed against the Republic of Guatemala in October 2010 under the DR – CAFTA. For more information on the claim, see **Note 19**.

Net proceeds from the sale of all Guatemalan operations, after estimated transaction-related costs and the $25.3 million repayment of the San José power station project debt, were approximately $197.0 million. The sale resulted in an after-tax book loss and an after-tax charge associated with foreign tax credits of $28.6 million and $22.9 million, respectively.

22. Pending Acquisition of New Mexico Gas Company

Stock Purchase Agreement

On May 25, 2013, the company entered into an SPA by and among the company, NMGI and Continental Energy Systems LLC (CES). NMGI is the parent company of NMGC. Pursuant to the terms of and subject to the conditions set forth in the SPA, the company will acquire from CES all of the outstanding capital stock of its subsidiary, NMGI, for an aggregate purchase price of $950 million, which includes the assumption of $200 million of senior secured notes at NMGC. The purchase price is subject to certain closing adjustments in accordance with the terms of the SPA. The permanent financing is expected to be a combination of TECO Energy common equity, cash on hand and long-term debt at NMGI and NMGC.

The closing of the acquisition is subject to various customary closing conditions, including, among others (i) clearance under the Hart-Scott-Rodino Antitrust Improvements Act, (ii) receipt of all required regulatory approvals from the New Mexico Public Regulation Commission, and (iii) subject to certain materiality exceptions, the accuracy of the representations and warranties made by the parties to the SPA and compliance with their respective obligations under the SPA. The Hart-Scott-Rodino waiting period expired without any further request for information. The company filed for approval from the New Mexico Public Regulation Commission on July 9, 2013.

As previously reported, the company must obtain regulatory approvals from the NMPRC prior to consummating the pending acquisition of NMGC. On Jan. 10, 2014 a meeting was held with the joint applicants, hearing examiner, the NMPRC staff, and intervenors to establish an updated schedule. Based on this schedule, Staff and intervenor testimony is expected to occur on Feb. 28, with hearings to follow on March 24 – 28. The date for a final decision is yet to be determined. The company has indicated that the closing is likely to occur in the third quarter of 2014.

The SPA contains customary representations and warranties of the parties, and covenants to, among other things, cooperate on seeking necessary regulatory approvals and access to information. NMGI also agreed to conduct its business and the business of its subsidiary, NMGC, in the ordinary course until the acquisition is consummated and has agreed to cooperate with the company's efforts to obtain permanent financing. The acquisition is not subject to any financing condition and the company has entered into a credit agreement to provide bridge financing, as described in the section titled *TECO Finance Bridge Facility* below. The parties have agreed to indemnify each other for breaches of representations, warranties and covenants. Subject to certain exceptions, CES's aggregate liability with respect to such indemnification obligations is capped at $30 million (subject to a $9.25 million deductible), which will be placed initially into an escrow account at closing to be available to fund indemnification claims.

The SPA contains certain termination rights for CES and the company, including, among others, the right to terminate if the acquisition is not completed by May 25, 2014 (subject to up to a four month extension under certain circumstances related to obtaining required regulatory approvals which, if not obtained, would permit each party to terminate the SPA without paying a termination fee).

TECO Finance Bridge Facility

On June 24, 2013, the company and TECO Finance entered into a $1.075 billion Senior Unsecured Bridge Credit Agreement (Bridge Facility) among the company as guarantor, TECO Finance as borrower, Morgan Stanley as administrative agent, sole lead arranger and sole book runner, and the lenders named in the Bridge Facility. The Bridge Facility is sized to cover the $950 million purchase price and provide a $125 million credit facility for the operations of NMGC. Under the terms of the Bridge Facility, as of the closing of the NMGI acquisition, the Bridge Facility permits NMGC to be added to the Bridge Facility as a borrower.

Pursuant to the Bridge Facility, upon satisfaction of certain conditions precedent contained therein, the borrowers may borrow up to $1.075 billion. TECO Finance's obligations under the Bridge Facility are unconditionally guaranteed by the company. The Bridge Facility matures 364 days after the closing of the acquisition. Repaid amounts under the Bridge Facility may not be reborrowed.

The availability of funds under the Bridge Facility is subject to certain conditions including, among others, and in each case, subject to certain exceptions: (i) the absence of a "material adverse effect" on NMGC, consistent with the definitions in the SPA; (ii) the accuracy of the representations and warranties in the Bridge Facility; (iii) the consummation of the acquisition and the absence of certain changes or waivers to the SPA; (iv) the absence of defaults under the Bridge Facility and under certain other credit facilities of the company and its subsidiaries (Existing Credit Facilities); (v) the delivery of certain financial information pertaining to the company and its subsidiaries; (vi) the solvency of the company and its subsidiaries on a consolidated basis, and compliance, on a pro forma basis after giving effect to the acquisition, with all covenants in the Existing Credit Facilities of the company and its subsidiaries; (vii) the amendment of the TECO Credit Agreement to permit the acquisition (which amendment has been completed, as described in **Note 6**); (viii) the payment of certain transaction fees; and (ix) the delivery of customary closing documents.

The interest rate applicable to the Bridge Facility is, at the borrower's option, either a floating base rate or a floating Eurodollar rate, in each case, plus an applicable margin ranging from 0.25% to 2.0% depending on the company's credit rating, and subject to a 0.25% increase for each 90-day period that elapses after the closing of the acquisition.

The Bridge Facility contains certain covenants that, among other things, restrict (i) certain mergers, consolidations, liquidations and dissolutions of the company and certain subsidiaries, (ii) sales by the company and certain subsidiaries of all or a substantial part of its assets and, (iii) certain liens by of the company or certain subsidiaries on all or substantially all of such party's assets, in each case subject to exceptions substantially similar to those exceptions in the TECO Credit Facility. Under the Bridge Facility, the company must maintain, on a consolidated basis, a total debt to total capitalization ratio of no greater than 0.65 to 1.00 (except with respect to the four fiscal quarters commencing with the quarter in which the acquisition closes, during which it must maintain a total debt to total capitalization ratio of no greater than 0.70 to 1.00).

Additionally, the Bridge Facility also contains customary events of default, including, without limitation, payment defaults, breaches of representations and warranties, covenant defaults, cross-defaults to certain other material indebtedness, certain events of bankruptcy and insolvency, certain ERISA events, judgments in excess of specified amounts, certain impairments to the guarantee and changes in control.

TECO Energy Credit Agreement to be Assigned to and Assumed by NMGC

In connection with the pending Acquisition, on Dec. 17, 2013, TECO Energy entered into a $125 million bank credit facility, pursuant to which it is the initial party to the Credit Agreement (the NMGC Credit Agreement). TECO Energy has no rights or obligations to borrow under the NMGC Credit Agreement, which it has entered into solely with the intent of it being assigned to, and assumed by, NMGC upon the closing of the Acquisition. Pursuant to the terms of the NMGC Credit Agreement, upon such closing, TECO Energy will designate NMGC as the borrower under the NMGC Credit Agreement by delivering a Joinder and Release Agreement duly executed by TECO Energy and NMGC, whereupon and upon the satisfaction of the other conditions precedent set forth in the NMGC Credit Agreement, (i) NMGC shall automatically become the borrower for all purposes of the NMGC Credit Agreement and the other credit facility documents under the NMGC Credit Agreement, and (ii) TECO Energy shall cease to be a party to the NMGC Credit Agreement and shall have no further rights or obligations thereunder. The NMGC Credit Agreement (i) has a maturity date of Dec. 17, 2018 (subject to further extension with the consent of each lender); (ii) will allow NMGC to borrow funds at a rate equal to the one-month London interbank deposit rate plus a margin; (iii) as an alternative to the above interest rate, will allow NMGC to borrow funds at an interest rate equal to a margin plus the higher of JPMorgan Chase Bank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (iv) will allow NMGC to borrow funds on a same-day basis under a swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the borrower and the relevant swingline lender prior to the making of any such loans; (v) will allow NMGC to request the lenders to increase their commitments under the credit facility by up to $75 million in the aggregate; and (vi) includes a $40 million letter of credit facility.

23. Quarterly Data (unaudited)

Financial data by quarter is as follows:

(millions, except per share amounts)				
Quarter ended	*Dec. 31*	*Sept. 30*	*June 30*	*March 31*
2013				
Revenues	$ 688.4	$ 765.9	$ 735.9	$ 661.1
Income from operations	99.6	140.5	119.5	104.1
Net income from continuing operations	42.1	62.9	51.6	41.2
Net income attributable to TECO Energy	42.0	62.8	51.4	41.5
EPS - Basic				
From continuing operations	$ 0.20	$ 0.29	$ 0.24	$ 0.19
Attributable to TECO Energy	0.20	0.29	0.24	0.19
EPS - Diluted				
From continuing operations	$ 0.20	$ 0.29	$ 0.24	$ 0.19
Attributable to TECO Energy	0.20	0.29	0.24	0.19
Dividends paid per common share outstanding	$ 0.220	$ 0.220	$ 0.220	$ 0.220

Quarter ended	*Dec. 31*	*Sept. 30*	*June 30*	*March 31*
2012				
Revenues (1)	$ 688.4	$ 858.6	$ 752.5	$ 697.1
Income from operations (1)	109.5	183.1	149.1	114.8
Net income from continuing operations (1)	45.6	90.2	65.6	44.6
Net income attributable to TECO Energy	45.1	44.0	73.1	50.5
EPS - Basic				
From continuing operations (1)	$ 0.21	$ 0.42	$ 0.30	$ 0.21
Attributable to TECO Energy	0.21	0.20	0.34	0.24
EPS - Diluted				
From continuing operations (1)	$ 0.21	$ 0.42	$ 0.30	$ 0.20
Attributable to TECO Energy	0.21	0.20	0.34	0.23
Dividends paid per common share outstanding	$ 0.220	$ 0.220	$ 0.220	$ 0.220

(1) Amounts shown include reclassifications to reflect discontinued operations as discussed in **Note 19**.

24. Subsequent Events

Tampa Electric Company Accounts Receivable Facility

On Feb. 14, 2014, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 12 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A. as Program Agent. The amendment (i) extends the maturity date to Feb. 13, 2015, (ii) provides that TRC will pay program and liquidity fees, which will total 70.0 basis points, (iii) continues to provide that the interest rates on the borrowings will be based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to, at TEC's option, either Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the LIBOR (if available) plus a margin, (iv) confirms that CAFCO, LLC will be the Committed Lender and Conduit Lender and (v) makes other technical changes.

TAMPA ELECTRIC COMPANY
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

All other financial statement schedules have been omitted since they are not required, are inapplicable or the required information is presented in the financial statements or notes thereto.

Report of Independent Registered Certified Public Accounting Firm

To the Board of Directors and Shareholder of Tampa Electric Company:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Tampa Electric Company and its subsidiaries at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Tampa, Florida

February 28, 2014

TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets

Assets *(millions)*	*Dec. 31, 2013*	*Dec. 31, 2012*
Property, plant and equipment		
Utility plant in service		
Electric	$ 6,934.0	$ 6,654.5
Gas	1,249.5	1,171.9
Construction work in progress	385.3	335.0
Utility plant in service, at original costs	8,568.8	8,161.4
Accumulated depreciation	(2,562.6)	(2,373.6)
	6,006.2	5,787.8
Other property	8.3	7.3
Total property, plant and equipment, net	6,014.5	5,795.1
Current assets		
Cash and cash equivalents	9.8	45.2
Receivables, less allowance for uncollectibles of $2.0 and $1.5 at Dec. 31, 2013 and 2012, respectively	227.6	213.8
Inventories, at average cost		
Fuel	93.7	89.1
Materials and supplies	76.8	72.4
Regulatory assets	34.3	70.3
Derivative assets	9.5	0.0
Taxes receivable	54.9	22.1
Deferred income taxes	29.4	20.0
Prepayments and other current assets	12.5	11.5
Total current assets	548.5	544.4
Deferred debits		
Unamortized debt expense	14.8	16.1
Regulatory assets	293.1	382.6
Derivative assets	0.3	0.2
Other	4.6	6.2
Total deferred debits	312.8	405.1
Total assets	$ 6,875.8	$ 6,744.6

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

TAMPA ELECTRIC COMPANY
Consolidated Balance Sheets - continued

Liabilities and Capital *(millions)*	*Dec. 31, 2013*	*Dec. 31, 2012*
Capitalization		
Common stock	$ 2,030.4	$ 1,970.4
Accumulated other comprehensive loss	(7.8)	(8.7)
Retained earnings	308.1	304.6
Total capital	2,330.7	2,266.3
Long-term debt, less amount due within one year	1,797.5	1,932.6
Total capital	4,128.2	4,198.9
Current liabilities		
Long-term debt due within one year	83.3	0.0
Notes payable	84.0	0.0
Accounts payable	226.0	188.6
Customer deposits	164.5	163.0
Regulatory liabilities	85.8	105.6
Derivative liabilities	0.0	14.1
Interest accrued	16.4	17.3
Taxes accrued	12.2	13.7
Other	12.0	11.8
Total current liabilities	684.2	514.1
Deferred credits		
Deferred income taxes	1,114.3	980.9
Investment tax credits	9.4	9.7
Derivative liabilities	0.2	0.2
Regulatory liabilities	631.4	631.4
Other	308.1	409.4
Total deferred credits	2,063.4	2,031.6
Commitments and Contingencies (see **Note 10**)		
Total liabilities and capital	$ 6,875.8	$ 6,744.6

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Income and Comprehensive Income

(millions) *For the years ended Dec. 31,*	*2013*	*2012*	*2011*
Revenues			
Electric (includes franchise fees and gross receipts taxes of $88.0 in 2013, $91.1 in 2012 and $85.6 in 2011)	$ 1,950.1	$ 1,981.0	$ 2,020.1
Gas (includes franchise fees and gross receipts taxes of $20.5 in 2013, $20.4 in 2012 and $23.7 in 2011)	392.7	397.0	450.5
Total revenues	2,342.8	2,378.0	2,470.6
Expenses			
Regulated operations & maintenance			
Fuel	680.2	694.7	731.4
Purchased power	64.7	105.3	125.9
Cost of natural gas sold	142.6	155.8	210.4
Other	523.6	462.0	436.4
Depreciation and amortization	290.3	288.2	270.5
Taxes, other than income	183.1	184.0	179.7
Total expenses	1,884.5	1,890.0	1,954.3
Income from operations	458.3	488.0	516.3
Other income			
Allowance for other funds used during construction	6.3	2.6	1.0
Other income, net	5.1	4.1	2.9
Total other income	11.4	6.7	3.9
Interest charges			
Interest on long-term debt	105.0	119.6	128.6
Other interest	3.9	7.7	11.5
Allowance for borrowed funds used during construction	(3.6)	(1.5)	(0.6)
Total interest charges	105.3	125.8	139.5
Income before provision for income taxes	364.4	368.9	380.7
Provision for income taxes	138.8	141.7	145.4
Net income	225.6	227.2	235.3
Other comprehensive income, net of tax			
Net unrealized (loss) gain on cash flow hedges	0.9	(4.1)	0.7
Total other comprehensive (loss) income, net of tax	0.9	(4.1)	0.7
Comprehensive income	$ 226.5	$ 223.1	$ 236.0

