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September 1, 2016

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, Florida Statutes, and Chapter 25-8, Florida Administrative Code.

Dear Ms. Stauffer:

Attached for filing in the above-styled matter is Tampa Electric Company's Application for Authority to Issue and Sell Securities for the fiscal period of 12 months ending December 31, 2017.

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, Florida Statutes and Chapter 25-8, Florida Administrative Code | ) | DOCKET NO. ____________<br>Submitted for filing on September 1, 2016 |

**TAMPA ELECTRIC COMPANY'S**

**APPLICATION FOR AUTHORITY TO ISSUE AND SELL SECURITIES**

Tampa Electric Company ("the Company") files this, its Application under Section 366.04, Florida Statues and Rule 25-8.001, et seq., Florida Administrative Code, for authority to issue and/or sell securities for the Company's fiscal period of 12 months ending December 31, 2017 and says:

1. The exact name of the Company and the address of its principal business office are as follows: Tampa Electric Company, 702 North Franklin Street, Tampa, Florida, 33602.

2. The Company, a Florida corporation, was incorporated in 1899 and was reincorporated in 1949. The Company provides Commission-regulated retail electric services and natural gas distribution services through its Tampa Electric and Peoples Gas System divisions, respectively.

3. The names and addresses of persons authorized to receive notices and communications with respect to this Application are as follows:


James D. Beasley
jbeasley@ausley.com
J. Jeffry Wahlen
jwahlen@ausley.com
Ausley & McMullen
P. O. Box 391
Tallahassee, FL 32302
(850) 224-9115

Paula K. Brown
regdept@tecoenergy.com
Manager, Regulatory Coordination
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601
(813) 228-1444

4. As of June 30, 2016, the date of the balance sheet submitted with this Application, the following information is shown for each class and series of capital stock and funded debt:

| (a) Brief description | (b) Amount authorized (face value and number of shares) | (c) Amount outstanding (exclusive of any amount held in the treasury) | (d) Amount held as reacquired securities | (e) Pledged by applicant | (f) Amount owned by affiliated corporations | (g) Amount held in any fund |
|---|---|---|---|---|---|---|
| **Common Stock** | 25,000,000 shares, without par value | 10 shares | None | None | 10 shares | None |
| **Preferred Stock** | 2,500,000 shares with no par value, 1,500,000 shares with $100 par value per share | None | None | None | None | None |
| **Preference Stock - Subordinated Preferred Stock** | 2,500,000 shares, with no par value | None | None | None | None | None |
| | | | | | | |
| **Funded Debt:** | | | | | | |
| | | | | | | |
| **Tampa Electric division** | | | | | | |
| | | | | | | |
| Installment Contracts Payable: | | | | | | |
| 5.15% Series, due 2025 | $51,600,000 | None | $51,600,000 | None | None | None |
| 5.65% Series, due 2018 | 54,200,000 | $54,200,000 | None | None | None | None |
| Variable Interest Series, due 2020 | 20,000,000 | None | 20,000,000 | None | None | None |
| 5% Series, due 2034 | 85,950,000 | None | 85,950,000 | None | None | None |
| Variable Interest Series, due 2030 | 75,000,000 | None | 75,000,000 | None | None | None |
| | | | | | | |
| Unsecured Notes: | | | | | | |
| 6.10% Series, due 2018 | 200,000,000 | 200,000,000 | None | None | None | None |
| 5.40% Series, due 2021 | 231,730,320 | 231,730,320 | None | None | None | None |
| 2.60% Series, due 2022 | 225,000,000 | 225,000,000 | None | None | None | None |
| 6.55% Series, due 2036 | 250,000,000 | 250,000,000 | None | None | None | None |
| 6.15% Series, due 2037 | 190,000,000 | 190,000,000 | None | None | None | None |
| 4.10% Series, due 2042 | 250,000,000 | 250,000,000 | None | None | None | None |
| 4.35% Series, due 2044 | 290,000,000 | 290,000,000 | None | None | None | None |
| 4.20% Series, due 2045 | 230,000,000 | 230,000,000 | None | None | None | None |
| | | | | | | |
| **Peoples Gas System division** | | | | | | |
| | | | | | | |
| Unsecured Notes: | | | | | | |
| 6.10% Series, due 2018 | 50,000,000 | 50,000,000 | None | None | None | None |
| 5.40% Series, due 2021 | 46,764,680 | 46,764,680 | None | None | None | None |
| 2.60% Series, due 2022 | 25,000,000 | 25,000,000 | None | None | None | None |
| 6.15% Series, due 2037 | 60,000,000 | 60,000,000 | None | None | None | None |
| 4.10% Series, due 2042 | 50,000,000 | 50,000,000 | None | None | None | None |
| 4.35% Series, due 2044 | 10,000,000 | 10,000,000 | None | None | None | None |
| 4.20% Series, due 2045 | 20,000,000 | 20,000,000 | None | None | None | None |
| | | | | | | |
| Total Funded Debt | $2,415,245,000 | $2,182,695,000 | $232,550,000 | | | |
| | | | | | | |

5. Statement of Proposed Transactions

(a) The Company seeks the authority to issue, sell and/or exchange equity securities and issue, sell, exchange and/or assume long-term or short-term debt securities and/or to assume liabilities or obligations as guarantor, endorser or surety during the period covered by this Application. The Company also seeks authority to enter into interest rate swaps or other derivative instruments related to debt securities. Any exercise of the requested authority will be for the benefit of the Company. In connection with this application, the Company confirms that the capital raised pursuant to this application will be used in connection with the activities of the Company's regulated electric and gas divisions and not the unregulated activities of the utilities or their affiliates.

The equity securities may take the form of preferred stock, preference stock, common stock, or options or rights with respect to the foregoing with such par values, terms and conditions, conversion and relative rights and preferences as may be permitted by the Company's Restated Articles of Incorporation, as the same may be amended to permit the issuance of any such securities. The long-term debt securities may take the form of first mortgage bonds, debentures, notes, bank borrowings, convertible securities, installment contracts and/or other obligations underlying pollution control or sewage and solid waste disposal revenue bonds or options, rights, interest rate swaps or other derivative instruments with respect to the foregoing, with maturities ranging from one to 100 years, and may be issued in both domestic and international markets.

The issuance and/or sale of equity securities and long-term debt requested may be through negotiated underwritten public offering, public offering at competitive bidding, direct public or private sale, sale through agents, or distribution to security holders of the Company or affiliated companies.

The short-term debt may take the form of commercial paper, short-term tax-exempt notes, borrowings under bank credit facilities or accounts receivable securitization credit facilities, or other bank borrowings. Short-term debt sold in the commercial paper market may bear an interest rate as determined by the market price at the date of issuance and will mature not more than one year from the date of issuance.

(b) The amount of all equity and long-term debt securities issued, sold, exchanged or assumed and liabilities and obligations assumed or guaranteed as guarantor, endorser, or surety will not exceed in the aggregate $1.2 billion during the period covered by this Application, including any amounts issued to retire existing long-term debt securities. The maximum amount of short-term debt, as described above, outstanding at any one time, will be $0.9 billion.

(c) With respect to equity and long-term debt securities and liabilities and obligations to be assumed or guaranteed as grantor, endorser or surety, the amount of $200 million is needed to accommodate the potential issuance of additional notes based on projected short-term debt levels and debt maturities; the amount of $200 million is needed for potential long-term emergency funding; and the amount of $800 million is needed for other purposes (swaps, refinancings, etc.). With respect to short-term debt, the amount of up to $700 million outstanding is needed to enable the Company to fully draw existing short-term credit facilities including upsize capability; and the balance of up to $200 million is needed to avail the Company of short-term emergency funding and other purposes.

(d) The present estimates of the interest rates for the aforementioned debt securities, based upon current trading levels of unsecured short-term debt and 10-year notes of the Company are 1.15% and 2.75%, respectively. Actual dividend rates for the aforementioned equity securities and interest rates will be determined at the time of the issuance and/or sale of the applicable securities.

6. Purpose of Issuance

Proceeds from any sale of securities will be added to the Company’s general funds and used for working capital requirements and for other general business purposes, including financing of the Company's capital investments or the acquisition of additional properties or businesses. The net proceeds received from the sale of securities may also be used for the repurchase or repayment of debt or equity securities of the Company.