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Cash Flows

(millions) *For the years ended Dec. 31,*	*2013*	*2012*	*2011*
Cash flows from operating activities			
Net income	$ 225.6	$ 227.2	$ 235.3
Adjustments to reconcile net income to net cash from operating activities:			
Depreciation and amortization	290.3	288.2	270.5
Deferred income taxes	118.4	155.9	173.6
Investment tax credits, net	(0.3)	(0.3)	(0.4)
Allowance for other funds used during construction	(6.3)	(2.6)	(1.0)
Deferred recovery clauses	(6.2)	(8.9)	(9.0)
Receivables, less allowance for uncollectibles	(13.8)	1.6	47.8
Inventories	(9.0)	4.1	12.6
Prepayments	(1.0)	(1.0)	(0.5)
Taxes accrued	(34.3)	(5.7)	7.9
Interest accrued	(0.9)	(8.3)	1.0
Accounts payable	34.8	12.4	(42.2)
Gain on sale of assets, pretax	0.0	(0.2)	(0.3)
Other	(1.8)	5.2	29.4
Cash flows from operating activities	595.5	667.6	724.7
Cash flows from investing activities			
Capital expenditures	(507.6)	(459.0)	(386.8)
Allowance for other funds used during construction	6.3	2.6	1.0
Net proceeds from sale of assets	0.1	0.3	2.8
Cash flows used in investing activities	(501.2)	(456.1)	(383.0)
Cash flows from financing activities			
Common stock	60.0	118.0	0.0
Proceeds from long-term debt issuance	0.0	538.1	0.0
Repayment of long-term debt/Purchase in lieu of redemption	(51.6)	(608.0)	(78.8)
Net increase (decrease) in short-term debt	84.0	0.0	(12.0)
Dividends	(222.1)	(228.3)	(240.7)
Cash flows used in financing activities	(129.7)	(180.2)	(331.5)
Net increase (decrease) in cash and cash equivalents	(35.4)	31.3	10.2
Cash and cash equivalents at beginning of the year	45.2	13.9	3.7
Cash and cash equivalents at end of the year	$ 9.8	$ 45.2	$ 13.9

Supplemental disclosure of cash flow information			
Cash paid (received) during the year for:			
Interest	$ 102.4	$ 128.1	$ 129.0
Income taxes	$ 56.4	$ (9.7)	$ (31.1)

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Retained Earnings

(millions) *For the years ended Dec. 31,*	*2013*	*2012*	*2011*
Balance, beginning of year	$304.6	$305.7	$311.1
Add: Net income	225.6	227.2	235.3
	530.2	532.9	546.4
Deduct: Cash dividends on capital stock - common	222.1	228.3	240.7
Balance, end of year	$308.1	$304.6	$305.7

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Capitalization

	Current Redemption	Capital Stock Outstanding *Dec. 31,*		Cash Dividends Paid (1)	
(millions, except share amounts)	Price	Shares	Amount	Per Share	Amount
Common stock - without par value					
25 million shares authorized					
2013 (3)(4)	N/A	10	$ 2,030.4	*(2)*	$ 222.1
2012 (3)(4)	N/A	10	$ 1,970.4	*(2)*	$ 228.3

Preferred stock – $100 par value
1.5 million shares authorized, none outstanding.

Preferred stock – no par
2.5 million shares authorized, none outstanding.

Preference stock – no par
2.5 million shares authorized, none outstanding.

(1) Quarterly dividends paid on Feb. 28, May 28, Aug. 28 and Nov. 27 during 2013.
Quarterly dividends paid on Feb. 28, May 29, Aug. 28 and Nov. 28 during 2012.
(2) Not meaningful.
(3) No issue expense.
(4) TECO Energy made equity contributions to TEC of $60.0 million in 2013 and $118.0 million in 2012.

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Capitalization – continued

At Dec. 31, 2013 and 2012, TEC had the following long-term debt outstanding:

Long-Term Debt *(millions) Dec. 31,*		*Due*	*2013*	*2012*
Tampa Electric	Installment contracts payable (1):			
	5.65% Refunding bonds (effective rate of 5.9%)	2018	$54.2	$54.2
	Variable rate bonds repurchased in 2008 (2)	2020	0.0	0.0
	5.15% Refunding bonds repurchased in 2013 (effective rate of 5.4% for 2012) (3)	2025	0.0	51.6
	1.5% Term rate bonds repurchased in 2011 (4)	2030	0.0	0.0
	5.0% Refunding bonds repurchased in 2012 (5)	2034	0.0	0.0
	Notes (6): 6.25% (effective rate of 6.3%) (7)	2014-2016	250.0	250.0
	6.1% (effective rate of 6.0%)	2018	200.0	200.0
	5.4% (effective rate of 5.4%)	2021	231.7	231.7
	2.6% (effective rate of 2.7%)	2022	225.0	225.0
	6.55% (effective rate of 6.6%)	2036	250.0	250.0
	6.15% (effective rate of 6.2%)	2037	190.0	190.0
	4.1% (effective rate of 4.2%)	2042	250.0	250.0
Total long-term debt of Tampa Electric			1,650.9	1,702.5
PGS	Notes (6): 6.1% (effective rate of 7.0%)	2018	50.0	50.0
	5.4% (effective rate of 5.4%)	2021	46.7	46.7
	2.6% (effective rate of 2.7%)	2022	25.0	25.0
	6.15% (effective rate of 6.2%)	2037	60.0	60.0
	4.1% (effective rate of 4.2%)	2042	50.0	50.0
Total long-term debt of PGS			231.7	231.7
Total long-term debt of Tampa Electric Company			1,882.6	1,934.2
Unamortized debt discount, net			(1.8)	(1.6)
Total carrying amount of long-term debt			1,880.8	1,932.6
Less amount due within one year			83.3	0.0
Total long-term debt			$1,797.5	$1,932.6

(1) Tax-exempt securities.
(2) In March 2008 these bonds, which were in auction rate mode, were purchased in lieu of redemption by TEC. These held variable rate bonds have a par amount of $20.0 million due in 2020.
(3) In September 2013 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $51.6 million due in 2025.
(4) In March 2011 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $75.0 million due in 2030.
(5) In March 2012 these bonds, which were in term rate mode, were purchased in lieu of redemption by TEC. These held term rate bonds have a par amount of $86.0 million due in 2034.
(6) These securities are subject to redemption in whole or in part, at any time, at the option of the company.
(7) These long-term debt agreements contain various restrictive covenants.

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

TAMPA ELECTRIC COMPANY
Consolidated Statements of Capitalization - continued

At Dec. 31, 2013, total long-term debt had a carrying amount of $1,880.8 million and an estimated fair market value of $2,042.0 million. At Dec. 31, 2012, total long-term debt had a carrying amount of $1,932.6 million and an estimated fair market value of $2,271.9 million. TEC uses the market approach in determining fair value. The majority of the outstanding debt is valued using real-time financial market data obtained from Bloomberg Professional Service. The remaining securities are valued using prices obtained from the Municipal Securities Rulemaking Board and by applying estimated credit spreads obtained from a third party to the par value of the security. All debt securities are Level 2 instruments.

A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture, and Tampa Electric could cause the lien associated with this indenture to be released at any time. Gross maturities and annual sinking fund requirements of long-term debt for the years 2014 through 2018 and thereafter are as follows:

Long-Term Debt Maturities

As of Dec. 31, 2013 (millions)	*2014*	*2015*	*2016*	*2017*	*2018*	*Thereafter*	*Total Long-Term Debt*
Tampa Electric	$83.3	$83.3	$83.4	$0.0	$254.2	$1,146.7	$1,650.9
PGS	0.0	0.0	0.0	0.0	50.0	181.7	231.7
Total long-term debt maturities	$83.3	$83.3	$83.4	$0.0	$304.2	$1,328.4	$1,882.6

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

TAMPA ELECTRIC COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Significant Accounting Policies

The significant accounting policies are as follows:

Basis of Accounting

TEC maintains its accounts in accordance with recognized policies prescribed or permitted by the FPSC and the FERC. These policies conform with GAAP in all material respects.

The impact of the accounting guidance for the effects of certain types of regulation has been minimal in the company's experience, but when cost recovery is ordered over a period longer than a fiscal year, costs are recognized in the period that the regulatory agency recognizes them in accordance with this guidance.

TEC's retail and wholesale businesses are regulated by the FPSC and related FERC, respectively. Prices allowed by both agencies are generally based on recovery of prudent costs incurred plus a reasonable return on invested capital.

Principles of Consolidation

TEC is a wholly-owned subsidiary of TECO Energy, Inc., and is comprised of the Electric division, generally referred to as Tampa Electric, and the Natural Gas division, PGS. All significant intercompany balances and intercompany transactions have been eliminated in consolidation. The use of estimates is inherent in the preparation of financial statements in accordance with GAAP. Actual results could differ from these estimates.

For entities that are determined to meet the definition of a VIE, TEC obtains information, where possible, to determine if it is the primary beneficiary of the VIE. If TEC 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 TEC 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 TEC consolidating entities in which it has less than a 50% equity investment and deconsolidating entities in which it has a majority equity interest (see **Note 15**).

Planned Major Maintenance

Tampa Electric and PGS expense major maintenance costs as incurred. Concurrent with a planned major maintenance outage, the cost of adding or replacing retirement units-of-property is capitalized in conformity with FPSC and FERC regulations.

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.

Depreciation

Tampa Electric and PGS compute depreciation and amortization for electric generation, electric transmission and distribution, gas distribution and general plant facilities using the following methods:

- the group remaining life method, approved by the FPSC, is applied to the average investment, adjusted for anticipated costs of removal less salvage, in functional classes of depreciable property;
- the amortizable life method, approved by the FPSC, is applied to the net book value to date over the remaining life of those assets not classified as depreciable property above.

The provision for total regulated utility plant in service, expressed as a percentage of the original cost of depreciable property, was 3.7% for 2013 and 3.8% for 2012 and 3.6% for 2011. Construction work in progress is not depreciated until the asset is completed or placed in service. Total depreciation expense for the years ended Dec. 31, 2013, 2012 and 2011 was $284.2 million, $275.1 million and $263.7 million, respectively.

On Sept. 11, 2013, the FPSC unanimously voted to approve a stipulation and settlement agreement between TEC and all of the intervenors in its Tampa Electric division base rate proceeding. As a result, Tampa Electric will begin using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013.

Cash Flows Related to Derivatives and Hedging Activities

TEC classifies cash inflows and outflows related to derivative and hedging instruments in the appropriate cash flow sections associated with the item being hedged. For natural gas, the cash inflows and outflows are included in the operating section of the Consolidated Statements of Cash Flows.

Allowance for Funds Used During Construction

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 FPSC approved rate used to calculate AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. The rate was 8.16% for May 2009 through December 2013. Total AFUDC for the years ended Dec. 31, 2013, 2012 and 2011 was $9.9 million, $4.1 million and $1.6 million, respectively.

Deferred Income Taxes

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

Investment Tax Credits

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

Inventory

TEC values materials, supplies and fossil fuel inventory (coal, oil and natural gas) using a weighted-average cost method. These materials, supplies and fuel inventories are carried at the lower of weighted-average cost or market, unless evidence indicates that the weighted-average cost (even if in excess of market) will be recovered with a normal profit upon sale in the ordinary course of business.

Revenue Recognition

TEC recognizes revenues consistent with accounting standards for revenue recognition. Except as discussed below, TEC recognizes 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.

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 the FERC. See **Note 3** for a discussion of significant regulatory matters and the applicability of the accounting guidance for certain types of regulation to the company.

Revenues and Cost Recovery

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- 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 regulatory liabilities, and under-recoveries of costs are recorded as regulatory assets.

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, 2013 and 2012, unbilled revenues of $46.7 million and $49.0 million, respectively, are included in the "Receivables" line item on TEC's Consolidated Balance Sheets.

Tampa Electric purchases power on a regular basis primarily to meet the needs of its retail customers. Tampa Electric purchased power from non-TECO Energy affiliates at a cost of $64.7 million, $105.3 million and $125.9 million, for the years ended Dec. 31, 2013, 2012 and 2011, 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

TEC is allowed to recover certain costs on a dollar-per-dollar basis 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. 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". These amounts totaled $108.5 million, $111.5 million and $109.3 million for the years ended Dec. 31, 2013, 2012 and 2011, respectively. Excise taxes paid by the regulated utilities are not material and are expensed as incurred.

Reclassifications

Certain reclassifications were made to prior year amounts to conform to current period presentation. None of the reclassifications affected TEC's net income in any period.

2. New Accounting Pronouncements

Comprehensive Income

In February 2013, the FASB issued guidance requiring improved disclosures of significant reclassifications out of AOCI and their corresponding effect on net income. The guidance is effective for interim and annual reporting periods beginning on or after Dec. 15, 2012. TEC has adopted this guidance as required. It has no effect on TEC's results of operations, financial position or cash flows.

Offsetting Assets and Liabilities

In December 2011, the FASB issued guidance enhancing disclosures of financial instruments and derivative instruments that are offset in the statement of financial position or subject to enforceable master netting agreements. The guidance is effective for interim and annual reporting periods beginning on or after Jan. 1, 2013. TEC has adopted this guidance as required. It had no effect on TEC's results of operations, financial position or cash flows.

3. Regulatory

Tampa Electric's and PGS's retail businesses are regulated by the FPSC. Tampa Electric is also subject to regulation by the FERC under PUHCA 2005. However, pursuant to a waiver granted in accordance with the FERC's regulations, TECO Energy is not subject to certain accounting, record-keeping and reporting requirements prescribed by the FERC's regulations under PUHCA 2005. The operations of PGS are regulated by the FPSC separately from the operations of Tampa Electric. The FPSC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the FPSC sets rates at a level that allows utilities such as Tampa Electric and PGS to collect total revenues (revenue requirements) equal to their cost of providing service, plus a reasonable return on invested capital.

Base Rates-Tampa Electric

Tampa Electric's results for the first ten months of 2013, and all of 2012 and 2011, reflect base rates established in March 2009, when the FPSC awarded $104 million higher revenue requirements effective in May 2009 that authorized an ROE midpoint of 11.25%, 54.0% equity in the capital structure and 2009 13-month average rate base of $3.4 billion. In a series of subsequent decisions in 2009 and 2010, related to a calculation error and a step increase for CTs and rail unloading facilities that entered service before the end of 2009, base rates increased an additional $33.5 million.