(a) Construction

The electric division of the Company currently estimates that construction expenditures during the 12 months ending December 31, 2017 will be $318 million. Capital requirements for major generating plants and transmission lines requiring certification of needs includes:

| Projects (Millions) | Actual Capital to date | 2017 Amount |
|---|---|---|
| Polk 2-5 Conversion | | |
| Generation | $444 | $6 |
| Transmission & Distribution | 114 | 0 |
| Total | $ 558 | $ 6 |

The gas division of the Company currently estimates that construction expenditures during the 12 months ending December 31, 2017 will be $130 million for maintenance and system expansion.

(b) Reimbursement of the Treasury

Among the general business purposes for which any net proceeds may be used is the reimbursement of the treasury for expenditures by the Company against which securities will not have been issued in advance.

(c) Refunding Obligations

One of the purposes of issuing the securities referred to herein will be to repay previously issued short-term debt, of the type described in paragraph 5, which matures from time to time on a regular basis. Subject to market conditions, the Company may refund such short-term debt with new short-term debt, long-term debt or preferred or preference stock.

In addition, the Company is continuing to monitor and evaluate market conditions in anticipation of refunding or refinancing long-term obligations where it is legally and economically feasible to do so. Recognizing that changes in market conditions could make such refunding transactions feasible, the Company is requesting authority to issue long-term debt and/or preferred or preference stock within a limitation that provides the Company with sufficient flexibility to respond to refunding or refinancing opportunities.

7. The Company submits that the proposed issuance and sale of securities is for lawful objectives within the corporate purposes of the Company, is necessary for the proper performance by the two divisions of the Company as public utilities, is compatible with the public interest and is reasonable, necessary and appropriate. In support thereof the Company states that the proposed issuance and sale of securities and the proposed application of funds derived therefrom, as described in paragraphs 5 and 6 above, are consistent with similar actions the Company in the past has found to be lawful, reasonable, necessary and appropriate for the conduct of its business. The Company further states that this application for authority to issue and sell securities is consistent in its objectives with those of applications the Company has filed, and this Commission has found to be lawful, reasonable, necessary and appropriate, on numerous occasions in the past.

8. The names and addresses of counsel who will pass upon the legality of the proposed issuances are: David M. Nicholson, General Counsel, Tampa Electric Company, Tampa, Florida; David E. Schwartz, Associate General Counsel, Tampa Electric Company, Tampa, Florida; Holland & Knight LLP, Tampa, Florida; and/or Lock Lorde LLP, Boston, Massachusetts and/or such other counsel as the Company may deem necessary in connection with any of the proposed issuances.

9. A Registration Statement with respect to each public offering of securities hereunder that is subject to and not exempt from the registration requirements of the Securities Act of 1933, as amended, will be filed with the Securities and Exchange Commission, 100 F St. N.E., Washington, D.C. 20549.

10. There is no measure of control or ownership exercised by or over the Company as to any other public utility except as noted below.

On April 14, 1981, the Company's shareholders approved a restructuring plan under which the Company and its subsidiaries became separate wholly owned subsidiaries of a holding company, TECO Energy, Inc.

**Required Exhibits**

1. The following exhibits required by Rule 25-8.003, Florida Administrative Code, are either attached hereto or incorporated by reference herein and made a part hereof:

   (a) Exhibit A: Items 1 through 5 are being satisfied through the provision of financial statements identified in Item 6 below.

   6. (i) Attached as Exhibit A-1 (2015 Form 10-K)
      (ii) Attached as Exhibit A-2 (Most Recent Quarterly 2016 Form 10-Q)

   (b) Exhibit B: Projected Financial Information (Sources and Uses of Funds Statements and Construction Budgets)

**WHEREFORE,** Tampa Electric Company respectfully requests that the Commission enter its Order approving the Company's request for authority to issue and sell securities during the 12-month period ending December 31, 2017.

**DATED** this 1st day of September, 2016

**TAMPA ELECTRIC COMPANY**

By: KM Caruso
Kim M. Caruso
Managing Director - Finance

**TAMPA ELECTRIC COMPANY'S**
**APPLICATION FOR AUTHORITY TO ISSUE AND SELL SECURITIES**

## INDEX TO EXHIBITS

# Exhibit A-1

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

# FORM 10-K

☒ **Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**

**For the fiscal year ended December 31, 2015**

**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.**<br>(a Florida corporation)<br>TECO Plaza<br>702 N. Franklin Street<br>Tampa, Florida 33602<br>(813) 228-1111 | **59-2052286** |
| **1-5007** | **TAMPA ELECTRIC COMPANY**<br>(a Florida corporation)<br>TECO Plaza<br>702 N. Franklin Street<br>Tampa, Florida 33602<br>(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.<br>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 ☒ 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 ☒

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 ☒

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 ☒ 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 ☒ 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. ☐

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 | ☒ | 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 | ☒ | 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 ☒

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

YES ☐ NO ☒

The aggregate market value of TECO Energy, Inc.'s common stock held by non-affiliates of the registrant as of June 30, 2015 was approximately $4.10 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 30, 2015 was zero.

The number of shares of TECO Energy, Inc.'s common stock outstanding as of Feb. 12, 2016 was 235,494,800. As of Feb. 12, 2016, 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.

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.

## 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 |
| 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 |
| CAIR | Clean Air Interstate Rule |
| Cambrian | Cambrian Coal Corporation |
| capacity clause | capacity cost-recovery clause, as established by the FPSC |
| CCRs | coal combustion residuals |
| CES | Continental Energy Systems |
| CMO | collateralized mortgage obligation |
| CNG | compressed natural gas |
| company | TECO Energy, Inc. |
| CPI | consumer price index |
| CSAPR | Cross State Air Pollution Rule |
| $CO_2$ | carbon dioxide |
| CT | combustion turbine |
| DR-CAFTA | Dominican Republic Central America – United States Free Trade Agreement |
| ECRC | environmental cost recovery clause |
| EEI | Edison Electric Institute |
| EGWP | Employee Group Waiver Plan |
| Emera | Emera Inc., a geographically diverse energy and services company headquartered in Nova Scotia, Canada |
| EPA | U.S. Environmental Protection Agency |
| EPS | earnings per share |
| ERISA | Employee Retirement Income Security Act |
| EROA | expected return on plan assets |
| 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 |
| GCBF | gas cost billing factor |
| GHG | greenhouse gas(es) |
| HAFTA | Highway and Transportation Funding Act |
| HCIDA | Hillsborough County Industrial Development Authority |
| ICSID | International Centre for the Settlement of Investment Disputes |
| IGCC | integrated gasification combined-cycle |
| IOU | investor owned utility |
| IRS | Internal Revenue Service |
| ISDA | International Swaps and Derivatives Association |
| 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 | the section of this report entitled Management's Discussion and Analysis of Financial Condition and Results of Operations |
| Merger | Merger of Merger Sub with and into TECO Energy, with TECO Energy as the surviving corporation |
| Merger Agreement | Agreement and Plan of Merger dated Sept. 4, 2015, by and among TECO Energy, Emera and Merger Sub |
| Merger Sub | Emera US Inc., a Florida corporation |
| MMA | The Medicare Prescription Drug, Improvement and Modernization Act of 2003 |

| **Term** | **Meaning** |
|---|---|
| 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 |
| NMGC | New Mexico Gas Company, Inc. |
| 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 |
| OCI | other comprehensive income |
| OPEB | other postretirement benefits |
| OTC | over-the-counter |
| Parent | TECO Energy (the holding company, excluding subsidiaries) |
| PBGC | Pension Benefit Guarantee Corporation |
| PBO | postretirement benefit obligation |
| PCI | pulverized coal injection |
| PGA | purchased gas adjustment |
| PGAC | purchased gas adjustment clause |
| PGS | Peoples Gas System, the gas division of Tampa Electric Company |
| PPA | power purchase agreement |
| PPSA | Power Plant Siting Act |
| PRP | potentially responsible party |
| REIT | real estate investment trust |
| RFP | request for proposal |
| ROE | return on common equity |
| Regulatory ROE | return on common equity as determined for regulatory purposes |
| ROW | rights-of-way |
| 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 | Securities Purchase Agreement dated Sept. 21, 2015, by and between TECO Diversified and Cambrian relating to the purchase of TECO Coal by Cambrian |
| 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 Coal | TECO Coal LLC, and its subsidiaries, a coal producing subsidiary of TECO Diversified |
| TECO Diversified | TECO Diversified, Inc., a subsidiary of TECO Energy, Inc. and parent of TECO Coal Corporation |
| TECO Energy | TECO Energy, Inc. |
| 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 |
| TGH | TECO Guatemala Holdings, LLC |
| TRC | TEC Receivables Company |
| TSI | TECO Services, Inc. |
| U.S. GAAP | generally accepted accounting principles in the United States |
| VIE | variable interest entity |
| WRERA | The Worker, Retiree and Employer Recovery Act of 2008 |

# PART I

## Item 1. BUSINESS.

## TECO ENERGY

TECO Energy, Inc. was incorporated in Florida in 1981 as part of a restructuring in which it became the parent corporation of Tampa Electric Company. 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, NMGI, owns NMGC. TECO Energy and its subsidiaries had approximately 3,713 employees as of Dec. 31, 2015.