On Feb. 4, 2013, Tampa Electric delivered a letter to the FPSC notifying it of its intent to file a request for an increase in its retail base rates and service charges. On April 5, 2013, Tampa Electric filed a petition with the FPSC requesting, among other things, a permanent increase in rates and service charges sufficient to generate additional annual revenues of approximately $134.8 million, to be effective on or after Jan. 1, 2014. The request provided for a return on equity range of 10.25% to 12.25% with a midpoint of 11.25%. The petition also requested certain changes to existing rate schedules, as well as the adoption of new rate designs.

On Sept. 6, 2013, TEC and all of the intervenors in its Tampa Electric division base rate proceeding filed with the FPSC a joint motion for the FPSC to approve a stipulation and settlement agreement, which would resolve all matters in Tampa Electric's pending base rate proceeding.

This agreement provided for the following revenue increases: $57.5 million effective Nov. 1, 2013, an additional $7.5 million effective Nov. 1, 2014, an additional $5.0 million effective Nov. 1, 2015, and an additional $110.0 million effective Jan. 1, 2017 or the date that the expansion of TEC's Polk Power Station goes into service, whichever is later. The agreement provides that Tampa Electric's allowed regulatory ROE would be a mid-point of 10.25% with a range of plus or minus 1%, with a potential increase to 10.50% if U.S. Treasury bond yields exceed a specified threshold. The agreement provides that Tampa Electric cannot file for additional rate increases until 2017 (to be effective in 2018), unless its earned ROE were to fall below 9.25% (or 9.5% if the allowed ROE is increased as described above) before that time. If its earned ROE were to rise above 11.25% (or 11.5% if the allowed ROE is increased as described above) any party to the agreement other than TEC could seek a review of Tampa Electric's base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital and Tampa Electric will begin using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013.

On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement between TEC and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved Tampa Electric's base rate proceeding.

Tampa Electric is also subject to regulation by the FERC in various respects, including wholesale power sales, certain wholesale power purchases, transmission and ancillary services and accounting practices.

Storm Damage Cost Recovery

Prior to the above mentioned stipulation and settlement agreement, Tampa Electric was accruing $8.0 million annually to a FERC-authorized and FPSC-approved self-insured storm damage reserve. This reserve was created after Florida's IOUs were unable to obtain transmission and distribution insurance coverage due to destructive acts of nature. Tampa Electric's storm reserve was $56.1 million and $50.4 million as of Dec. 31, 2013 and 2012, respectively. Effective Nov. 1, 2013, Tampa Electric ceased accruing for this storm damage reserve. However, in the event of a named storm that results in damage to its system, Tampa Electric can petition the FPSC to seek recovery of those costs over a 12-month period or longer as determined by the FPSC, as well as replenish its reserve to the level as of Oct. 31, 2013.

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.

Tampa Electric and PGS apply the accounting standards for regulated operations. 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 the deferral of costs as regulatory assets to the period in which the regulatory agency recognizes them, when cost recovery is ordered over a period longer than a fiscal year.

Details of the regulatory assets and liabilities as of Dec. 31, 2013 and 2012 are presented in the following table:

Regulatory Assets and Liabilities

(millions)	*Dec. 31, 2013*	*Dec. 31, 2012*
Regulatory assets:		
Regulatory tax asset [1]	$ 67.4	$ 67.2
Other:		
Cost-recovery clauses	6.1	42.9
Postretirement benefit asset	182.7	276.1
Deferred bond refinancing costs [2]	8.0	9.2
Environmental remediation	51.4	46.9
Competitive rate adjustment	4.1	4.1
Other	7.7	6.5
Total other regulatory assets	260.0	385.7
Total regulatory assets	327.4	452.9
Less: Current portion	34.3	70.3
Long-term regulatory assets	$ 293.1	$ 382.6
Regulatory liabilities:		
Regulatory tax liability [1]	$ 9.8	$ 14.6
Other:		
Cost-recovery clauses	54.5	73.9
Transmission and delivery storm reserve	56.1	50.4
Deferred gain on property sales [3]	2.0	3.4
Provision for stipulation and other	0.8	1.0
Accumulated reserve - cost of removal	594.0	593.7
Total other regulatory liabilities	707.4	722.4
Total regulatory liabilities	717.2	737.0
Less: Current portion	85.8	105.6
Long-term regulatory liabilities	$ 631.4	$ 631.4

(1) Primarily related to plant life and derivative positions.

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

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

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

Regulatory assets

(millions)		*Dec. 31, 2013*		*Dec. 31, 2012*
Clause recoverable [1]	$	10.2	$	47.0
Components of rate base [2]		185.6		279.1
Regulatory tax assets [3]		67.4		67.2
Capital structure and other [3]		64.2		59.6
Total	$	327.4	$	452.9

(1) To be recovered through recovery mechanisms 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 a 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 Taxes

TEC is included in the filing of a consolidated federal income tax return with TECO Energy and its affiliates. TEC’s income tax expense is based upon a separate return computation. For the three years presented, TEC’s effective tax rate differs from the statutory rate principally due to state income taxes, domestic production deduction and AFUDC equity benefit. The decrease in the 2013 effective tax rate compared to 2012 is principally due to equity portion of AFUDC.

Income tax expense consists of the following components:

Income Tax Expense (Benefit)

(millions) *For the year ending Dec. 31,*		*2013*		*2012*		*2011*
Current income taxes						
Federal	$	19.4	$	(19.5)	$	(30.7)
State		1.3		5.6		2.9
Deferred income taxes						
Federal		99.8		141.2		155.6
State		18.6		14.7		18.0
Amortization of investment tax credits		(0.3)		(0.3)		(0.4)
Total income tax expense	$	138.8	$	141.7	$	145.4

The total income tax provisions differ from amounts computed by applying the federal statutory tax rate to income before income taxes as follows:

Effective Income Tax Rate

(millions) *For the years ended Dec. 31,*		*2013*		*2012*		*2011*
Income tax expense at the federal statutory rate of 35%	$	127.5	$	129.1	$	133.2
Increase (decrease) due to						
State income tax, net of federal income tax		13.0		13.2		13.6
Equity portion of AFUDC		(2.2)		(0.9)		(0.4)
Domestic production deduction		(0.6)		(0.4)		(1.5)
Other		1.1		0.7		0.5
Total income tax expense on consolidated statements of income	$	138.8	$	141.7	$	145.4
Income tax expense as a percent of income from continuing operations, before income taxes		38.1%		38.4%		38.2%

Deferred taxes result from temporary differences in the recognition of certain liabilities or assets for tax and financial reporting purposes. The principal components of TEC's deferred tax assets and liabilities recognized in the balance sheet are as follows:

Deferred Income Taxes

(millions) *As of Dec. 31,*	*2013*	*2012*
Deferred tax liabilities [1]		
Property related	$ 1,166.4	$ 1,016.2
Deferred fuel	1.6	11.3
Pension and postretirement benefits	70.5	106.6
Pension	43.2	36.7
Other	0.0	22.2
Total deferred tax liabilities	1,281.7	1,193.0
Deferred tax assets [1]		
Medical benefits	50.9	49.0
Insurance reserves	29.1	31.1
Investment tax credits	5.3	5.5
Hedging activities	4.9	5.5
Pension and postretirement benefits	70.5	106.6
Unbilled revenue	12.1	14.8
Capitalized energy conservation assistance costs	19.6	19.6
Other	4.4	0.0
Total deferred tax assets	196.8	232.1
Total deferred tax liability, net	1,084.9	960.9
Less: Current portion of deferred tax asset	(29.4)	(20.0)
Long-term portion of deferred tax liability, net	$ 1,114.3	$ 980.9

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

TEC accounts for uncertain tax positions as required by FASB accounting guidance. This guidance addresses the determination of whether tax benefits claimed or expected to be claimed on a tax return should be recorded in the financial statements. Under the guidance, TEC may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities based on the technical merits of the position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. The guidance also provides standards on derecognition, classification, interest and penalties on income taxes, accounting in interim periods and requires increased disclosures.

As of Dec. 31, 2013 and 2012, TEC did not have a liability for unrecognized tax benefits. Based on current information, TEC does not anticipate that this will change materially in 2014. As of Dec. 31, 2013, TEC does not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

The IRS concluded its examination of federal income tax returns for the year 2012 in January 2014. The U.S. federal statute of limitations remains open for the year 2010 and onward. The federal income tax return for calendar year 2013 is part of the IRS's Compliance Assurance Program. As a result, the IRS audit of such return is expected to be completed in 2014. Florida's statute of limitations is three years from the filing of an income tax return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by Florida's tax authorities include 2010 and onward. TEC does not expect the settlement of audit examinations to significantly change the total amount of unrecognized tax benefits within the next 12 months.

5. Employee Postretirement Benefits

Pension Benefits

TEC is a participant in the comprehensive retirement plans of TECO Energy, including a non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on the employees' age, years of service and final average earnings. Where appropriate and reasonably determinable, the portion of expenses, income, gains or losses allocable to TEC are presented. Otherwise, such amounts presented reflect the amount allocable to all participants of the TECO Energy retirement plans.

The Pension Protection Act became effective Jan. 1, 2008 and requires companies to, among other things, maintain certain defined minimum funding thresholds (or face plan benefit restrictions), pay higher premiums to the PBGC if they sponsor defined benefit plans, amend plan documents and provide additional plan disclosures in regulatory filings and to plan participants.

WRERA was signed into law on Dec. 23, 2008. WRERA grants plan sponsors relief from certain funding requirements and benefits restrictions, and also provides some technical corrections to the Pension Protection Act. There are two primary provisions that impact funding results for TECO Energy. First, for plans funded less than 100%, required shortfall contributions will be based on a percentage of the funding target until 2012, rather than the funding target of 100%. Second, one of the technical corrections, referred to as asset smoothing, allows the use of asset averaging subject to certain limitations in the determination of funding requirements. TECO Energy utilizes asset smoothing in determining funding requirements.

In July 2012, the President signed into law the MAP-21. MAP-21 provides funding relief for pension plan sponsors by stabilizing discount rates used in calculating the required minimum pension contributions and increasing PBGC premium rates to be paid by plan sponsors. TECO Energy expects the required minimum pension contributions to be lower than the levels previously projected; however, TECO Energy plans on funding at levels above the required minimum pension contributions under MAP-21.

The qualified pension plan's actuarial value of assets, including credit balance, was 96.7% of the Pension Protection Act funded target as of Jan. 1, 2013 and is estimated at 98.2% of the Pension Protection Act funded target as of Jan. 1, 2014.

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

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. Where appropriate and reasonably determinable, the portion of expenses, income, gains or losses allocable to TEC are presented. Otherwise, such amounts presented reflect the amount allocable to all participants of the TECO Energy postretirement health care and life insurance plans. Postretirement benefit levels are substantially unrelated to salary. TECO Energy reserves the right to terminate or modify the plans in whole or in part at any time.

MMA 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.

The FASB issued accounting guidance and disclosure requirements related to the MMA. The guidance 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.

In March 2010, the Patient Protection and Affordable Care Act and a companion bill, the Health Care and Education Reconciliation Act, collectively referred to as the Health Care Reform Acts, were signed into law. Among other things, both acts reduced the tax benefits available to an employer that receives the Medicare Part D subsidy, resulting in a write-off of any associated deferred tax asset. As a result, TEC reduced its deferred tax asset and recorded a corresponding regulatory asset in 2010. This amount was trued up in 2012. TEC is amortizing the regulatory asset over the remaining average service life of 12 years. Additionally, the Health Care Reform Acts contain other provisions that may impact TECO Energy's obligation for retiree medical benefits. In particular, the Health Care Reform Acts include a provision that imposes an excise tax on certain high-cost plans beginning in 2018, whereby premiums paid over a prescribed threshold will be taxed at a 40% rate. TECO Energy does not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase its PBO. TECO Energy will continue to monitor and assess the impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, on its future results of operations, cash flows or financial position.

Effective Jan. 1, 2013, the company decided to implement an EGWP for its post-65 retiree prescription drug plan. The EGWP is a private Medicare Part D plan designed to provide benefits that are at least equivalent to Medicare Part D. The EGWP reduces net periodic benefit cost by taking advantage of rebate and discount enhancements provided under the Health Care Reform Acts. Prior to this, the company received subsidy payments under Medicare Part D for its post-65 retiree prescription drug plan.

Obligations and Funded Status

TEC recognizes in its statement of financial position the over-funded or under-funded status of its postretirement benefit plans. This status is measured as the difference between the fair value of plan assets and the PBO in the case of its defined benefit plan, or the APBO in the case of its other postretirement benefit plan. Changes in the funded status are reflected, net of estimated tax benefits, in benefit liabilities and regulatory assets. The results of operations are not impacted. Below is the detail of the change in benefit obligations, change in plan assets, unfunded liability and amounts recognized in TECO Energy's Consolidated Balance Sheets for 2013 and 2012.

TECO Energy Obligations and Funded Status *(millions)*	Pension Benefits *2013*	 *2012*	Other Benefits *2013*	 *2012*
Change in benefit obligation				
Net benefit obligation at beginning of year	$715.0	$646.4	$230.3	$216.5
Service cost	18.2	17.0	2.5	2.4
Interest cost	28.9	30.1	9.3	10.1
Plan participants' contributions	0.0	0.0	2.9	3.7
Plan amendments	0.0	0.0	0.0	(5.2)
Actuarial loss (gain)	(50.4)	54.7	(22.1)	16.3
Gross benefits paid	(43.1)	(33.2)	(15.0)	(14.5)
Settlements	(2.6)	0.0	0.0	0.0
Federal subsidy on benefits paid	n/a	n/a	0.2	1.0
Net benefit obligation at end of year	$666.0	$715.0	$208.1	$230.3
Change in plan assets				
Fair value of plan assets at beginning of year	$529.1	$467.6	$0.0	$0.0
Actual return on plan assets	63.7	57.9	0.0	0.0
Employer contributions	45.9	36.8	11.9	9.8
Plan participants' contributions	0.0	0.0	2.9	3.7
Settlements	(2.6)	0.0	0.0	0.0
Gross benefits paid	(43.1)	(33.2)	(14.8)	(13.5)
Fair value of plan assets at end of year	$593.0	$529.1	$0.0	$0.0
Funded status				
Fair value of plan assets (1)	$593.0	$529.1	$0.0	$0.0
Less: Benefit obligation (PBO/APBO)	666.0	715.0	208.1	230.3
Funded status at end of year	(73.0)	(185.9)	(208.1)	(230.3)
Unrecognized net actuarial loss	173.1	270.3	19.7	42.7
Unrecognized prior service (benefit) cost	(0.4)	(0.7)	(0.7)	(1.0)
Unrecognized net transition obligation	0.0	0.0	0.0	0.0
Net amount required to be recognized at end of year	$99.7	$83.7	($189.1)	($188.6)
Amounts recognized in balance sheet				
Regulatory assets	$139.6	$216.5	$43.2	$59.6
Accrued benefit costs and other current liabilities	(3.3)	(5.3)	(13.3)	(13.1)
Deferred credits and other liabilities	(69.7)	(180.6)	(194.8)	(217.2)
Accumulated other comprehensive loss (income), pretax	33.1	53.1	(24.2)	(17.9)
Net amount recognized at end of year	$99.7	$83.7	($189.1)	($188.6)

(1) The MRV of plan assets is used as the basis for calculating the EROA component of periodic pension expense. MRV reflects the fair value of plan assets adjusted for experience gains and losses (i.e. the differences between actual investment returns and expected returns) spread over five years.

Tampa Electric Company Amounts recognized in balance sheet *(millions)*	Pension Benefits *2013*	 *2012*	Other Benefits *2013*	 *2012*
Regulatory assets	$ 139.6	$ 216.5	$ 43.2	$ 59.6
Accrued benefit costs and other current liabilities	(0.9)	(0.9)	(10.8)	(10.6)
Deferred credits and other liabilities	(50.1)	(139.8)	(158.3)	(174.2)
	$ 88.6	$ 75.8	$ (125.9)	$ (125.2)

The accumulated benefit obligation for TECO Energy Consolidated defined benefit pension plans was $624.1 million at Dec. 31, 2013 and $664.7 million at Dec. 31, 2012. The projected benefit obligation for the other postretirement benefits plan was $208.1 million at Dec. 31, 2013 and $230.3 million at Dec. 31, 2012.

Assumptions used to determine benefit obligations at Dec. 31:

	Pension Benefits		Other Benefits	
	2013	*2012*	*2013*	*2012*
Discount rate	5.118%	4.196%	5.096%	4.180%
Rate of compensation increase-weighted average	3.73%	3.76%	3.71%	3.74%
Healthcare cost trend rate				
Immediate rate	n/a	n/a	7.25%	7.50%
Ultimate rate	n/a	n/a	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	2025	2025

A one-percentage-point change in assumed health care cost trend rates would have the following effect on TEC's benefit obligation:

(millions)	1% Increase	1 % Decrease
Effect on postretirement benefit obligation	$ 5.6	$ (5.0)

The discount rate assumption used to determine the Dec. 31, 2013 benefit obligation was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

Components of TECO Energy Consolidated Net Periodic Benefit Cost

	Pension Benefits			Other Benefits		
(millions)	*2013*	*2012*	*2011*	*2013*	*2012*	*2011*
Service cost	$ 18.2	$ 17.0	$ 16.0	$ 2.4	$ 2.4	$ 2.1
Interest cost	28.9	30.1	30.9	9.3	10.1	11.1
Expected return on plan assets	(38.4)	(37.1)	(38.4)	0.0	0.0	0.0
Amortization of:						
Actuarial loss	20.5	15.3	11.3	1.0	0.1	0.1
Prior service (benefit) cost	(0.4)	(0.4)	(0.4)	(0.3)	0.8	0.8
Transition obligation	0.0	0.0	0.0	0.0	1.8	2.3
Settlement loss	1.0	0.0	0.9	0.0	0.0	0.0
Net periodic benefit cost	$ 29.8	$ 24.9	$ 20.3	$ 12.4	$ 15.2	$ 16.4

Other Changes in Plan Assets and Benefit Obligations Recognized in OCI and Regulatory Assets

(millions)	*2013*	*2012*	*2011*	*2013*	*2012*	*2011*
Prior service cost	$0.0	$0.0	$0.0	$0.0	$ (5.2)	$0.0
Net loss (gain)	(75.7)	34.0	43.3	(15.6)	16.3	(7.4)
Amortization of:						
Actuarial gain (loss)	(21.5)	(15.3)	(12.2)	(1.0)	(0.1)	(0.1)
Prior service (benefit) cost	0.4	0.4	0.4	0.3	(0.8)	(0.8)
Transition obligation	0.0	0.0	0.0	0.0	(1.8)	(2.4)
Total recognized in OCI and regulatory assets	$ (96.8)	$ 19.1	$ 31.5	$ (16.3)	$ 8.4	$ (10.7)
Total Recognized in Net Periodic Benefit Cost, OCI and Regulatory Assets	$ (67.0)	$ 44.0	$ 51.8	$ (3.9)	$ 23.6	$ 5.7

TEC's portion of the net periodic benefit costs for pension benefits was $21.7 million, $18.3 million and $13.1 million for 2013, 2012 and 2011, respectively. TEC's portion of the net periodic benefit costs for other benefits was $10.0 million, $12.4 million and $10.0 million for 2013, 2012 and 2011, respectively.

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized by TEC from regulatory assets into net periodic benefit cost over the next fiscal year are $10.5 million and $0.5 million, respectively. There will be no remaining net loss for the other postretirement benefit plan that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year.

Assumptions used to determine net periodic benefit cost for years ended Dec. 31:

	Pension Benefits			Other Benefits		
	2013	*2012*	*2011*	*2013*	*2012*	*2011*
Discount rate	4.196%	4.797%	5.30%	4.180%	4.744%	5.25%
Expected long-term return on plan assets	7.50%	7.50%	7.75%	n/a	n/a	n/a
Rate of compensation increase	3.76%	3.83%	3.88%	3.74%	3.82%	3.87%
Healthcare cost trend rate						
Immediate rate	n/a	n/a	n/a	7.50%	7.75%	8.00%
Ultimate rate	n/a	n/a	n/a	4.50%	4.50%	4.50%
Year rate reaches ultimate	n/a	n/a	n/a	2025	2025	2023

The discount rate assumption used to determine the 2013 benefit cost was based on a cash flow matching technique developed by outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by S&P) corporate bonds available from the Barclays Capital database at the measurement date to meet the plan's year-by-year projected cash flows. The technique calculates all possible bond portfolios that produce adequate cash flows to pay the yearly benefits and then selects the portfolio with the highest yield and uses that yield as the recommended discount rate.

The expected return on assets assumption was based on historical returns, fixed income spreads and equity premiums consistent with the portfolio and asset allocation. A change in asset allocations could have a significant impact on the expected return on assets. Additionally, expectations of long-term inflation, real growth in the economy and a provision for active management and expenses paid were incorporated in the assumption. For the year ended Dec. 31, 2013, TECO Energy's pension plan experienced actual asset returns of approximately 12%.

The compensation 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.

A one-percentage-point change in assumed health care cost trend rates would have the following effect on TEC's expense:

(millions)	1% Increase	1% Decrease
Effect on periodic cost	$ 0.2	$ (0.2)

Pension Plan Assets

Pension plan assets (plan assets) are invested in a mix of equity and fixed income securities. TECO Energy's investment objective is to obtain above-average returns while minimizing volatility of expected returns and funding requirements over the long term. TECO Energy'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.

	Target Allocation	Actual Allocation, End of Year	
Asset Category		*2013*	*2012*
Equity securities	48%-54%	54%	55%
Fixed income securities	46%-52%	46%	45%
Total	100%	100%	100%

TECO Energy reviews the plan's asset allocation periodically and re-balances the investment mix to maximize asset returns, optimize the matching of investment yields with the plan's expected benefit obligations, and minimize pension cost and funding. TECO Energy, Inc. expects to take additional steps to more closely match plan assets with plan liabilities.

The plan's investments are held by a trust fund administered by JP Morgan Chase Bank, N.A. (JP Morgan). JP Morgan measures fair value using the procedures set forth below for all investments. When available, JP Morgan uses quoted market prices on investments traded on an exchange to determine fair value and classifies such items as Level 1. In some cases where a market exchange price is available, but the investments are traded in a secondary market, JP Morgan makes use of acceptable practical expedients to calculate fair value, and the company classifies these items as Level 2.

If observable transactions and other market data are not available, fair value is based upon third-party developed models that use, when available, current market-based or independently-sourced market parameters such as interest rates, currency rates or option volatilities. Items valued using third-party generated models are classified according to the lowest level input or value driver that is most significant to the valuation. Thus, an item may be classified in Level 3 even though there may be significant inputs that are readily observable.

As required by the fair value accounting standards, the investments are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The plan's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For cash equivalents, the cost approach was used in determining fair value. For bonds and U.S. government agencies, the income approach was used. For other investments, the market approach was used. The following table sets forth by level within the fair value hierarchy the plan's investments as of Dec. 31, 2013 and 2012.

Pension Plan Investments

(millions)	At Fair Value as of Dec. 31, 2013			
	Level 1	Level 2	Level 3	Total
Accounts receivable	$44.7	$0.0	$0.0	$44.7
Accounts payable	(40.8)	0.0	0.0	(40.8)
Cash equivalents				
STIFs	7.9	0.0	0.0	7.9
T bills	0.0	0.3	0.0	0.3
Repurchase agreements	0.0	8.8	0.0	8.8
Commercial paper	0.0	0.4	0.0	0.4
Money markets	0.0	1.5	0.0	1.5
Total cash equivalents	7.9	11.0	0.0	18.9
Equity securities				
Common stocks	91.6	0.0	0.0	91.6
ADRs	3.0	0.0	0.0	3.0
REITs	1.7	0.0	0.0	1.7
Preferred stock	0.0	0.8	0.0	0.8
Mutual funds	172.6	0.0	0.0	172.6
Commingled fund	0.0	50.0	0.0	50.0
Total equity securities	268.9	50.8	0.0	319.7
Fixed income securities				
Municipal bonds	0.0	7.3	0.0	7.3
Government bonds	0.0	35.7	0.0	35.7
Corporate bonds	0.0	19.6	0.0	19.6
ABS	0.0	0.4	0.0	0.4
MBS, net short sales	0.0	6.7	0.0	6.7
CMOs	0.0	2.3	0.0	2.3
Mutual funds	0.0	85.1	0.0	85.1
Commingled fund	0.0	94.1	0.0	94.1
Total fixed income securities	0.0	251.2	0.0	251.2
Derivatives				
Short futures	0.0	0.2	0.0	0.2
Swaps	0.0	(0.9)	0.0	(0.9)
Purchased options (swaptions)	0.0	0.2	0.0	0.2
Written options (swaptions)	0.0	(0.4)	0.0	(0.4)
Total derivatives	0.0	(0.9)	0.0	(0.9)
Miscellaneous	0.0	0.2	0.0	0.2
Total	$280.7	$312.3	$0.0	$593.0

Pension Plan Investments

(millions)	At Fair Value as of Dec. 31, 2012			
	Level 1	Level 2	Level 3	Total
Accounts receivable	$64.8	$0.0	$0.0	$64.8
Accounts payable	(72.8)	0.0	0.0	(72.8)
Cash equivalents				
STIFs	9.0	0.0	0.0	9.0
T bills	0.0	0.6	0.0	0.6
Repurchase agreements	0.0	23.1	0.0	23.1
CDs	0.0	1.1	0.0	1.1
Commercial paper	0.0	0.9	0.0	0.9
Money markets	0.0	0.6	0.0	0.6
Total cash equivalents	9.0	26.3	0.0	35.3
Equity securities				
Common stocks	125.3	0.0	0.0	125.3
ADRs	6.2	0.0	0.0	6.2
REITs	2.0	0.0	0.0	2.0
Preferred stocks	0.0	0.8	0.0	0.8
Equity mutual funds	153.4	0.0	0.0	153.4
Total equity securities	286.9	0.8	0.0	287.7
Fixed income securities				
Municipal bonds	0.0	8.0	0.0	8.0
Government bonds	0.0	53.0	0.0	53.0
Corporate bonds	0.0	19.8	0.0	19.8
ABS	0.0	0.5	0.0	0.5
MBS	0.0	17.6	0.0	17.6
CMBS	0.0	0.3	0.0	0.3
CMOs	0.0	2.5	0.0	2.5
Fixed income mutual fund	0.0	63.7	0.0	63.7
Fixed income commingled fund	0.0	49.4	0.0	49.4
Total fixed income securities	0.0	214.8	0.0	214.8
Derivatives				
Swaps	0.0	(0.5)	0.0	(0.5)
Purchased options (swaptions)	0.0	0.1	0.0	0.1
Written options (swaptions)	0.0	(0.4)	0.0	(0.4)
Total derivatives	0.0	(0.8)	0.0	(0.8)
Miscellaneous	0.0	0.1	0.0	0.1
Total	$287.9	$241.2	$0.0	$529.1

- The primary pricing inputs in determining the fair value of the Level 1 assets, excluding the mutual funds and STIF, are closing quoted prices in active markets.
- The STIF is valued at net asset value (NAV) as determined by JP Morgan. Shares may be redeemed any business day at the NAV calculated after the order is accepted. The NAV is validated with purchases and sales at NAV, making this a Level 1 asset.
- The primary pricing inputs in determining the Level 1 mutual funds are the mutual funds' NAVs. The funds are registered open-ended mutual funds and the NAVs are validated with purchases and sales at NAV, making these Level 1 assets.
- The repurchase agreements and money markets are valued at cost due to their short term nature. Additionally, repurchase agreements are backed by collateral.
- T bills and commercial paper are valued using benchmark yields, reported trades, broker dealer quotes, and benchmark securities.
- The primary pricing inputs in determining the fair value of the preferred stock is the price of underlying and common stock of the same issuer, average life, and benchmark yields.
- The methodology and inputs used to value the investment in the equity commingled fund are broker dealer quotes. The fund holds primarily international equity securities that are actively traded in OTC markets. The fund honors subscription and redemption activity on an "as of" basis.
- The primary pricing inputs in determining the fair value Level 2 municipal bonds are benchmark yields, historical spreads, sector curves, rating updates, and prepayment schedules. The primary pricing inputs in determining the fair value of

government bonds are the U.S. Treasury curve, CPI, and broker quotes, if available. The primary pricing inputs in determining the fair value of corporate bonds are the U.S. treasury curve, base spreads, YTM, and benchmark quotes. ABS and CMOs are priced using TBA prices, treasury curves, swap curves, cash flow information, and bids and offers as inputs. MBS are priced using TBA prices, treasury curves, average lives, spreads, and cash flow information. Commercial MBS are priced using payment information and yields.

- The primary pricing input in determining the fair value of the Level 2 mutual fund is its NAV. However, since this mutual fund is an unregistered open-ended mutual fund, it is a Level 2 asset.
- The fixed income commingled fund is a private fund valued at NAV as determined by a third party at year end. The fund invests in long duration U.S. investment-grade fixed income assets and seeks to increase return through active management of interest rate and credit risks. The NAV is calculated based on bid prices of the underlying securities. The fund honors subscription activity on the first business day of the month and the first business day following the 15th calendar day of the month. Redemptions are honored on the 15th or last business day of the month, providing written notice is given at least ten business days prior to withdrawal date.
- Futures are valued using futures data, cash rate data, swap rates, and cash flow analyses.
- Swaps are valued using benchmark yields, swap curves, and cash flow analyses.
- Options are valued using the bid-ask spread and the last price.