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. The public may read and copy any reports or other information that the company files with the SEC at the SEC's public reference room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

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 719,000 customers in West Central Florida with a net winter system generating capacity of 4,730 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 approximately 361,000 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 2015 was approximately 1.8 billion therms.

NMGC, a Delaware corporation and wholly owned subsidiary of NMGI, was acquired by the company on Sept. 2, 2014. NMGC is engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in New Mexico. With more than 516,000 customers, NMGC serves approximately 60% of the state's population in 23 of New Mexico's 33 counties. NMGC's largest concentration of customers (approximately 360,000) is in the region known as the Central Rio Grande Corridor, which includes the communities of Albuquerque, Belen, Rio Rancho and Santa Fe. NMGC's 2014 results are included as of the acquisition date (see **Note 21** to the **TECO Energy Consolidated Financial Statements** for additional information).

### Revenues from Continuing Operations

| *(millions)* | *2015* | *2014* | *2013* |
|---|---|---|---|
| Tampa Electric | $ 2,018.3 | $ 2,021.0 | $ 1,950.5 |
| PGS | 407.5 | 399.6 | 393.5 |
| NMGC | 316.5 | 137.5 | 0.0 |
| Total regulated businesses | 2,742.3 | 2,558.1 | 2,344.0 |
| Other | 1.2 | 8.3 | 11.1 |
| Total revenues from continuing operations | $ 2,743.5 | $ 2,566.4 | $ 2,355.1 |

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

### Pending Merger with Emera

On Sept. 4, 2015, TECO Energy and Emera entered into the Merger Agreement. Upon closing, which is expected to occur in the summer of 2016, TECO Energy will become a wholly owned indirect subsidiary of Emera. Pursuant to the Merger Agreement, upon the closing of the Merger, each issued and outstanding share of TECO Energy common stock will be cancelled and converted automatically into the right to receive $27.55 in cash, without interest. This represents an aggregate purchase price of approximately $10.4 billion including assumption of approximately $3.9 billion of debt. See **Note 21** to the **TECO Energy Consolidated Financial Statements** for further information regarding the pending Merger.

**Acquisition of NMGI**

On Sept. 2, 2014, the company completed the acquisition contemplated by the acquisition agreement dated May 25, 2013 by and among the company, NMGI and Continental Energy Systems LLC. As a result of that acquisition, the company acquired all of the capital stock of NMGI. NMGI, which was incorporated in the State of Delaware in 2008, is the parent company of NMGC. The aggregate purchase price was $950 million, which included the assumption of $200 million of senior secured notes at NMGC, plus certain working capital adjustments. See **Note 21** to the **TECO Energy Consolidated Financial Statements** for more information regarding the acquisition.

**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 completed the sale of its generating and transmission assets in Guatemala during 2012 as part of a business strategy to focus on its domestic electric and gas utilities. While TECO Energy and its subsidiaries no longer have assets or operations in Guatemala, TECO Guatemala Holdings, a wholly owned subsidiary of TECO Energy, has retained its rights under an arbitration claim against the Republic of Guatemala under the DR-CAFTA.

On Sept. 21, 2015, TECO Diversified entered into an agreement and completed the sale of all of its ownership interest in TECO Coal to Cambrian. TECO Coal, a Kentucky LLC and formerly wholly owned subsidiary of TECO Diversified, had subsidiaries which owned assets in Eastern Kentucky, Tennessee and Virginia. These entities owned mineral rights, owned or operated surface and underground mines and owned interests in coal processing and loading facilities.

See **Notes 12** and **19** to the **TECO Energy Consolidated Financial Statements** for more information regarding these discontinued operations and asset dispositions.

**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. 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 two electric generating stations in or near Tampa and one electric generating station in southwestern Polk County, Florida.

Tampa Electric had 2,063 employees as of Dec. 31, 2015, of which 844 were represented by the International Brotherhood of Electrical Workers and 164 were represented by the Office and Professional Employees International Union.

In 2015, Tampa Electric's total operating revenue was derived approximately 52% from residential sales, 30% from commercial sales, 8% from industrial sales and 10% from other sales, including bulk power sales for resale. The sources of operating revenue and MWH sales for the years indicated were as follows:

**Operating Revenue**

| *(millions)* | *2015* | *2014* | *2013* |
|---|---|---|---|
| Residential | $ 1,040.3 | $ 1,007.6 | $ 936.8 |
| Commercial | 608.0 | 602.0 | 581.2 |
| Industrial – Phosphate | 53.1 | 59.9 | 71.9 |
| Industrial – Other | 107.1 | 104.6 | 100.4 |
| Other retail sales of electricity | 177.2 | 181.9 | 177.4 |
| Total retail | 1,985.7 | 1,956.0 | 1,867.7 |
| Sales for resale | 3.7 | 13.0 | 8.5 |
| Other | 28.9 | 52.0 | 74.3 |
| Total operating revenues | $ 2,018.3 | $ 2,021.0 | $ 1,950.5 |

**Megawatt- hour Sales**

| *(thousands)* | *2015* | *2014* | *2013* |
|---|---|---|---|
| Residential | 9,045 | 8,656 | 8,470 |
| Commercial | 6,301 | 6,142 | 6,090 |
| Industrial | 1,870 | 1,901 | 2,026 |
| Other retail sales of electricity | 1,791 | 1,827 | 1,832 |
| Total retail | 19,007 | 18,526 | 18,418 |
| Sales for resale | 115 | 259 | 222 |
| Total energy sold | 19,122 | 18,785 | 18,640 |

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 2015, 2014 and the last two months of 2013 reflect the results of a Stipulation and Settlement Agreement entered on Sept. 6, 2013, between Tampa Electric and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric's 2013 base rate proceeding. On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement.

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 Tampa Electric'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 no sooner than Jan. 1, 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 Tampa Electric could seek a review of its base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital, and Tampa Electric also began using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013. Effective Nov. 1, 2013, Tampa Electric ceased accruing $8.0 million annually to the FPSC-approved self-insured storm damage reserve.

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, respectively. Given TECO Energy's acquisition of NMGC, Tampa Electric and TECO Energy jointly requested a waiver from FERC in order for Tampa Electric to continue to supply a de-minimis level of non-power goods and services to its affiliates. TECO Energy separately notified FERC that it would no longer qualify to be considered a single-state holding company under the Public Utility Holding Company Act of 2005 as of Jan. 1, 2015, and thus it had formed a centralized service company, TECO Services, Inc., which would provide other non-power goods and services to Tampa Electric and its affiliates. On Dec. 31, 2014, FERC granted Tampa Electric's requested waiver without conditions, effective as of Jan. 1, 2015.

On June 30, 2014, the company filed its required triennial market-power analysis in support of the company's continued ability to effect wholesale market-based rate transactions everywhere, except within Tampa Electric's balancing-authority area. FERC accepted Tampa Electric's triennial filing on Nov. 24, 2015.

Tampa Electric is also subject to federal, state and local environmental laws and regulations pertaining to air and 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 of the **MD&A**).

**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 (see the **Environmental Compliance** section of the **MD&A)**. 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.

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 52% of Tampa Electric's generation of electricity for 2015 was natural gas-fired, with coal representing approximately 48%. Tampa Electric used its generating units to meet approximately 94% of the total system load requirements, with the remaining 6% coming from purchased power. Tampa Electric's average delivered fuel cost per MMBTU and average delivered cost per unit of fuel burned have been as follows:

| *Average cost per MMBTU* | *2015* | *2014* | *2013* | *2012* | *2011* |
|---|---|---|---|---|---|
| Coal [1] | $ 3.34 | $ 3.48 | $ 3.36 | $ 3.57 | $ 3.46 |
| Natural Gas [2] | 4.34 | 5.68 | 5.23 | 5.34 | 6.20 |
| Oil | 22.34 | 0.00 | 24.72 | 23.56 | 21.21 |
| Composite | 3.78 | 4.16 | 4.00 | 4.19 | 4.38 |
| | | | | | |
| Average cost per ton of coal burned | $ 79.76 | $ 83.70 | $ 77.79 | $ 84.59 | $ 83.17 |

(1) Represents the cost of coal and the costs for transportation.
(2) Represents the costs of natural gas, transportation, storage, balancing, hedges for the price of natural gas, and fuel losses for delivery to the energy center.

In 2015, Tampa Electric's generating stations burned fuels as follows: Bayside Station burned natural gas; Big Bend Station, which has $SO_2$ scrubber capabilities and $NO_x$ reduction systems, burned a combination of high-sulfur coal and petroleum coke, No. 2 fuel oil and natural gas; and Polk Power Station burned a blend of low-sulfur coal and petroleum coke (which was gasified and subject to sulfur and particulate matter removal prior to combustion), natural gas and oil.

**Coal**. Tampa Electric burned approximately 4.0 million tons of coal and petroleum coke during 2015 and estimates that its combined coal and petroleum coke consumption will be about 4.1 million tons in 2016. During 2015, Tampa Electric purchased approximately 67% of its coal under long-term contracts with five suppliers, and approximately 33% of its coal and petroleum coke in the spot market. Tampa Electric expects to obtain approximately 85% of its coal and petroleum coke requirements in 2016 under long-term contracts with five suppliers and the remaining 15% in the spot market. Tampa Electric has coal transportation agreements with trucking, rail, barge and ocean vessel companies.

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 2015, approximately 84% of Tampa Electric's coal supply was deep-mined, approximately 7% was surface-mined and the remaining 9% 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, 2015, approximately 63% of Tampa Electric's 1,500,000 MMBTU gas storage capacity was full. Tampa Electric has contracted for 78% of its expected gas needs for the April 2016 through October 2016 period. In early March 2016, to meet its generation requirements, Tampa Electric expects to issue RFPs to meet its remaining 2016 gas needs and begin contracting for its 2017 gas needs. Additional volume requirements in excess of projected gas needs are purchased on the short-term spot market.

**Oil.** Tampa Electric has an agreement in place to purchase low sulfur No. 2 fuel oil for its Big Bend and Polk Power stations. The agreement has pricing that is 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 caused by non-renewal, Tampa Electric would be able to continue to use public rights-of-way within the municipality based on judicial precedent, 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 ranging from September 2017 through August 2043.

Franchise fees expense totaled $46.5 million in 2015. Franchise fees 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. See **Environmental Compliance** section of the **MD&A** for additional information.

*Capital Expenditures*

Tampa Electric's 2015 capital expenditures included approximately $18 million related to environmental compliance and improvement programs, primarily for electrostatic precipitator and scrubber improvements, SCR catalyst replacements 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 approximately 361,000 customers. The system includes approximately 12,100 miles of mains and 6,900 miles of service lines (see PGS's **Franchises and Other Rights** section below).

PGS had 533 employees as of Dec. 31, 2015. A total of 140 employees in five of PGS's 14 operating divisions and call center are represented by various union organizations.

In 2015, the total throughput for PGS was approximately 1.8 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 60% of PGS's annual therm volume, commercial customers consumed approximately 27%, 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 35% of total revenues.

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 42 compressed natural gas filling stations connected to the PGS distribution system. See the **Outlook** and **PGS Operating Results** sections of the **MD&A** for information on the impact of natural gas vehicles on PGS' operations.

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

| | Revenues | | | Therms | | |
|---|---|---|---|---|---|---|
| *(millions)* | *2015* | *2014* | *2013* | *2015* | *2014* | *2013* |
| Residential | $ 137.0 | $ 144.1 | $ 128.1 | 74.9 | 80.8 | 74.4 |
| Commercial | 138.8 | 139.1 | 133.4 | 470.8 | 460.5 | 438.1 |
| Industrial | 13.0 | 13.1 | 13.4 | 289.0 | 274.3 | 272.0 |
| Off system sales | 49.8 | 39.4 | 56.7 | 166.4 | 84.0 | 143.1 |
| Power generation | 7.2 | 6.8 | 9.9 | 758.3 | 643.5 | 744.4 |
| Other revenues | 50.5 | 48.5 | 42.2 | | | |
| Total | $ 396.3 | $ 391.0 | $ 383.7 | 1,759.4 | 1,543.1 | 1,672.0 |

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 the **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 June 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 2015, the FPSC approved PGS's 2016 PGA cap factor for the period January 2016 through December 2016.

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 pipe removed from its system within seven 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, of the 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 Compliance** section of the **MD&A**).

**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 23,300 transportation-only customers as of Dec. 31, 2015 out of approximately 37,600 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 69 interconnections (gate stations) serving PGS's operating divisions. In addition, PGS's Jacksonville division receives gas delivered by a pipeline company through two gate stations located northwest of Jacksonville. Another pipeline company provides delivery through six gate stations. PGS also has one interconnection with its affiliate pipeline company 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 116 municipalities and districts 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 have various expiration dates ranging from the present through 2044. PGS expects to negotiate twelve franchises in 2016. Franchise fees expense totaled $8.8 million in 2015. Franchise fees 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 and districts 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 **Note 12** to the **TECO Energy Consolidated Financial Statements** and the **Environmental Compliance** section of the **MD&A** for additional information.

*Capital Expenditures*

During the year ended Dec. 31, 2015, PGS did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2016 through 2020 period.

**NEW MEXICO GAS COMPANY**

NMGC is engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in the state of New Mexico. NMGC had approximately 700 employees as of Dec. 31, 2015.

NMGC operates a natural gas distribution system that serves more than 516,000 customers. The system includes approximately 1,600 miles of transmission pipeline, 10,200 miles of mains and 521,400 service lines (see NMGC's **Franchises and Other Rights** section below). NMGC's system interconnects with five interstate pipelines.

For 2015, the total throughput for NMGC was over 775 million therms. Of this total throughput, 52% was gas purchased and resold to retail customers by NMGC, 42% was third-party supplied gas that was delivered for retail transportation-only customers and 6% was gas sold or transported off-system. Industrial and power generation customers consumed approximately 26% of NMGC's 2015 annual therm volume, commercial customers consumed approximately 30%, off-system transportation customers consumed 6% and the remaining balance was consumed by residential customers, which represents approximately 38% of total annual therm volume and 72% of NMGC's total annual revenues.

Revenues and therms for NMGC for the years ended Dec. 31, 2015 and 2014 were as follows:

| | Revenues | | Therms | |
|---|---|---|---|---|
| *(millions)* | *2015* | *2014 (1)* | *2015* | *2014 (1)* |
| Residential | $ 229.2 | $ 281.0 | 291.2 | 284.4 |
| Commercial | 59.6 | 83.0 | 104.4 | 108.9 |
| Industrial | 1.2 | 1.9 | 2.5 | 3.0 |
| Off system sales | 0.3 | 2.2 | 1.2 | 4.2 |
| On system transportation | 19.1 | 19.3 | 328.7 | 329.7 |
| Off system transportation | 0.9 | 0.9 | 47.2 | 47.0 |
| Other revenues | 6.2 | 6.5 | | |
| Total | $ 316.5 | $ 394.8 | 775.2 | 777.2 |

(1) The full period information presented for 2014 is for comparative purposes only, as TECO Energy's ownership began on the acquisition date of Sept. 2, 2014.

No significant part of NMGC'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 NMGC. NMGC's business is seasonal with much higher volumes and revenues experienced during colder winter months.

**Regulation**

The operations of NMGC are regulated by the NMPRC. The NMPRC has jurisdiction over rates, service, issuance of securities, safety, accounting and depreciation practices and other matters. In general, the NMPRC seeks to set rates at a level that provides an opportunity for a utility such as NMGC 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, gas storage services 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 NMGC's weighted cost of capital, primarily includes its cost for long-term debt and an allowed ROE. Base rates are determined in NMPRC revenue requirements proceedings which occur at irregular intervals at the initiative of NMGC, the NMPRC or other parties. For a description of recent proceeding activity, see the **Regulation-NMGC Rates** section of **MD&A**.