Other Postretirement Benefit Plan Assets

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

Contributions

TECO Energy's policy is to fund the qualified pension plan at or above amounts determined by its actuaries to meet ERISA guidelines for minimum annual contributions and minimize PBGC premiums paid by the plan. TECO Energy made $42.0 million of contributions to this plan in 2013 and $35.5 million in 2012, which met the minimum funding requirements for both 2013 and 2012. TEC's portion of the contribution in 2013 was $33.5 million and in 2012 was $27.9 million. These amounts are reflected in the "Other" line on the Consolidated Statements of Cash Flows. TECO Energy estimates its contribution in 2014 to be $47.5 million, with TEC's portion being $38.4 million. TECO Energy estimates it will make annual contributions from 2015 to 2018 ranging from $4.0 to $48.0 million per year based on current assumptions, with TEC's portion to range from $3 million to $39 million. These amounts are in excess of the minimum funding required under ERISA guidelines.

The SERP is funded annually to meet the benefit obligations. TECO Energy made contributions of $2.6 million and $1.3 million to this plan in 2013 and 2012, respectively. TEC's portion of the contributions in 2013 and 2012 were $1.0 million and $0.6 million, respectively. In 2014, TECO Energy expects to make a contribution of about $3.3 million to this plan. TEC's portion of the expected contribution is about $0.9 million.

The other postretirement benefits are funded annually to meet benefit obligations. TECO Energy's 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. TECO Energy's 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 2014, TECO Energy expects to make a contribution of about $13.3 million. TEC's portion of the expected contribution is $10.8 million. Postretirement benefit levels are substantially unrelated to salary.

Benefit Payments

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

Expected Benefit Payments - TECO Energy (including projected service and net of employee contributions) *(millions)*	**Pension Benefits**	**Other Postretirement Benefits**
2014	$ 53.5	$ 13.3
2015	50.9	13.9
2016	55.3	14.6
2017	55.9	15.2
2018	58.3	15.7
2019-2023	298.6	81.9

Defined Contribution Plan

TECO Energy has a defined contribution savings plan covering substantially all employees of TECO Energy and its subsidiaries that enables participants to save a portion of their compensation up to the limits allowed by IRS guidelines. TECO Energy and its subsidiaries match up to 6% of the participant's payroll savings deductions. Employer matching contributions are 60% of eligible participant contributions with additional incentive match of up to 40% of eligible participant contributions based on the achievement of certain operating company financial goals. For the years ended Dec. 31, 2013, 2012 and 2011, TECO Energy and its subsidiaries recognized expense totaling $11.3 million, $7.0 million and $9.0 million, respectively, related to the matching contributions made to this plan. TEC's portion of expense totaled $9.1 million, $6.0 million and $5.8 million for 2013, 2012 and 2011, respectively.

6. Short-Term Debt

At Dec. 31, 2013 and 2012, the following credit facilities and related borrowings existed:

Credit Facilities

	Dec. 31, 2013			*Dec. 31, 2012*		
(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 [2]	$325.0	$6.0	$0.7	$325.0	$0.0	$1.5
1-year accounts receivable facility	150.0	78.0	0.0	150.0	0.0	0.0
Total	$475.0	$84.0	$0.7	$475.0	$0.0	$1.5

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.

At Dec. 31, 2013, these credit facilities require commitment fees ranging from 12.5 to 25.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at Dec. 31, 2013 was 0.56%. There were no outstanding borrowings at Dec. 31, 2012.

Tampa Electric Company Accounts Receivable Facility

On Feb. 14, 2014, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 12 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A., Inc. as Program Agent. The amendment extends the maturity date to Feb. 13, 2015 and makes certain other technical changes. Please refer to **Note 16** for additional information.

Amendment of Tampa Electric Company Credit Facility

On Dec. 17, 2013, TEC amended and restated its $325 million bank credit facility, entering into a Fourth Amended and Restated Credit Agreement. The amendment (i) extends the maturity date of the credit facility from Oct. 25, 2016 to Dec. 17, 2018 (subject to further extension with the consent of each lender); (ii) continues to allow TEC to borrow funds at a rate equal to the London interbank deposit rate plus a margin; (iii) as an alternative to the above interest rate, allows TEC to borrow funds at an interest rate equal to a margin plus the higher of Citibank's prime rate, the federal funds rate plus 50 basis points, or the London interbank deposit rate plus 1.00%; (iv) allows TEC to borrow funds on a same-day basis under a swingline loan provision, which loans mature on the fourth banking day after which any such loans are made and bear interest at an interest rate as agreed by the borrower and the relevant swingline lender prior to the making of any such loans; (v) continues to allow TEC to request the lenders to increase their commitments under the credit facility by up to $175 million in the aggregate; (vi) includes a $200 million letter of credit facility; and (vii) made other technical changes.

7. Long-Term Debt

A substantial part of Tampa Electric's tangible assets are pledged as collateral to secure its first mortgage bonds. There are currently no bonds outstanding under Tampa Electric's first mortgage bond indenture.

Purchase in Lieu of Redemption of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 B

On Sept. 3, 2013, TEC purchased in lieu of redemption $51.6 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 B (the Series 2007 B HCIDA Bonds). On March 26, 2008, the HCIDA had remarketed the Series 2007 B HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2007 B HCIDA Bonds bore interest at a term rate of 5.15% per annum from March 26, 2008 to Sept. 1, 2013. TEC is responsible for payment of the interest and principal associated with the Series 2007 B HCIDA Bonds.

On March 15, 2012, TEC purchased in lieu of redemption $86.0 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2006 (Non-AMT) (the Series 2006 HCIDA Bonds). On March 19, 2008, the HCIDA had remarketed the Series 2006 HCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. The Series 2006 HCIDA Bonds bore interest at a term rate of 5.00% per annum from March 19, 2008 to March 15, 2012. TEC is responsible for payment of the interest and principal associated with the Series 2006 HCIDA Bonds. Regularly scheduled principal and interest when due, are insured by Ambac Assurance Corporation.

On March 1, 2011, TEC purchased in lieu of redemption $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2010 (the PCIDA Bonds). On Nov. 23, 2010, the PCIDA had issued the PCIDA Bonds in a term-rate mode pursuant to the terms of the Loan and Trust Agreement governing those bonds. Proceeds of the PCIDA Bonds were used to redeem $75.0 million PCIDA Solid Waste Disposal Facility Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007, which previously had been in auction rate mode and had been held by TEC since March 26, 2008. The PCIDA Bonds bore interest at the initial term rate of 1.50% per annum from Nov. 23, 2010 to March 1, 2011.

On March 26, 2008, TEC purchased in lieu of redemption $20 million HCIDA Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2007 C.

After the Sept. 3, 2013 purchase of the Series 2007 B HCIDA Bonds, $232.6 million in bonds purchased in lieu of redemption were held by the trustee at the direction of TEC as of Dec. 31, 2013 to provide an opportunity to evaluate refinancing alternatives.

Redemption of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2002

On Oct. 1, 2012, TEC redeemed $147.1 million of Hillsborough County Industrial Development Authority Pollution Control Revenue Refunding Bonds (Tampa Electric Company Project), Series 2002 due Oct. 1, 2013 and Oct. 1, 2023 (the 2002 Bonds) at a redemption price equal to 100% of the principal amount of the 2002 Bonds to be redeemed, plus accrued and unpaid interest to Oct. 1, 2012. Before the optional redemption, $60.7 million of the 2002 Bonds due Oct. 1, 2013 bore interest at 5.1% and $86.4 million of the 2002 Bonds due Oct. 1, 2023 bore interest at 5.5%.

Issuance of Tampa Electric Company 2.60% Notes due 2022

On Sept. 28, 2012, TEC completed an offering of $250 million aggregate principal amount of 2.60% Notes due 2022 (the 2022 Notes). The 2022 Notes were sold at 99.878% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $247.7 million. Net proceeds were used to repay the 2002 Bonds. The remaining net proceeds were used to repay short-term debt and for general corporate purposes. At any time prior to June 15, 2022, TEC may redeem all or any part of the 2022 Notes at its option at a redemption price equal to the greater of (i) 100% of the principal amount of 2022 Notes to be redeemed or (ii) the sum of the present values of the remaining payments of principal and interest on the 2022 Notes to be redeemed, discounted to the redemption date on a semiannual basis at an applicable treasury rate, plus 15 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after June 15, 2022, TEC may at its option redeem the 2022 Notes, in whole or in part, at 100% of the principal amount of the 2022 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

Issuance of Tampa Electric Company 4.10% Notes due 2042

On June 5, 2012, TEC completed an offering of $300 million aggregate principal amount of 4.10% Notes due 2042 (the 2042 Notes). The 2042 Notes were sold at 99.724% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, and estimated offering expenses and before settlement of interest rate swaps) of approximately $296.2 million. Net proceeds were used to repay maturing long-term debt, to repay short-term debt and for general corporate purposes. At any time prior to Dec. 15, 2041, TEC may redeem all or any part of the 2042 Notes at its option and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of the 2042 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the 2042 Notes to be redeemed, discounted at an applicable treasury rate, plus 25 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Dec. 15, 2041, TEC may at its option redeem the 2042 Notes, in whole or in part, at 100% of the principal amount of the 2042 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

8. Other Comprehensive Income

TEC reported the following OCI (loss) for the years ended Dec. 31, 2013, 2012 and 2011, related to the amortization of prior settled amounts and changes in the fair value of cash flow hedges:

Other Comprehensive Income *(millions)*	Gross	Tax	Net
2013			
Unrealized gain (loss) on cash flow hedges	$0.0	$0.0	$0.0
Reclassification from AOCI to net income	1.4	(0.5)	0.9
Gain (Loss) on cash flow hedges	1.4	(0.5)	0.9
Total other comprehensive income (loss)	$1.4	($0.5)	$0.9
2012			
Unrealized (loss) gain on cash flow hedges	($8.0)	$3.1	($4.9)
Reclassification from AOCI to net income	1.4	(0.6)	0.8
(Loss) Gain on cash flow hedges	(6.6)	2.5	(4.1)
Total other comprehensive (loss) income	($6.6)	$2.5	($4.1)
2011			
Unrealized gain (loss) on cash flow hedges	$0.0	$0.0	$0.0
Reclassification from AOCI to net income	1.2	(0.5)	0.7
Gain (Loss) on cash flow hedges	1.2	(0.5)	0.7
Total other comprehensive income (loss)	$1.2	($0.5)	$0.7

Accumulated Other Comprehensive Loss *(millions) As of Dec. 31,*	*2013*	*2012*
Net unrealized losses from cash flow hedges [1]	($7.8)	($8.7)
Total accumulated other comprehensive loss	($7.8)	($8.7)

(1) Net of tax benefit of $4.9 million and $5.5 million as of Dec. 31, 2013 and Dec. 31, 2012, respectively.

9. Commitments and Contingencies

Legal Contingencies

From time to time, TEC and its subsidiaries are involved in various 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 accounting standards for contingencies to provide for matters that are probable of resulting in an estimable 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, financial condition or cash flows.

Legal Proceedings

In November 2010, heavy equipment operated at a road construction site being conducted by Posen Construction, Inc. struck a natural gas line causing a rupture and ignition of the gas and an outage in the natural gas service to Lee and Collier counties, Florida. In December 2010, two commercial PGS customers filed a purported class action in Lee County Circuit Court, Florida against PGS on behalf of PGS commercial customers affected by the outage, seeking damages for loss of revenue and other costs related to the gas outage. Posen Construction, Inc., the company conducting construction at the site where the incident occurred, is also a defendant in the action. In June 2013, the court denied the plaintiffs' motion for class certification and dismissed the plaintiffs' underlying claim against PGS. The Court's order is now final and not appealable. PGS filed suit in April 2011 against Posen Construction, Inc. in Federal Court for the Middle District of Florida to recover damages for repair and restoration relating to the incident and Posen Construction, Inc. counter-claimed against PGS alleging negligence. In the first quarter of 2014, the parties entered into a settlement agreement that resolves the claims of the parties. In addition, the suit filed in November 2011 by the Posen Construction, Inc. employee operating the heavy equipment involved in the incident in Lee County Circuit Court against PGS, Posen Construction, Inc. and a PGS contractor involved in the project, seeking damages for his injuries, also remains pending.

In addition, three former or inactive TEC employees are maintaining a suit against TEC in Hillsborough County Circuit Court, Florida for personal injuries allegedly caused by exposure to a chemical substance at one of TEC's power stations. The suit was originally filed in 2002, and the trial judge allowed the plaintiffs to seek punitive damages in connection with their case. In the first quarter of 2014, the attorneys for the plaintiffs withdrew from representation. A trial is expected sometime in 2014.

TEC believes the claims in each of the pending actions described above in this item are without merit and intends to defend each matter vigorously. TEC is unable at this time to estimate the possible loss or range of loss with respect to these matters.

Environmental Protection Agency Section 114 Letter

On Feb. 11, 2013, TEC received an information request from the EPA under Section 114(a) of the CAA seeking documents and other information concerning the compliance status of its sulfuric acid plant at its Polk Power Station in Polk County, Florida with the "New Source Review" requirements of the CAA. The request received by TEC appears to be part of a broader EPA national enforcement initiative focusing on sulfuric acid plants. TEC cannot predict at this time what the scope of this matter will ultimately be or the range of outcomes, and therefore it is not able to estimate the possible loss or range of loss, if any, with respect to this matter. TEC responded with the requested information on April 26, 2013 and has not received any response from the EPA on this matter.

Superfund and Former Manufactured Gas Plant Sites

TEC, through its Tampa Electric and Peoples Gas divisions, is a 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, 2013, TEC has estimated its ultimate financial liability to be $40.4 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Other" on the Consolidated Balance Sheets. 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 portion of the cleanup costs attributable to TEC. The estimates to perform the work are based on TEC'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.

In instances where other PRPs are involved, most of those PRPs are creditworthy and are likely to continue to be creditworthy for the duration of the remediation work. However, in those instances that they are not, TEC could be liable for more than TEC's actual percentage of the remediation costs.

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. Under current regulations, these costs are recoverable through customer rates established in subsequent base rate proceedings.

Long-Term Commitments

TEC has commitments under long-term leases, primarily for building space, capacity payments, office equipment and heavy equipment. Total rental expense for these leases, included in "Regulated operations & maintenance – Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2013, 2012 and 2011, totaled $2.3 million, $2.2 million and $2.2 million, respectively. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year and capacity payments under PPAs at Dec. 31, 2013:

Future Minimum Lease and Capacity Payments

(millions)	*Capacity Payments*	*Operating Leases*	*Total*
Year ended Dec. 31:			
2014	$14.8	$2.3	$17.1
2015	14.9	2.3	17.2
2016	14.6	2.2	16.8
2017	9.9	2.2	12.1
2018	10.1	2.2	12.3
Thereafter	0.0	13.4	13.4
Total future mimimum payments	$64.3	$24.6	$88.9

Guarantees and Letters of Credit

TEC accounts for guarantees in accordance with the applicable accounting standards. 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) are likely to be subject to the recognition and measurement, as well as the disclosure provisions. 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.