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC's base rates by approximately $34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on Jan. 31, 2012, revising, among other things, base rates for all service provided on or after Feb. 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC's base rate revenue by approximately $21.5 million on a normalized annual basis. The monthly residential customer access fee increased from $9.59 to $11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017. In addition, under the order, NMGC provided $2.0 million of pretax credits on customer bills for the first 12-month period post-closing, effective Oct. 1, 2014, and will provide $4.0 million of pretax credits to customers in each subsequent 12-month period until new base rates are effective, as reported in **Note 21** to the **TECO Energy Consolidated Financial Statements**.

NMGC recovers the costs it pays for gas supply and interstate transportation for system supply through the PGAC. This charge is designed to recover the costs incurred by NMGC for purchased gas, gas storage services, interstate pipeline capacity, and other related items associated with the purchase, distribution, and sale of natural gas to its customers. On a monthly basis, NMGC estimates its cost of gas for the next month (taking into consideration the expected cost of gas to be purchased for the next month, expected demand and any prior month under-recovery or over-recovery of NMGC's cost of gas) and sets the GCBF rate to be used in the next month to recover those estimated costs. For any increase or decrease in cost of gas sold, there is a corresponding increase or decrease in revenue collected through the PGAC. NMGC also has regulatory authority to include a simple interest charge or credit based upon the month-end balance of the PGAC under-recovery or over-recovery of NMGC's cost of gas. NMGC's annual PGAC period runs from Sept. 1 to Aug. 31. The NMPRC requires that NMGC file a reconciliation of the PGAC period costs and recoveries, annually in December. Additionally, NMGC must file a PGAC Continuation Filing with the NMPRC every four years. The purpose of the PGAC Continuation Filing is to establish that the continued use of the PGAC is reasonable and necessary. In January 2013, the NMPRC approved the PGAC Continuation Filing allowing for continued use of the PGAC for another four years. NMGC plans to file its next PGAC Continuation Filing in June 2016 for the four-year period ending December 2020.

In addition to its base rates and PGAC, NMGC's residential customers and customers utilizing NMGC's small and medium volume general services also pay a per-therm charge for energy conservation. The conservation charge is intended to permit NMGC to recover, on a dollar-for-dollar basis, prudently incurred expenditures in developing and implementing cost effective energy conservation programs which are approved and monitored by the NMPRC. The NMPRC requires natural gas utilities to offer transportation-only service to all customer classes.

In addition to economic regulation, NMGC is subject to the NMPRC's safety jurisdiction, pursuant to which the NMPRC regulates the construction, operation and maintenance of NMGC's distribution system. In general, the NMPRC 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.

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

Pursuant to New Mexico statutes and NMPRC rules and regulations, NMGC is required to provide transportation-only services for all customer classes. NMGC receives its base rates for distribution gas delivery services regardless of whether a customer decides to opt for transportation-only service or elect NMGC's gas commodity sales service. During the year ended Dec. 31, 2015, NMGC had approximately 4,100 transportation-only end-use customers and approximately 512,000 gas commodity sales service customers. Transportation-only throughput represented 48.5% of total system throughput and 6.3% of total revenue for the year ended Dec. 31, 2015.

Competition for natural gas services 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 transmission and distribution providers and thereby bypassing NMGC transmission and distribution facilities. In response to this competition, NMGC has developed programs, including providing transportation-only services at discounted rates.

**Gas Supplies**

NMGC's service territory is situated between two large natural gas production basins (the San Juan Basin to the northwest of NMGC's service territory and the Permian Basin to the southeast of NMGC's service territory). Natural gas is transported from these production basins on major interstate pipelines to NMGC's intrastate transmission system and then to customers using its distribution system. The San Juan Basin typically supplies 85% of NMGC's gas supply, with the Permian Basin supplying most of the remaining balance. NMGC also sources gas from the Piceance Basin in western Colorado and the Green River Basin in Wyoming.

NMGC's transmission and distribution system interconnects with five interstate pipelines owned by various pipeline companies. NMGC has firm pipeline capacity contracts with these pipeline companies. To enhance gas supply and transportation availability, NMGC has an ownership interest in the Blanco Hub, one of the central supply and marketing points in the San Juan Basin. The Blanco Hub interconnects with NMGC's transmission system as well as major nearby gathering systems and interstate pipelines. To provide for system balancing and peak day supply requirements, NMGC contracts for 3.2 billion cubic feet (Bcf) of underground gas storage capacity and gas storage services in an underground facility in west Texas. This storage facility is connected to two major interstate pipelines that, in turn, connect to NMGC's transmission and distribution system.

Gas is purchased from various suppliers at market pools and processing plant tailgates from marketers and producers. NMGC has negotiated standard terms and conditions for the purchase of natural gas under the NAESB and the Gas Industry Standards Board forms of agreement. NMGC purchases gas for resale to its jurisdictional gas sales customers in accordance with an annual gas supply plan filed with the NMPRC.

Gas price spikes, which can occur in high demand winter months, have the potential to significantly increase customer bills. To provide a degree of price protection, NMGC utilizes a hedging plan for a portion of the winter gas supply. The gas hedging activity is discussed in more detail in **Note 16** of the **TECO Energy Consolidated Financial Statements**.

**Franchises and Other Rights**

Many of NMGC's transmission and distribution facilities are located on lands that require the grant of rights-of-way or franchises (collectively, ROW) from non-tribal governmental entities, Native American tribes and pueblos, or private landowners. In some cases, renewed ROWs must be submitted to the Federal Bureau of Indian Affairs (BIA) for approval. For the year ended Dec. 31, 2015, NMGC incurred expenditures for ROW renewals on Native American tribal and pueblo lands that amounted to $0.3 million.

In 2011, the New Mexico legislature passed legislation confirming the validity and enforceability of agreements with public utilities that provide access to public rights of way, including expired agreements that have continued to be honored by both the public utility and the local government according to their terms, regardless of the expiration date of the agreements. Accordingly, some of NMGC's expired ROWs remain in effect by statute, though NMGC expects to enter into negotiations to renew expired ROWs upon request. Based on current renewal experience with ROWs on Native American tribal and pueblo lands, NMGC believes that it is likely those ROWs will be renewed at prices that are significantly higher than historical levels. NMGC does not have condemnation rights on Native American tribal and pueblo lands, and, if it is unsuccessful in renewing some or all of these expiring or expired ROWs, it could be obligated to remove its facilities from, or abandon its facilities on, the property covered by the ROWs and seek alternative locations for its transmission or distribution facilities. With respect to land held by non-tribal governmental entities and privately-held land, however, NMGC may have condemnation rights and, thus, in the case where ROWs cannot be renewed by negotiation, NMGC would likely exercise such rights rather than remove or abandon facilities and find alternative locations for such facilities. Historically, ROW costs have been recovered in rates charged to customers, and NMGC will continue to seek to recover ROW costs in future rates charged to customers.

**Environmental Matters**

NMGC'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.

NMGC has no former MGP sites or material environmental liabilities. NMGC does not own any facilities or sites where investigation, material remediation, or monitoring of environmental conditions is ongoing or anticipated to be required. NMGC is unaware of any material soil or groundwater contamination for which it might be responsible under federal, state, or local laws or regulations. NMGC is a conditionally exempt small quantity generator with less than 100 kilograms of hazardous waste per month. Wastes are routinely characterized to determine whether or not they are subject to applicable hazardous waste regulations.

NMGC currently maintains two Title V (major source) air permits, for the Star Lake and Espejo Compressor Stations, and one minor source permit for the Cabezon Compressor Station. NMGC has submitted an application to the EPA for a synthetic minor source permit on Tribal lands for the Redonda Compressor Station. The remainder of its compressor stations are below the emission threshold for requiring a permit.

See **Environmental Compliance** section of the **MD&A** for additional information.

*Capital Expenditures*

During the year ended Dec. 31, 2015, NMGC did not incur any material capital expenditures to meet environmental requirements, nor are any anticipated for the 2016 through 2020 period.

**TECO COAL**

On Sept. 21, 2015, TECO Energy entered into an agreement and completed the sale of all of its ownership interest in TECO Coal to Cambrian. TECO Coal, formerly a wholly owned subsidiary of TECO Energy, had subsidiaries operating surface and underground mines as well as coal processing facilities in eastern Kentucky, Tennessee and southwestern Virginia.

TECO Coal owned no operating assets but held 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 owned, controlled and operated, by lease or mineral rights, surface and underground mines and coal processing and loading facilities. TECO Coal produced, processed and sold bituminous, predominately low sulfur coal of metallurgical, PCI, steam and industrial grades.

TECO Coal is accounted for in TECO Energy’s financial statements as an asset held for sale and discontinued operation through the date of sale. See **Note 19** to the **TECO Energy Consolidated Financial Statements** for more information.

**TECO GUATEMALA**

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

While TECO Energy and its subsidiaries no longer have assets or operations in Guatemala, TECO Guatemala Holdings, a wholly owned subsidiary of TECO Energy, has retained its rights under an arbitration claim against the Republic of Guatemala under the DR-CAFTA.

See **Notes 12** and **19** to the **TECO Energy Consolidated Financial Statements** for more information.

## 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 | 60 | President and Chief Executive Officer, TECO Energy, Inc., and Chief Executive Officer, Tampa Electric Company, August 2010 to date. |
| Charles A. Attal, III | 56 | Senior Vice President-General Counsel, Chief Legal Officer and Chief Ethics and Compliance Officer, TECO Energy, Inc. and General Counsel and Chief Ethics and Compliance Officer, Tampa Electric Company, June 2014 to date; and Senior Vice President-General Counsel and Chief Legal Officer, TECO Energy, Inc. and General Counsel of Tampa Electric Company, February 2009 to June 2014. |
| Phil L. Barringer | 62 | Senior Vice President of Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., Jan. 30, 2013 to date; Vice President of Corporate Services and Chief Human Resources Officer, TECO Energy, Inc., Jan. 1, 2013 to Jan. 30, 2013; Chief Human Resources Officer and Procurement Officer, Tampa Electric Company, January 2013 to date; Vice President-Human Resources of TECO Energy, Inc. and Tampa Electric Company, July 2009 to December 2012; and President, TECO Guatemala, July 2009 to date (operating companies sold December 2012). |
| Sandra W. Callahan | 63 | 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; and Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer), TECO Energy, Inc., October 2009 to February 2011. |
| Gordon L. Gillette | 56 | President, Tampa Electric Company, July 2009 to date. |
| Ryan A. Shell | 50 | President, New Mexico Gas Company, Inc., Dec. 31, 2014 to date; Vice President of Finance and Shared Services, New Mexico Gas Company, Inc., September 2014 to Dec. 31, 2014; Vice President of Finance and Treasurer, New Mexico Gas Company, Inc., February 2013 to September 2014; and Vice President, Controller and Treasurer, New Mexico Gas Company, Inc., January 2009 to February 2013. |

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 until such officer’s successor is elected and qualified.

## Item 1A. RISK FACTORS.

### Risks Associated with the Pending Acquisition by Emera

**TECO Energy and its subsidiaries are subject to business uncertainties and contractual restrictions while the Merger is pending that could adversely affect TECO Energy’s financial results.**

Uncertainty about the effect of the Merger on employees or vendors and others, including contractors, may have an adverse effect on TECO Energy. Although TECO Energy intends to take steps designed to reduce any adverse effects, these uncertainties may impair TECO Energy’s and its subsidiaries’ ability to attract, retain and motivate key personnel until the Merger is completed, and could cause vendors and others, including contractors, that deal with TECO Energy to seek to change existing business relationships. Employee retention and recruitment may be particularly challenging prior to the completion of the Merger, as current employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite TECO Energy’s retention and recruiting efforts, key employees depart or fail to accept employment with TECO Energy or its subsidiaries due to the uncertainty of employment and difficulty of integration or a desire not to remain with the combined company, following completion of the Merger. TECO Energy may incur significant costs in identifying, hiring, and retaining replacements for departing employees, which could have a material adverse effect on TECO Energy’s business operations and financial results.

TECO Energy expects that matters relating to the Merger and integration-related issues will place a significant burden on management, employees and internal resources, which could otherwise have been devoted to other business opportunities. The diversion of management time on Merger-related issues could affect TECO Energy’s financial results.

In addition, the Merger Agreement restricts TECO Energy and its subsidiaries, from taking specified actions until the Merger occurs or the Merger Agreement is terminated, without Emera's prior written consent, including, without limitation: (i) making certain material acquisitions and dispositions of assets or businesses; (ii) making any capital expenditures in excess of specified amounts; (iii) incurring indebtedness, subject to certain exceptions; (iv) issuing equity or equity equivalents; and (v) paying quarterly cash dividends in excess of levels agreed upon in the Merger Agreement. These restrictions may prevent TECO Energy from pursuing otherwise attractive business opportunities and making other changes to its business prior to consummation of the Merger or termination of the Merger Agreement.

**Failure to complete the Merger could negatively impact the market price of TECO Energy's common stock.**

There can be no assurance that the Merger will occur. Failure to complete the Merger may negatively impact the future trading price of TECO Energy's common stock. If the Merger is not completed, the market price of TECO Energy's common stock may decline to the extent that the current market price of TECO Energy's stock reflects a market assumption that there is a high probability that the Merger will be completed.

Additionally, whether or not the Merger is completed, TECO Energy will have incurred significant costs, as well as the diversion of the time and attention of management. A failure to complete the Merger may also result in negative publicity, litigation against TECO Energy or its directors and officers, and a negative impression of TECO Energy in the investment community. The occurrence of any of these events individually or in combination could have a material adverse effect on TECO Energy's financial condition, results of operations and its stock price.

**TECO Energy and Emera may be unable to obtain the required, governmental, regulatory, and other approvals required to complete the Merger.**

Consummation of the Merger is subject to the satisfaction or waiver of specified closing conditions, including (i) receipt of the remaining required regulatory approvals, including from the NMPRC, and the Committee on Foreign Investment in the United States; (iii) the absence of any law or judgement that prevents, makes illegal or prohibits the closing of the Merger; (iv) the absence of any material adverse effect with respect to TECO Energy; (v) subject to certain exceptions, the accuracy of the representations and warranties of, and compliance with covenants by, each of the parties to the Merger Agreement; and (vi) other customary closing conditions. The governmental, regulatory, and other approvals required to consummate the Merger may not be obtained at all, or may not be obtained on the proposed terms and schedules as contemplated by the parties. Satisfaction of the closing conditions may delay the consummation of the Merger, such delay may cause uncertainty or other negative consequences that may have an adverse effect on TECO Energy's business, financial condition and results of operations, cash flows and common stock price, and if certain closing conditions are not satisfied prior to the outside date specified in the Merger Agreement, Emera will not be obligated to consummate the Merger.

**In the event that the Merger Agreement is terminated prior to the completion of the Merger, TECO Energy could incur significant transaction costs that could materially impact its financial performance and results of operations.**

TECO Energy will incur significant transaction costs, including legal, accounting, financial advisory, filing, printing, and other costs relating to the Merger. The Merger Agreement provides that upon termination of the Merger Agreement under certain specified circumstances, TECO Energy will be required to pay Emera a termination fee of $212.5 million from cash on hand, short-term borrowings or a combination of those sources. Any fees due as a result of termination could have a material adverse effect on our results of operations, financial condition, and cash flows.

**We have been and may continue to be the target of securities class action suits and derivative suits which could result in substantial costs and divert management attention and resources**.

Securities class action suits and derivative suits are often brought against companies who have entered into mergers and acquisition transactions. Following the announcement of the execution of the Merger Agreement, 12 putative stockholder class actions were filed challenging the Merger. In November 2015, the defendants party to the litigation entered into a Memorandum of Understanding (the "MOU") with the various shareholder plaintiffs to settle, subject to court approval, all of the pending shareholder lawsuits challenging the proposed Merger. As a result of the MOU, TECO Energy made additional disclosures related to the proposed Merger in a proxy supplement filed on Nov. 18, 2015. The MOU provides for the parties to enter into a formal settlement agreement which will be submitted to the Hillsborough Circuit Court Judge for approval after completion of the Merger. Additionally the judge will consider the award of attorneys' fees to the plaintiffs' lawyers. See **Note 12** to the **TECO Energy Consolidated Financial Statements**. Defending against these claims, even if meritless, can result in substantial costs to us and could divert the attention of our management.

**General Risks**

**National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at TECO Energy and its subsidiaries.**

The business of TECO Energy is concentrated in Florida and New Mexico. While economic conditions in Florida and New Mexico have improved since the worst of the economic downturn in 2008, if they do not continue to improve or if they should worsen, retail customer growth rates may stagnate or decline, and customers' energy usage may further decline, adversely affecting TECO Energy's results of operations, net income and cash flows.