At Dec. 31, 2013, TEC was not obligated under guarantees, but had $0.7 million of letters of credit outstanding.

Letters of Credit - Tampa Electric Company

(millions) *Letters of Credit for the Benefit of:*	*2014*	*2015-2018*	*After [(1)] 2018*	*Total*	*Liabilities Recognized at Dec. 31, 2013*
Tampa Electric [(2)]					
Letters of credit	$0.0	$ 0.0	$0.7	$0.7	$0.1

(1) These letters of credit renew annually and are shown on the basis that they will continue to renew beyond 2018.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation of TEC under these agreements at Dec. 31, 2013. The obligations under these letters of credit include net accounts payable and net derivative liabilities.

Financial Covenants

In order to utilize their respective bank credit facilities, TEC must meet certain financial tests as defined in the applicable agreements. In addition, TEC has certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2013, TEC was in compliance with all required financial covenants.

10. Related Party Transactions

A summary of activities between TEC and its affiliates follows:

Net transactions with affiliates:

(millions)	*2013*	*2012*	*2011*
Natural gas sales, net	$ 18.3	$ 11.7	$ 0.0
Administrative and general, net	$ 27.2	$ 23.4	$ 17.5

Amounts due from or to affiliates at Dec. 31,

(millions)	*2013*	*2012*
Accounts receivable [(1)]	$ 1.3	$ 4.7
Accounts payable [(1)]	9.8	7.9
Taxes receivable	54.9	22.1
Taxes payable	0.4	3.2

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest.

TEC had certain transactions, in the ordinary course of business, with entities in which directors of TEC had interests. TEC paid legal fees of $1.7 million, $1.2 million and $1.3 million for the years ended Dec. 31, 2013, 2012 and 2011, respectively, to Ausley McMullen, P.A. of which Mr. Ausley (who was a director of TECO Energy, until his retirement from the Board in May 2013) was an employee.

11. Segment Information

TEC is a public utility operating within the State of Florida. Through its Tampa Electric division, it is engaged in the generation, purchase, transmission, distribution and sale of electric energy to almost 700,000 customers in West Central Florida. Its PGS division is engaged in the purchase, distribution and marketing of natural gas for almost 350,000 residential, commercial, industrial and electric power generation customers in the State of Florida.

(millions)	Tampa Electric	PGS	Other & Eliminations	TEC
2013				
Revenues - external	$1,950.1	$392.7	$0.0	$2,342.8
Sales to affiliates	0.4	0.8	(1.2)	0.0
Total revenues	1,950.5	393.5	(1.2)	2,342.8
Depreciation and amortization	238.8	51.5	0.0	290.3
Total interest charges	91.8	13.5	0.0	105.3
Provision for income taxes	116.9	21.9	0.0	138.8
Net income	190.9	34.7	0.0	225.6
Total assets	5,895.4	989.3	(8.9)	6,875.8
Capital expenditures	428.6	79.0	0.0	507.6
2012				
Revenues - external	$1,980.9	$397.1	$0.0	$2,378.0
Sales to affiliates	0.4	1.8	(2.2)	0.0
Total revenues	1,981.3	398.9	(2.2)	2,378.0
Depreciation and amortization	237.6	50.6	0.0	288.2
Total interest charges	109.8	16.0	0.0	125.8
Provision for income taxes	120.2	21.5	0.0	141.7
Net income	193.1	34.1	0.0	227.2
Total assets	5,760.4	970.9	13.3	6,744.6
Capital expenditures	361.7	97.3	0.0	459.0
2011				
Revenues - external	$2,020.1	$450.5	$0.0	$2,470.6
Sales to affiliates	0.5	3.0	(3.5)	0.0
Total revenues	2,020.6	453.5	(3.5)	2,470.6
Depreciation and amortization	222.1	48.4	0.0	270.5
Total interest charges	121.8	17.7	0.0	139.5
Provision for income taxes	124.8	20.6	0.0	145.4
Net income	202.7	32.6	0.0	235.3
Total assets	5,678.0	888.4	(10.0)	6,556.4
Capital expenditures	314.9	71.9	0.0	386.8

12. Asset Retirement Obligations

TEC accounts for AROs under the applicable accounting standards. An 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.

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. TEC 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.

For the year ended Dec. 31, 2012, $27.6 million of liabilities settled resulted primarily from asbestos abatement and other dismantling at the generating stations at Tampa Electric.

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

(millions)	*Dec. 31, 2013*	*2012*
Beginning balance	$ 5.0	$ 30.8
Additional liabilities	0.1	0.0
Liabilities settled	(0.2)	(27.6)
Revisions to estimated cash flows	(0.3)	0.0
Other [1]	0.2	1.8
Ending balance	$ 4.8	$ 5.0

(1) Accretion recorded as a deferred regulatory asset.

13. Accounting for Derivative Instruments and Hedging Activities

From time to time, TEC enters 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, and
- To limit the exposure to interest rate fluctuations on debt securities.

TEC uses derivatives only to reduce normal operating and market risks, not for speculative purposes. TEC'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 TEC 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.

TEC applies the accounting standards for 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 (see **Note 14**). 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 loss on the related hedging instrument must be reclassified from OCI to earnings based on its value at the time of the instrument's settlement. For effective hedge transactions, the amount reclassified from OCI to earnings is offset in net income by the market change of the amount paid or received on the underlying physical transaction.

TEC applies the accounting standards for regulated operations to financial instruments used to hedge the purchase of natural gas for its regulated companies. These standards, in accordance with the FPSC, permit the changes in fair value of natural gas derivatives to be recorded as regulatory assets or liabilities reflecting the impact of hedging activities on the fuel recovery clause. As a result, these changes are not recorded in OCI (see **Note 3**).

TEC's physical contracts qualify for the NPNS exception to derivative accounting rules, provided they meet certain criteria. Generally, NPNS applies if TEC deems the counterparty creditworthy, if the counterparty owns or controls resources within the proximity to allow for physical delivery of the commodity, if TEC intends to receive physical delivery and if the transaction is reasonable in relation to TEC's business needs. As of Dec. 31, 2013, all of TEC's physical contracts qualify for the NPNS exception.

The following table presents the derivative cash flow hedges of natural gas contracts at Dec. 31, 2013 and Dec. 31, 2012 to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers:

Natural Gas Derivatives [1]

(millions)	*Dec. 31, 2013*	*Dec. 31, 2012*
Current assets	$9.5	$0.0
Long-term assets	0.3	0.2
Total assets	$9.8	$0.2
Current liabilities	$0.0	$14.1
Long-term liabilities	0.2	0.2
Total liabilities	$0.2	$14.3

(1) Amounts presented above are on a gross basis, with asset and liability positions netted by counterparty in accordance with

accounting standards for derivatives and hedging.

The following table presents the gross amounts of derivatives and their related offset amounts as permitted by their respective master netting agreements at Dec. 31, 2013 and Dec. 31, 2012. There was no collateral posted with or received from any counterparties.

Offsetting of Derivative Assets and Liabilities
(millions)

	Gross Amounts of Recognized Assets (Liabilities)	Gross Amounts Offset on the Balance Sheet	Net Amounts of Assets (Liabilities) Presented on the Balance Sheet
Dec. 31, 2013			
Description			
Derivative assets	$ 10.3	$ (0.5)	$ 9.8
Derivative liabilities	$ (0.7)	$ 0.5	$ (0.2)
Dec. 31, 2012			
Description			
Derivative assets	$ 1.0	$ (0.8)	$ 0.2
Derivative liabilities	$ (15.1)	$ 0.8	$ (14.3)

The ending balance in AOCI related to previously settled interest rate swaps at Dec. 31, 2013 is a net loss of $7.8 million after tax and accumulated amortization. This compares to a net loss of $8.7 million in AOCI after tax and accumulated amortization at Dec. 31, 2012.

The following table presents the effect of energy related derivatives on the fuel recovery clause mechanism on the Consolidated Balance Sheets as of Dec. 31, 2013 and 2012:

Energy Related Derivatives

	Asset Derivatives		Liability Derivatives	
(millions) *at Dec. 31, 2013*	Balance Sheet Location (1)	Fair Value	Balance Sheet Location (1)	Fair Value
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$9.5	Regulatory assets	$0.0
Long-term	Regulatory liabilities	0.3	Regulatory assets	0.2
Total		$9.8		$0.2
(millions) *at Dec. 31, 2012*	Balance Sheet Location (1)	Fair Value	Balance Sheet Location (1)	Fair Value
Commodity Contracts:				
Natural gas derivatives:				
Current	Regulatory liabilities	$0.0	Regulatory assets	$14.1
Long-term	Regulatory liabilities	0.2	Regulatory assets	0.2
Total		$0.2		$14.3

(1) Natural gas derivatives are deferred in accordance with accounting standards for regulated operations and all increases and decreases in the cost of natural gas supply are passed on to customers with the fuel recovery clause mechanism. As gains and losses are realized in future periods, they will be recorded as fuel costs in the Consolidated Statements of Income.

Based on the fair value of the instruments at Dec. 31, 2013, net pretax losses of $9.5 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The following table presents the effect of hedging instruments on OCI and income for the years ended Dec. 31, 2013, 2012 and 2011:

(millions) *For the years ended Dec. 31:*	Location of Gain/(Loss) Reclassified From AOCI Into Income	Amount of Gain/(Loss) Reclassified From AOCI Into Income *2013*	*2012*	*2011*
Derivatives in Cash Flow Hedging Relationships	Effective Portion (1)			
Interest rate contracts:	Interest expense	($0.9)	($0.8)	($0.7)
Total		($0.9)	($0.8)	($0.7)

(1) Changes in OCI and AOCI are reported in after-tax dollars.

For derivative instruments that meet cash flow hedge criteria, the effective portion of the gain or loss on the derivative is reported as a component of OCI and reclassified into earnings in the same period or period during which the hedged transaction affects earnings. Gains and losses on the derivatives representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings. For the years ended Dec. 31, 2013, 2012 and 2011, all hedges were effective.

The maximum length of time over which TEC is hedging its exposure to the variability in future cash flows extends to Dec. 31, 2015 for the financial natural gas contracts. The following table presents by commodity type TEC's derivative volumes that, as of Dec. 31, 2013, are expected to settle during the 2014 and 2015 fiscal years:

(millions)	Natural Gas Contracts (MMBTUs)	
Year	Physical	Financial
2014	0.0	36.9
2015	0.0	7.6
Total	0.0	44.5

TEC is exposed to credit risk primarily through entering into derivative instruments with counterparties to limit its exposure to the commodity price fluctuations associated with natural gas. Credit risk is the potential loss resulting from a counterparty's nonperformance under an agreement. TEC manages credit risk with policies and procedures for, among other things, counterparty analysis, exposure measurement and exposure monitoring and mitigation.

It is possible that volatility in commodity prices could cause TEC to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, TEC could suffer a material financial loss. However, as of Dec. 31, 2013, substantially all of the counterparties with transaction amounts outstanding in TEC's energy portfolio were rated investment grade by the major rating agencies. TEC assesses credit risk internally for counterparties that are not rated.

TEC has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. TEC generally enters into the following master arrangements: (1) EEI agreements- standardized power sales contracts in the electric industry; (2) ISDA agreements- standardized financial gas and electric contracts; and (3) NAESB agreements - standardized physical gas contracts. TEC believes that entering into such agreements reduces the risk from default by creating contractual rights relating to creditworthiness, collateral and termination.

TEC has implemented procedures to monitor the creditworthiness of its counterparties and to consider nonperformance risk in determining the fair value of counterparty positions. Net liability positions are generally not adjusted as TEC uses derivative transactions as hedges and has the ability and intent to perform under each of these contracts. In the instance of net asset positions, TEC considers general market conditions and the observable financial health and outlook of specific counterparties in evaluating the potential impact of nonperformance risk to derivative positions. As of Dec. 31, 2013, substantially all positions with counterparties were net assets.

Certain TEC derivative instruments contain provisions that require TEC's debt to maintain an investment grade credit rating from any or all of the major credit rating agencies. If debt ratings were to fall below investment grade, it could trigger these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. TEC has no other contingent risk features associated with any derivative instruments. Substantially all of TEC's open positions with counterparties as of Dec. 31, 2013 were asset positions.

14. Fair Value Measurements

Items Measured at Fair Value on a Recurring Basis

The following table sets forth by level within the fair value hierarchy TEC's financial assets and liabilities that were accounted for at fair value on a recurring basis as of Dec. 31, 2013 and 2012. As required by accounting standards for fair value measurements, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. TEC's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. For all assets and liabilities presented below, the market approach was used in determining fair value.

Recurring Derivative Fair Value Measures

	At fair value as of Dec. 31, 2013			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ 0.0	$9.8	$ 0.0	$9.8
Total	$ 0.0	$9.8	$ 0.0	$9.8
Liabilities				
Natural gas swaps	$ 0.0	$0.2	$ 0.0	$0.2
Total	$ 0.0	$0.2	$ 0.0	$0.2

	At fair value as of Dec. 31, 2012			
(millions)	*Level 1*	*Level 2*	*Level 3*	*Total*
Assets				
Natural gas swaps	$ 0.0	$0.2	$ 0.0	$0.2
Total	$ 0.0	$0.2	$ 0.0	$0.2
Liabilities				
Natural gas swaps	$ 0.0	$14.3	$ 0.0	$14.3
Total	$ 0.0	$14.3	$ 0.0	$14.3

Natural gas swaps are OTC swap instruments. The primary pricing inputs in determining the fair value of natural gas swaps are the NYMEX quoted closing prices of exchange-traded instruments. These prices are applied to the notional amounts of active positions to determine the reported fair value (see **Note 13**).

TEC considered the impact of nonperformance risk in determining the fair value of derivatives. TEC considered the net position with each counterparty, past performance of both parties, the intent of the parties, indications of credit deterioration and whether the markets in which TEC transacts have experienced dislocation. At Dec. 31, 2013, the fair value of derivatives was not materially affected by nonperformance risk. TEC's net positions with substantially all counterparties were liability positions. There were no Level 3 assets or liabilities during the 2013 or 2012 fiscal years.

15. Variable Interest Entities

The determination of a VIE's primary beneficiary is the enterprise that has both 1) the power to direct the activities of a VIE that most significantly impact the entity's economic performance and 2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

TEC has entered into multiple PPAs with wholesale energy providers in Florida to ensure the ability to meet customer energy demand and to provide lower cost options in the meeting of this demand. These agreements range in size from 117 MW to 370 MW of available capacity, are with similar entities and contain similar provisions. Because some of these provisions provide for the transfer or sharing of a number of risks inherent in the generation of energy, these agreements meet the definition of being VIEs. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. TEC has reviewed these risks and has determined that the owners of these entities have retained the majority of these risks over the expected life of the underlying generating assets, have the power to direct the most significant activities, the obligation or right to absorb losses or benefits and hence remain the primary beneficiaries. As a result, TEC is not required to consolidate any of these entities. TEC purchased $22.1 million, $75.8 million and $81.2 million, under these PPAs for the three years ended Dec. 31, 2013, 2012 and 2011, respectively.