A factor in our customer growth in both Florida and New Mexico is net in migration of new residents, both domestic and non-U.S. A slowdown in the U. S. economy could reduce the number new residents and slow customer growth. In addition, New Mexico has significant oil and natural gas production from the San Juan and Permian production basins. The current low oil and natural gas-price environment has reduced drilling activity and oil and natural gas production in some producing regions, which has reduced employment in those industries and industries that serve them. A continuation of these conditions could slow growth in the New Mexico economy, which could reduce earnings and cash flow from NMGC.

**Developments in technology could reduce demand for electricity and gas.**

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, energy efficiency and more energy-efficient appliances and equipment. Advances in these or other technologies could reduce the cost of producing electricity or transporting gas, or otherwise make the existing generating facilities of Tampa Electric uneconomic. In addition, advances in such technologies could reduce demand for electricity or natural gas, which could negatively impact the results of operations, net income and cash flows of TECO Energy.

**TECO Energy's businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations.**

TECO Energy's utility businesses are affected by variations in general weather conditions and unusually severe weather. Energy sales by its electric and gas utilities 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 and NMGC, which typically have short but significant winter peak periods that are dependent on cold weather, are more weather-sensitive than Tampa Electric, which has both summer and winter peak periods. NMGC typically earns all of its net income in the first and fourth quarters, due to winter weather. Mild winter weather could negatively impact results at TECO Energy.

**TECO Energy's electric and gas utilities are highly regulated; changes in regulation or the regulatory environment could reduce revenues or increase costs or competition.**

TECO Energy's electric and gas utilities operate in highly regulated industries. Their retail operations, including the prices charged, are regulated by the FPSC in Florida and the NMPRC in New Mexico, 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 TECO Energy's utilities' 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, indicating an overearnings trend, those earnings could be subject to review by the FPSC. Ultimately, prolonged overearnings could result in credits or refunds to customers, which could reduce earnings and cash flow.

**Various factors relating to the integration of NMGC could adversely affect TECO Energy's business and operations.**

The anticipated accretion to earnings from NMGC during the original three-year integration period was based on estimates of synergies from the transaction and growth in the New Mexico economy, which are dependent on local and global economic conditions, normal weather and other factors, which may materially change, including:

- TECO Energy's estimate of NMGC's expected operating performance after the completion of the integration may vary significantly from actual results.
- Over time, TECO Energy will be making significant capital investments to convert several NMGC computer systems to the systems that TECO Energy uses in Florida. These conversions

may not be accomplished on time or on budget, which would increase costs for NMGC. In addition, the time required to convert these systems will cause NMGC to operate the existing systems past the end of their normal lives, which could reduce reliability.

- The potential loss of key employees of TECO Energy or NMGC who may be uncertain about their future roles in the TECO Energy/NMGC organization.

Negative impacts from these factors could have an adverse effect on TECO Energy's business, financial condition, and results of operations. Accordingly, the synergies expected from the acquisition of NMGC may not be achievable in the anticipated amount or timeframe, or at all.

**Changes in the environmental laws and regulations affecting its businesses could increase TECO Energy's costs or curtail its activities.**

TECO Energy's 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 TECO Energy, requiring cost-recovery proceedings and/or requiring it to curtail some of its businesses' activities.

**Regulations on the disposal and/or storage of CCRs could add to Tampa Electric's operating costs.**

The U.S. EPA published a new CCR rule in the U.S. Federal Register on April 17, 2015, setting federal standards for companies that dispose of CCRs in onsite landfills and impoundments. The rule went into effect on Oct. 19, 2015, and contains design and operating standards for CCR management units. Tampa Electric is currently evaluating various options for demonstrating compliance with the rule. The initial assessment is that activities in 2016 will consist primarily of monitoring and testing of the two existing CCR impoundments that are affected by this rule. Potential capital expenditures that may be required to comply with this rule are not expected to be significant. This rule is likely to face continued legal challenges by the utility industry and environmental groups, and legislation is required to fix certain portions of the rule. At this time, the ultimate outcome of any litigation or legislation is uncertain, so that it is not possible to predict the ultimate impact on Tampa Electric. While certain costs related to environmental compliance are currently recoverable from customers under Florida's ECRC, TECO Energy cannot be assured that any increased costs associated with the new regulations will be eligible for such treatment.

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

Among TECO Energy's companies, Tampa Electric has the most significant number of stationary sources with air emissions.

Current regulation in Florida allows utility companies to recover from customers prudently incurred costs for compliance with new state or federal 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 TECO Energy cannot be assured that the FPSC would grant such recovery. Under the Clean Power Plan, each state is responsible for implementing its own regulations to accord to the federal standards. Accordingly, a change in Florida's regulatory landscape could significantly increase Tampa Electric's costs. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on TECO Energy requiring FPSC cost recovery proceedings and/or requiring it to curtail some of its business activities.

The Clean Power Plan establishes state-specific emission rate and mass-based goals measured against a 2012 baseline. As Tampa Electric's investments in lower-GHG production largely occurred before 2012 and are factored into Florida's baseline generating capacity, Tampa Electric may encounter more difficulty than its competitors in achieving cost-effective GHG emission reductions. Because the ultimate form of Florida's state plan remains unknown, the increased compliance costs that Tampa Electric may face as a result of the Clean Power Plan are currently uncertain.

On Feb. 9, 2016, the U.S. Supreme Court issued a stay against enforcement of the Clean Power Plan for the electricity sector pending resolution of the legal challenges before the U.S. Court of Appeals for the District of Columbia Circuit. The timing of the resolution of the legal challenges and the removal of the stay by the U.S. Supreme Court is uncertain, but it is likely to delay further actions by the states until 2018.

**In 2015, there was a proposed constitutional ballot initiative for the 2016 election approved by the Florida Supreme Court to promote increased direct sale and use of solar energy to generate electricity which has now been delayed to the 2018 election. There is a corresponding legislative proposal for the current 2016 legislative session that could, if successful, promote increased direct sale and use of solar energy to generate electricity.**

The potential amendment to the Florida constitution in 2018 and potential corresponding 2016 legislation would encourage the installation of solar arrays to generate electricity by retail customers and third parties, and to allow sales of electricity by non-utility generators. Increased use of solar generation and sales by third parties would reduce energy sales and revenues at Tampa Electric. In addition, Tampa Electric could make investments in facilities to serve customers during periods that solar energy is not available that would not be profitable.

**NMGC operates high-pressure natural gas transmission pipelines, which involve risks that may result in accidents or otherwise affect its operations.**

There are a variety of hazards and operating risks inherent in operating high-pressure natural gas transmission pipelines, such as leaks, explosions, mechanical problems, activities of third parties and damage to pipelines, facilities and equipment caused by floods, fires and other natural disasters that may cause substantial financial losses. In addition, these risks could result in significant injury, loss of life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, known as High Consequence Areas, the level of damage resulting from these risks could be greater. NMGC does not maintain insurance coverage against all of these risks and losses, and any insurance coverage it might maintain may not fully cover damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on TECO Energy’s business, earnings, financial condition and cash flows.

**NMGC’s high-pressure transmission pipeline operations are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase TECO Energy’s cost of operations and affect or limit its business plans.**

TECO Energy’s pipeline operations are subject to pipeline safety regulation administered by the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) of the U.S. Department of Transportation. These laws and regulations require TECO Energy to comply with a significant set of requirements for the design, construction, maintenance and operation of its pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of its pipelines. The regulations determine the pressures at which its pipelines can operate.

PHMSA is designing an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand pipeline integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. Pipeline failures or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on TECO Energy’s pipelines. Should any of these risks materialize, it may have a material adverse effect on TECO Energy’s operations, earnings, financial condition and cash flows.

**Results at TECO Energy’s utilities may be affected by changes in customer energy-usage patterns.**

For the past several years, at Tampa Electric, and electric utilities across the United States, weather-normalized electricity consumption per residential customer has declined due to the combined effects of voluntary conservation efforts, economic conditions, and improvements in lighting and appliance efficiency.

Forecasts by TECO Energy’s utilities are based on normal weather patterns and historical trends in customer energy-usage patterns. The ability of TECO Energy’s utilities to increase energy sales and earnings could be negatively impacted if customers continue to use less energy in response to increased energy efficiency, economic conditions or other factors.