In one instance, TEC's agreement with an entity for 370 MW of capacity was entered into prior to Dec. 31, 2003, the effective date of these standards. Under these standards, TEC is required to make an exhaustive effort to obtain sufficient information to determine if this entity is a VIE and which holder of the variable interests is the primary beneficiary. The owners of this entity are not willing to provide the information necessary to make these determinations, have no obligation to do so and the information is not available publicly. As a result, TEC is unable to determine if this entity is a VIE and, if so, which variable interest holder, if any, is the primary beneficiary. TEC has no obligation to this entity beyond the purchase of capacity; therefore, the maximum exposure for TEC is the obligation to pay for such capacity under terms of the PPA at rates that could be unfavorable to the wholesale market. TEC purchased $46.6 million and $34.4 million for the two years ended Dec. 31, 2012 and 2011, respectively. This PPA expired on Dec. 31, 2012.

The company does not provide any material financial or other support to any of the VIEs it is involved with, nor is the company under any obligation to absorb losses associated with these VIEs. In the normal course of business, the company's involvement with these VIEs does not affect its Consolidated Balance Sheets, Statements of Income or Cash Flows.

16. Subsequent Events

On Feb. 14, 2014, TEC and TRC amended their $150 million accounts receivable collateralized borrowing facility, entering into Amendment No. 12 to the Loan and Servicing Agreement with certain lenders named therein and Citibank, N.A. as Program Agent. The amendment (i) extends the maturity date to Feb. 13, 2015, (ii) provides that TRC will pay program and liquidity fees, which will total 70.0 basis points, (iii) continues to provide that the interest rates on the borrowings will be based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to, at TEC's option, either Citibank's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the LIBOR (if available) plus a margin, (iv) confirms that CAFCO, LLC will be the Committed Lender and Conduit Lender and (v) makes other technical changes.

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

None.

Item 9A. CONTROLS AND PROCEDURES.

TECO Energy, Inc.

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

TECO Energy's management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of TECO Energy's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this annual report, Dec. 31, 2013 (Evaluation Date). Based on such evaluation, TECO Energy's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, TECO Energy's disclosure controls and procedures are effective.

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 TECO Energy, Inc.'s internal control over financial reporting as of Dec. 31, 2013 based on the 1992 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 TECO Energy, Inc.'s internal control over financial reporting was effective as of Dec. 31, 2013.

TECO Energy's internal control over financial reporting as of Dec. 31, 2013 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which is on page 73 of this report.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. A control system, no matter how well designed and operated, can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

Changes in Internal Control over Financial Reporting.

There was no change in TECO Energy's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of TECO Energy's internal controls that occurred during TECO Energy's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Tampa Electric Company

Conclusions Regarding Effectiveness of Disclosure Controls and Procedures.

TEC's management, with the participation of its principal executive officer and principal financial officer, has evaluated the effectiveness of TEC's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (Exchange Act)) as of the end of the period covered by this annual report, Dec. 31, 2013 (Evaluation Date). Based on such evaluation, TEC's principal executive officer and principal financial officer have concluded that, as of the Evaluation Date, TEC's disclosure controls and procedures are effective.

Management's Report on Internal Control over Financial Reporting.

TEC's 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 TEC's internal control over financial reporting as of Dec. 31, 2013 based on the 1992 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 TEC's internal control over financial reporting was effective as of Dec. 31, 2013.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. A control system, no matter how well designed and operated, can provide only reasonable assurance with respect to financial statement preparation and presentation. 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.

Changes in Internal Control over Financial Reporting.

There was no change in Tampa Electric Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) identified in connection with the evaluation of Tampa Electric Company's internal controls that occurred during Tampa Electric Company's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

Item 9B. OTHER INFORMATION.

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

(a) The information required by Item 10 with respect to the directors of the registrant is included under the caption "Election of Directors" in TECO Energy's definitive proxy statement for its Annual Meeting of Shareholders to be held on April 30, 2014 (Proxy Statement) and is incorporated herein by reference.

(b) The information required by Item 10 concerning executive officers of the registrant is included under the caption "Executive Officers of the Registrant" on page 24 of this report.

(c) The information required by Item 10 concerning Section 16(a) Beneficial Ownership Reporting Compliance is included under that caption in the Proxy Statement and is incorporated herein by reference.

(d) Information regarding TECO Energy's Audit Committee, including the committee's financial experts, is included under the caption "Committees of the Board" in the Proxy Statement, and is incorporated herein by reference.

(e) TECO Energy has adopted a code of ethics applicable to all of its employees, officers and directors. The text of the *Code of Ethics and Business Conduct* is available in the Corporate Governance section of the Investors page of the company's website at www.tecoenergy.com. Any amendments to or waivers of the *Code of Ethics and Business Conduct* for the benefit of any executive officer or director will also be posted on the website.

Item 11. EXECUTIVE COMPENSATION.

The information required by Item 11 is included in the Proxy Statement beginning with the caption "Compensation Committee Report" and ending with "Post-Termination Benefits Table" just above the caption "Ratification of Appointment of Independent Auditor" and is incorporated herein by reference.

Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information required by Item 12 is included under the captions "Equity Compensation Plan Information" and "Share Ownership" in the Proxy Statement, and is incorporated herein by reference.

Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

The information required by Item 13 is included under the captions "Certain Relationships and Related Person Transactions" and "Director Independence" in the Proxy Statement, and is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.

The information required by Item 14 for TECO Energy is included under the caption "Item 2 – Ratification of Appointment of Independent Auditor" in the Proxy Statement and is incorporated herein by reference.

TEC incurred $0.8 million, $0.8 million and $0.7 million in audit-related fees rendered by PricewaterhouseCoopers for each of the years 2013, 2012 and 2011, respectively, including $0.3 million related to Sarbanes-Oxley in each of those three years. No other fees for services rendered by PricewaterhouseCoopers were incurred by TEC in those years.

PART IV

Item 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES.

(a) **Certain Documents Filed as Part of this Form 10-K**

1. Financial Statements
   TECO Energy, Inc. Financial Statements – See index on page 72
   Tampa Electric Company Financial Statements – See index on page 122
2. Financial Statement Schedules
   TECO Energy, Inc. Schedule II – page 158
   Tampa Electric Company Schedule II – page 159
3. Exhibits – See index beginning on page 163

(b) The exhibits filed as part of this Form 10-K are listed on the Exhibit Index immediately preceding such Exhibits. The Exhibit Index is incorporated herein by reference.

(c) The financial statement schedules filed as part of this Form 10-K are listed in paragraph (a)(2) above, and follow immediately.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TECO ENERGY, INC.
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2013, 2012 and 2011
(millions)

	Balance at Beginning of Period	Additions: Charged to Income	Additions: Other Charges	Payments & Deductions (1)	Balance at End of Period
Allowance for Uncollectible Accounts:					
2013	$ 4.2	$ 3.3	$ 0.0	$ 2.8	$ 4.7
2012	$ 2.6	$ 4.8	$ 0.0	$ 3.2	$ 4.2
2011	$ 4.5	$ 3.8	$ 0.0	$ 5.7	$ 2.6

----
(1) Write-off of individual bad debt accounts

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

TAMPA ELECTRIC COMPANY
VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
For the Years Ended Dec. 31, 2013, 2012 and 2011
(millions)

	Balance at Beginning of Period	Additions		Payments & Deductions [1]	Balance at End of Period
		Charged to Income	Other Charges		
Allowance for Uncollectible Accounts:					
2013	$ 1.5	$ 3.3	$ 0.0	$ 2.8	$ 2.0
2012	$ 1.3	$ 3.4	$ 0.0	$ 3.2	$ 1.5
2011	$ 3.2	$ 3.8	$ 0.0	$ 5.7	$ 1.3

----
(1) Write-off of individual bad debt accounts

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TECO ENERGY, INC.

Dated: February 28, 2014

By: /s/ JOHN B. RAMIL
JOHN B. RAMIL
President, Chief Executive Officer and Director
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 28, 2014:

Signature	Title
/s/ JOHN B. RAMIL JOHN B. RAMIL	President, Chief Executive Officer and Director (Principal Executive Officer)
/s/ SANDRA W. CALLAHAN SANDRA W. CALLAHAN	Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer) (Principal Financial and Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ JAMES L. FERMAN, JR. JAMES L. FERMAN, JR.	Director	/s/ LORETTA A. PENN LORETTA A. PENN	Director
/s/ EVELYN V. FOLLIT EVELYN V. FOLLIT	Director	/s/ TOM L. RANKIN TOM L. RANKIN	Director
/s/ SHERRILL W. HUDSON SHERRILL W. HUDSON	Chairman of the Board and Director	/s/ WILLIAM D. ROCKFORD WILLIAM D. ROCKFORD	Director
/s/ JOSEPH P. LACHER JOSEPH P. LACHER	Director	/s/ PAUL L. WHITING PAUL L. WHITING	Director

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

TAMPA ELECTRIC COMPANY

Dated: February 28, 2014

By: /s/ JOHN B. RAMIL
JOHN B. RAMIL
President, Chief Executive Officer and Director
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities indicated on February 28, 2014:

Signature	Title
/s/ JOHN B. RAMIL JOHN B. RAMIL	Chief Executive Officer and Director (Principal Executive Officer)
/s/ SANDRA W. CALLAHAN SANDRA W. CALLAHAN	Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer) (Principal Financial and Principal Accounting Officer)

Signature	Title	Signature	Title
/s/ JAMES L. FERMAN, JR. JAMES L. FERMAN, JR.	Director	/s/ LORETTA A. PENN LORETTA A. PENN	Director
/s/ EVELYN V. FOLLIT EVELYN V. FOLLIT	Director	/s/ TOM L. RANKIN TOM L. RANKIN	Director
/s/ SHERRILL W. HUDSON SHERRILL W. HUDSON	Chairman of the Board and Director	/s/ WILLIAM D. ROCKFORD WILLIAM D. ROCKFORD	Director
/s/ JOSEPH P. LACHER JOSEPH P. LACHER	Director	/s/ PAUL L. WHITING PAUL L. WHITING	Director

Supplemental Information to Be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act

No annual report or proxy material has been sent to Tampa Electric Company's security holders because all of its equity securities are held by TECO Energy, Inc.

INDEX TO EXHIBITS

Exhibit No.	Description	
2.1	Equity Purchase Agreement dated as of September 27, 2012 between TECO Guatemala Holdings II, LLC and Sur Eléctrica Holding Limited (Exhibit 10.1, Form 10-Q, for the quarter ended Sep. 30, 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
2.2	Equity Purchase Agreement dated as of September 27, 2012 between TECO Guatemala Holdings II, LLC and Renewable Energy Investments Guatemala Limited (Exhibit 10.2, Form 10-Q, for the quarter ended Sep. 30, 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
2.3	Equity Purchase Agreement dated as of September 27, 2012 between TECO Guatemala Holdings II, LLC and Renewable Energy Investments Guatemala Limited (Exhibit 10.3, Form 10-Q, for the quarter ended Sep. 30, 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
2.4	Equity Purchase Agreement dated as of October 17, 2012 between TECO Guatemala Holdings II, LLC and C.F. Financeco, Ltd. (Exhibit 2.5, Form 10-K for 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
2.5	Stock Purchase Agreement, dated as of May 25, 2013, by and among TECO Energy, Inc., New Mexico Gas Intermediate, Inc. and Continental Energy Systems LLC (Exhibit 2.1, Form 8-K dated May 28, 2013 of TECO Energy, Inc.).	*
3.1	Amended and Restated Articles of Incorporation of TECO Energy, Inc., as filed on May 3, 2012 (Exhibit 3.1, Form 8-K dated May 4, 2012 of TECO Energy, Inc.).	*
3.2	Bylaws of TECO Energy, Inc., as amended effective May 3, 2012 (Exhibit 3.1, Form 8-K dated May 4, 2011 of TECO Energy, Inc.).	*
3.3	Restated Articles of Incorporation of Tampa Electric Company, as amended on Nov. 30, 1982 (Exhibit 3 to Registration Statement No. 2-70653 of Tampa Electric Company).	*
3.4	Bylaws of Tampa Electric Company, as amended effective Feb. 2, 2011 (Exhibit 3.4, Form 10-K for 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
4.1	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company of Florida, N.A., as trustee, dated as of Jun. 1, 2002 (including the form of bond) (Exhibit 4.5, Amendment No. 1 to Form 10-K for 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
4.2	Loan and Trust Agreement among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee, dated as of Jan. 5, 2006 (including the form of bond) (Exhibit 4.1, Form 8-K dated Jan. 19, 2006 of Tampa Electric Company).	*
4.3	Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Jul. 1, 1998 (Exhibit 4.1, Registration Statement No. 333-55873 of Tampa Electric Company).	*
4.4	Third Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Jun. 15, 2001 (Exhibit 4.2, Form 8-K dated Jun. 25, 2001 of Tampa Electric Company).	*
4.5	Fourth Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of Aug. 15, 2002 (Exhibit 4.2, Form 8-K dated Aug. 26, 2002 of Tampa Electric Company).	*
4.6	Fifth Supplemental Indenture between Tampa Electric Company and The Bank of New York, as trustee, dated as of May 1, 2006 (Exhibit 4.16, Form 8-K dated May 12, 2006 of Tampa Electric Company).	*
4.7	Amended and Restated Note Agreement dated as of May 30, 1997 between Tampa Electric Company (successor by merger to Peoples Gas System, Inc.) and The Prudential Insurance Company of America (Exhibit 4.2, Form 8-K dated Dec. 15, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
4.8	Letter Amendment No. 1 dated as of Dec. 9, 2004 to the Amended and Restated Note Agreement dated as of May 30, 1997 between Tampa Electric Company (successor by merger to Peoples Gas System, Inc.) and The Prudential Insurance Company of America (Exhibit 4.1, Form 8-K dated Dec. 15, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
4.9	Note Purchase Agreement among Tampa Electric Company and the Purchasers party thereto, dated as of Apr. 11, 2003 (Exhibit 10.1, Form 8-K dated Apr. 14, 2003 of Tampa Electric Company).	*
4.10	Loan and Trust Agreement dated as of November 15, 2010 among Tampa Electric Company, Polk County Industrial Development Authority and The Bank of New York Mellon Trust Company, N.A., as trustee (including the form of bond) (Exhibit 4.1, Form 8-K dated Nov. 23, 2010 of Tampa	*

	Electric Company).	
4.11	Sixth Supplemental Indenture dated as of May 1, 2007 between Tampa Electric Company and The Bank of New York, as trustee (Exhibit 4.18, Form 8-K dated May 25, 2007 of Tampa Electric Company).	*
4.12	Seventh Supplemental Indenture dated as of May 1, 2008 between Tampa Electric Company and The Bank of New York, as trustee (Exhibit 4.20, Form 8-K dated May 16, 2008 of Tampa Electric Company).	*
4.13	Eighth Supplemental Indenture dated as of Nov. 15, 2010 between Tampa Electric Company, as issuer, and The Bank of New York Mellon, as trustee (including the form of 5.40% Notes due 2021) (Exhibit 4.1, Form 8-K dated Dec. 9, 2010 of Tampa Electric Company).	*
4.14	Ninth Supplemental Indenture dated as of May 31, 2012 between Tampa Electric Company, as issuer, and The Bank of New York Mellon, as trustee, supplementing the Indenture dated as of July 1, 1998, as amended (including the form of 4.10% Notes due 2042) (Exhibit 4.23, Form 8-K dated June 5, 2012 for Tampa Electric Company).	*
4.15	Tenth Supplemental Indenture dated as of September 19, 2012 between Tampa Electric Company, as issuer, and The Bank of New York Mellon, as trustee, supplementing and amending the Indenture dated as of July 1, 1998, as amended (including the form of 2.60% Notes due 2022) (Exhibit 4.25, Form 8-K dated September 28, 2012 for Tampa Electric Company).	*
4.16	Loan and Trust Agreement dated as of Jul. 2, 2007 among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee (including the form of Bond) (Exhibit 4.1, Form 8-K dated Jul. 25, 2007 of Tampa Electric Company).	*
4.17	First Supplemental Loan and Trust Agreement dated as of Mar. 26, 2008 among Hillsborough County Industrial Development Authority, Tampa Electric Company and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1, Form 8-K dated Mar. 26, 2008 of Tampa Electric Company).	*
4.18	Indenture between TECO Energy, Inc. and The Bank of New York, as trustee, dated as of Aug. 17, 1998 (Exhibit 4.1, Form 8-K dated Sep. 20, 2000 of TECO Energy, Inc.).	*
4.19	Third Supplemental Indenture dated as of Dec. 1, 2000 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.21, Form 8-K dated Dec. 20, 2000 of TECO Energy, Inc.).	*
4.20	Fourth Supplemental Indenture dated as of Apr. 30, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.28, Form 8-K dated May 1, 2001 of TECO Energy, Inc.).	*
4.21	Fifth Supplemental Indenture dated as of Sep. 10, 2001 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.16, Form 8-K dated Sep. 26, 2001 of TECO Energy, Inc.).	*
4.22	Seventh Supplemental Indenture dated as of May 1, 2002 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated May 13, 2002 of TECO Energy, Inc.).	*
4.23	Ninth Supplemental Indenture dated as of Jun. 10, 2003 between TECO Energy, Inc. and The Bank of New York, as trustee (Exhibit 4.15, Form 8-K dated Jun. 13, 2003 of TECO Energy, Inc.).	*
4.24	Tenth Supplemental Indenture dated as of May 26, 2005 between TECO Energy, Inc. and The Bank of New York, as trustee (including the form of 6.75% Note) (Exhibit 4.1, Form 8-K dated May 26, 2005 of TECO Energy, Inc.).	*
4.25	Eleventh Supplemental Indenture dated as of Jun. 7, 2005 between TECO Energy, Inc. and The Bank of New York, as trustee (including the form of Floating Rate Note) (Exhibit 4.1, Form 8-K dated Jun. 7, 2005 of TECO Energy, Inc.).	*
4.26	Indenture dated as of Dec. 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee (Exhibit 4.1, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*
4.27	First Supplemental Indenture dated as of Dec. 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee (including the form of TECO Finance 7.20% Notes due 2011, TECO Finance 7.00% Notes due 2012 and TECO Finance 6.572% Notes due 2017) (Exhibit 4.2, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*
4.28	Second Supplemental Indenture dated as of Dec. 21, 2007 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Trust Company, N.A., as trustee (including the form of TECO Finance 6.75% Notes due 2015) (Exhibit 4.3, Form 8-K dated Dec. 21, 2007 of TECO Energy, Inc.).	*
4.29	Third Supplemental Indenture dated as of Mar. 15, 2010 by and among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee (including the form of TECO Finance 4.00% Notes due 2016 and 5.15% Notes due 2020) (Exhibit 4.26, Form 8-K dated Mar. 15, 2010 of TECO Energy, Inc.).	*
4.30	Twentieth Supplemental Indenture dated as of December 1, 2013 between Tampa Electric Company	

	and US Bank, N.A., as successor trustee, to the Indenture of Mortgage among Tampa Electric Company, State Street Trust Company and First Savings & Trust Company of Tampa, dated as of Aug. 1, 1946.	
10.1	TECO Energy Group Supplemental Executive Retirement Plan, as amended and restated as of Nov. 1, 2007 (Exhibit 10.1, Form 10-K for 2007 of TECO Energy, Inc. and Tampa Electric Company).	*
10.2	TECO Energy Group Supplemental Disability Income Plan, dated as of Mar. 20, 1989 (Exhibit 10.22, Form 10-K for 1988 of TECO Energy, Inc.).	*
10.3	TECO Energy Group Supplemental Retirement Benefits Trust Agreement, effective as of Nov. 17, 2008 (Exhibit 10.3, Form 10-K for 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.4	Annual Incentive Compensation Plan for TECO Energy and subsidiaries, revised as of Feb. 2, 2011 (Exhibit 10.4, Form 10-K for 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.5	Form of Change-in-Control Severance Agreement between TECO Energy, Inc. and certain Executive Officers (Exhibit 10.1, Form 10-Q for the quarter ended Sep. 30, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.6	Form of Change-in-Control Severance Agreement between TECO Energy, Inc. and certain Executive Officers (Exhibit 10.1, Form 8-K dated Feb. 5, 2010 of TECO Energy, Inc.).	*
10.7	TECO Energy Directors' Deferred Compensation Plan, as amended and restated effective as of Aug. 1, 2007 (Exhibit 10.3, Form 10-Q for the quarter ended Sep. 30, 2007 of TECO Energy, Inc. and Tampa Electric Company).	*
10.8	Amendment No. 1 to TECO Energy Directors' Deferred Compensation Plan, effective as of Apr. 29, 2009 (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.9	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1996 Equity Incentive Plan (and its successor plan) (Exhibit 10.5, Form 10-Q for the quarter ended Jun. 30, 1999 of TECO Energy, Inc.).	*
10.10	TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.1, Form 8-K dated Apr. 16, 1997 of TECO Energy, Inc.).	*
10.11	Form of Nonstatutory Stock Option under the TECO Energy, Inc. 1997 Director Equity Plan, dated as of Jan. 29, 2003 (Exhibit 10.28, Form 10-K for 2002 of TECO Energy, Inc. and Tampa Electric Company).	*
10.12	TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
10.13	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Jun. 30, 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.14	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended Jun. 30, 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.15	Nonstatutory Stock Option granted to S. W. Hudson, dated as of Jul. 6, 2004, under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended Jun. 30, 2004 of TECO Energy, Inc. and Tampa Electric Company).	*
10.16	TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.1, Post-Effective Amendment No. 1 to Form S-8 Registration Statement No. 333-115954 dated May 5, 2010 of TECO Energy, Inc.).	*
10.17	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.2, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.18	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.3, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.19	Form of Restricted Stock Agreement between TECO Energy, Inc. and certain directors under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.4, Form 10-Q for the quarter ended Jun. 30, 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.20	Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended March 31, 2013).	*
10.21	Compensatory Arrangements with Executive Officers of TECO Energy, Inc.	
10.22	Compensatory Arrangements with Non-Management Directors of TECO Energy, Inc.	
10.23	Employment Agreement between TECO Energy, Inc. and Sherrill W. Hudson dated Aug. 4, 2010 (Exhibit 10.1, Form 8-K dated Aug. 4, 2010 of TECO Energy, Inc.).	*
10.24	Change-in-Control Severance Agreement between TECO Energy, Inc. and Clark Taylor	*

	(Exhibit 10.1, Form 10-Q for the quarter ended Mar. 31, 2011 of TECO Energy, Inc. and Tampa Electric Company).	
10.25	Change-in-Control Severance Agreement between TECO Coal Corporation and Clark Taylor (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.26	Insurance Agreement dated as of Jan. 5, 2006 between Tampa Electric Company and Ambac Assurance Corporation (Exhibit 10.1, Form 8-K dated Jan. 19, 2006 of Tampa Electric Company).	*
10.27	Third Amended and Restated Credit Agreement dated as of Oct. 25, 2011, among TECO Finance, Inc., as Borrower, TECO Energy, Inc. as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 4.1, Form 8-K dated Oct. 25, 2011 of TECO Energy, Inc.).	*
10.28	Third Amended and Restated Credit Agreement dated as of Oct. 25, 2011, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 4.2, Form 8-K dated Oct. 25, 2011 of Tampa Electric Company).	*
10.29	Purchase and Contribution Agreement dated as of Jan. 6, 2005, between Tampa Electric Company as the Originator and TEC Receivables Corporation as the Purchaser (Exhibit 4.1, Form 8-K dated Jan. 6, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
10.30	Loan and Servicing Agreement dated as of Jan. 6, 2005, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 4.2, Form 8-K dated Jan. 6, 2005 of TECO Energy, Inc. and Tampa Electric Company).	*
10.31	Omnibus Amendment No. 3 to Loan and Servicing Agreement dated as of Dec. 22, 2006, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (also amending the agreement identified in Exhibit 10.29 herein) (Exhibit 10.28.1, Form 10-K for 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.32	Amendment No. 6 to Loan and Servicing Agreement dated as of Dec. 18, 2008, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 99.1, Form 8-K dated Dec.18, 2008 of TECO Energy, Inc. and Tampa Electric Company).	*
10.33	Amendment No. 8 to Loan and Servicing Agreement dated as of Feb. 19, 2010, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citicorp North America, Inc. as Program Agent (Exhibit 10.28.3, Form 10-K for 2009 of TECO Energy, Inc. and Tampa Electric Company).	*
10.34	Omnibus Amendment No. 9 to Loan and Servicing Agreement dated as of Feb. 18, 2011, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, North America, Inc. as Program Agent (Exhibit 10.37, Form 10-K for 2010 of TECO Energy, Inc. and Tampa Electric Company).	*
10.35	Amendment No. 10 to Loan and Servicing Agreement dated as of Feb. 17, 2012, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, North America, Inc. as Program Agent (Exhibit 10.38, Form 10-K for 2011 of TECO Energy, Inc. and Tampa Electric Company).	*
10.36	Amendment No. 11 to Loan and Servicing Agreement dated as of Feb. 15, 2013, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, North America, Inc. as Program Agent (Exhibit 10.39, Form 10-K for 2012 of TECO Energy, Inc. and Tampa Electric Company).	*
10.37	Omnibus Amendment No. 12 to Loan and Servicing Agreement dated as of Feb. 14, 2014, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, N. A. Inc. as Program Agent.	
10.38	Commitment Letter, dated as of May 25, 2013, by and among TECO Energy, Inc., TECO Finance, Inc. and Morgan Stanley Senior Funding, Inc. (Exhibit 10.1, Form 8-K dated May 28, 2013 of TECO Energy, Inc.).	*
10.39	Senior Unsecured Bridge Credit Agreement, dated as of June 24, 2013, by and among TECO Energy, Inc., as Guarantor, TECO Finance, Inc., as Borrower, Morgan Stanley Senior Funding, Inc., as Administrative Agent, and the Lenders party thereto (Exhibit 10.1, Form 8-K dated June 28, 2013 of TECO Energy, Inc.).	*
10.40	Amendment No. 1 dated as of June 24, 2013 to the Third Amended and Restated Credit Agreement dated as of October 25, 2011, among TECO Finance, Inc., as Borrower, TECO Energy, Inc. as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.2, Form 8-K dated June 28, 2013 of TECO Energy, Inc.).	*

10.41	Fourth Amended and Restated Credit Agreement dated as of December 17, 2013, among TECO Finance, Inc., as Borrower, TECO Energy, Inc. as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 10.1, Form 8-K dated Dec. 17, 2013 of TECO Energy, Inc. and Tampa Electric Company).	*
10.42	Fourth Amended and Restated Credit Agreement dated as of December 17, 2013, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 10.2, Form 8-K dated Dec. 17, 2013 of TECO Energy, Inc. and Tampa Electric Company).	*
10.43	Credit Agreement dated as of December 17, 2013, among TECO Energy, Inc., as Initial Borrower JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders and LC Issuing Banks party thereto (Exhibit 10.3, Form 8-K dated Dec. 17, 2013 of TECO Energy, Inc. and Tampa Electric Company).	*
12.1	Ratio of Earnings to Fixed Charges – TECO Energy, Inc.	
12.2	Ratio of Earnings to Fixed Charges – Tampa Electric Company.	
21	Subsidiaries of TECO Energy, Inc.	
23.1	Consent of Independent Certified Public Accountants – TECO Energy, Inc.	
23.2	Consent of Independent Certified Public Accountants – Tampa Electric Company.	.
23.3	Consent of Cardno MM&A.	.
31.1	Certification of the Chief Executive Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.2	Certification of the Chief Financial Officer of TECO Energy, Inc. pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.3	Certification of the Chief Executive Officer of Tampa Electric Company pursuant to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
31.4	Certification of the Chief Financial Officer of Tampa Electric Company to Securities Exchange Act Rules 13a-14(a) and 15d-14(a) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
32.1	Certification of the Chief Executive Officer and Chief Financial Officer of TECO Energy, Inc. pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)	
32.2	Certification of the Chief Executive Officer and Chief Financial Officer of Tampa Electric Company pursuant to 18 U.S.C. Section 1350 as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. (1)	
95	Mine Safety Disclosure	
101.INS	XBRL Instance Document	
101.SCH	XBRL Taxonomy Extension Schema Document	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document	
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document	
101.LAB	XBRL Taxonomy Extension Label Linkbase Document	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document	

(1) This certification accompanies the Annual Report on Form 10-K and is not filed as part of it.
* Indicates exhibit previously filed with the Securities and Exchange Commission and incorporated herein by reference. Exhibits filed with periodic reports of TECO Energy, Inc. and Tampa Electric Company were filed under Commission File Nos. 1-8180 and 1-5007, respectively.

Certain instruments defining the rights of holders of long-term debt of TECO Energy, Inc. and its consolidated subsidiaries authorizing in each case a total amount of securities not exceeding 10% of total assets on a consolidated basis are not filed herewith. TECO Energy, Inc. will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Certain instruments defining the rights of holders of long-term debt of Tampa Electric Company authorizing in each case a total amount of securities not exceeding 10% of total assets on a consolidated basis are not filed herewith. Tampa Electric Company will furnish copies of such instruments to the Securities and Exchange Commission upon request.

Executive Compensation Plans and Arrangements

Exhibits 10.1 through 10.25, above are management contracts or compensatory plans or arrangements in which executive officers or directors of TECO Energy, Inc. participate.