**TECO Energy’s computer systems and the infrastructure of its utility companies are 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, or otherwise adversely affect its business and financial results and condition.**

There have been an increasing number of cyberattacks 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, attachments to e-mails, through persons inside of the organization or through persons with access to systems inside of the organization.

TECO Energy has 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, TECO Energy cannot be assured that a cyberattack will not cause electric or gas system operational problems, disruptions of service to customers, compromise important data or systems, or subject it to additional regulation, litigation or damage to its reputation.

There have also been physical attacks on critical infrastructure at other utilities. While the transmission and distribution system infrastructure of TECO Energy's utility companies are designed and operated in a manner intended 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 TECO Energy's facilities or the industry in general, could also cause TECO Energy to incur additional security- and insurance-related costs, and could have adverse effects on its business and financial results and condition.

**Potential competitive changes may adversely affect TECO Energy's regulated electric and gas businesses.**

There is competition in wholesale power sales across the United States. 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 a number of years. Gas services provided by TECO Energy's gas utilities are unbundled for all non-residential customers. Because its gas utilities earn margins on distribution of gas but not on the commodity itself, unbundling has not negatively impacted TECO Energy's results. However, future structural changes could adversely affect PGS and NMGC.

**Increased customer use of distributed generation could adversely affect TECO Energy's regulated electric utility business.**

In many areas of the United States, 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. Additionally, the EPA's Clean Power Plan could have the effect of providing greater incentives for distributed generation in order to meet state-based emission reduction targets under the proposed rule.

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 that is not supported by increased energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

**The value of TECO Energy's 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 TECO Energy's existing deferred tax asset and could result in a charge to earnings from the write-down of that asset, and it would reduce future tax payments received by TECO Energy from its subsidiaries.

**TECO Energy relies on some natural gas transmission assets that it does not own or control to deliver natural gas. If transmission is disrupted, or if capacity is inadequate, TECO Energy's ability to sell and deliver natural gas and supply natural gas to its customers and its electric generating stations may be hindered.**

TECO Energy depends on transmission facilities owned and operated by other utilities and energy companies to deliver the natural gas it sells to the wholesale and retail markets, as well as the natural gas it purchases for use in its electric generation facilities. If transmission is disrupted, or if capacity is inadequate, its ability to sell and deliver products and satisfy its contractual and service obligations could be adversely affected.

**Disruption of fuel supply could have an adverse impact on the financial condition of TECO Energy.**

Tampa Electric, PGS and NMGC depend on third parties to supply fuel, including natural gas and coal. As a result, there are risks of supply interruptions and fuel-price volatility. Disruption of fuel supplies or transportation services for fuel, whether because of weather-related problems, strikes, lock-outs, break-downs of locks and dams, pipeline failures or other events, could impair the ability to deliver electricity or gas or generate electricity and could adversely affect operations. Further, the loss of coal suppliers or the inability to renew existing coal and natural gas contracts at favorable terms could significantly affect the ability to serve customers and have an adverse impact on the financial condition and results of operations of TECO Energy.

**Commodity price changes may affect the operating costs and competitive positions of TECO Energy's businesses.**

TECO Energy's businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes in the availability of these commodities could affect the prices charged by suppliers as well as suppliers' operating costs and the competitive positions 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 of, 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 and NMGC, 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 positions of PGS and NMGC as compared to electricity, other forms of energy and other gas suppliers.

**The facilities and operations of TECO Energy could be affected by natural disasters or other catastrophic events.**

TECO Energy's facilities and operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g. floods, high winds, fires and earthquakes), equipment failures, vandalism, potentially catastrophic events such as the occurrence of a major accident or incident at one of the sites, and other events beyond the control of TECO Energy. The operation of transmission and distribution systems involves certain risks, including gas leaks, fires, explosions, pipeline ruptures and other hazards and risks that may cause unforeseen interruptions, personal injury or property damage. Any such incident could have an adverse effect on TECO Energy and any costs relating to such events may not be recoverable through insurance or recovered in rates. In certain cases, there is potential that such an event may not excuse TECO Energy's utility companies from servicing customers as required by their respective tariffs.

**The franchise rights held by TECO Energy's utilities could be lost in the event of a breach by such TECO Energy utilities or could expire and not be renewed.**

TECO Energy's utilities hold franchise rights that are memorialized in agreements with selected counterparties throughout their service areas. In some cases these rights could be lost in the event of a breach of these agreements by the applicable TECO Energy utility. In addition, these agreements are for set periods and could expire and not be renewed upon expiration of the then-current terms. Some agreements also contain provisions allowing municipalities to purchase the portion of the applicable utility's system located within a given municipality's boundaries under certain conditions.

**Tampa Electric, PGS and NMGC may not be able to secure adequate rights of way to construct transmission lines, gas interconnection lines and distribution-related facilities and could be required to find alternate ways to provide adequate sources of energy and maintain reliable service for their customers.**

Tampa Electric, PGS and NMGC rely on federal, state and local governmental agencies and, in New Mexico, cooperation with local Native American tribes and councils, to secure rights of way and siting permits to construct transmission lines, gas interconnection lines and distribution-related facilities. If adequate rights of way and siting permits to build new transportation and transmission lines cannot be secured:

- Tampa Electric, PGS and NMGC may need to remove or abandon its facilities on the property covered by rights of way or franchises and seek alternative locations for its transmission or distribution facilities;
- Tampa Electric, PGS and NMGC may need to rely on more costly alternatives to provide energy to their customers;
- Tampa Electric, PGS and NMGC may not be able to maintain reliability in their service areas; and/or
- Tampa Electric's, PGS's and NMGC's ability to provide electric or gas service to new customers may be negatively impacted.

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

TECO Energy assesses 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, TECO Energy may be required to record non-cash impairment charges that could have a material adverse impact on TECO Energy's financial condition and results from operations. In connection with the NMGC acquisition, TECO Energy recorded additional goodwill and long-lived assets that could become impaired.

**TECO Energy has substantial indebtedness, which could adversely affect its financial condition and financial flexibility.**

TECO Energy has substantial indebtedness, which has resulted in fixed charges it is obligated to pay. The level of TECO Energy's indebtedness and restrictive covenants contained in its debt obligations could limit its ability to obtain additional financing (see **Management's Discussion & Analysis – Significant Financial Covenants** section).

TECO Energy, TECO Finance, TEC, NMGC and NMGI must meet certain financial covenants as defined in the applicable agreements to borrow under their respective credit facilities. Also, TECO Energy and its subsidiaries have certain restrictive covenants in specific agreements and debt instruments.

Although TECO Energy was in compliance with all required financial covenants as of Dec. 31, 2015, it cannot assure compliance with these financial covenants in the future. TECO Energy's failure to comply with any of these covenants or to meet its 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. TECO Energy may not have sufficient working capital or liquidity to satisfy its debt obligations in the event of an acceleration of all or a portion of its outstanding obligations. If TECO Energy's cash flows and capital resources are insufficient to fund its debt service obligations, it may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance its indebtedness. TECO Energy's ability to restructure or refinance its debt will depend on the condition of the capital markets and TECO Energy's financial condition at such time. Any refinancing of TECO Energy's debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments may restrict TECO Energy from adopting some of these alternatives.

TECO Energy also incurs obligations in connection with the operations of its subsidiaries and affiliates that do not appear on its balance sheet. Such obligations include guarantees, letters of credit and certain other types of contractual commitments.

**Financial market conditions could limit TECO Energy's access to capital and increase TECO Energy's costs of borrowing or refinancing, or have other adverse effects on its results.**

TECO Finance and TEC have debt maturing in 2016 and subsequent years, which may need to be refinanced. Future financial market conditions could limit TECO Energy's ability to raise the capital it needs and could increase its interest costs, which could reduce earnings. If TECO Energy is not able to issue new debt, or TECO Energy issues debt at interest rates higher than expected, its financial results or condition could be adversely affected.

**TECO Energy enters 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.**

TECO Energy enters into derivative transactions with counterparties, most of which are financial institutions, to hedge its exposure to commodity price and interest rate changes. Although TECO Energy believes it has 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 TECO Energy has an in-the-money position, TECO Energy could be unable to collect from such counterparty.

**Declines in the financial markets or in interest rates used to determine benefit obligations could increase TECO Energy's pension expense or the required cash contributions to maintain required levels of funding for its plan.**

Under calculation requirements of the Pension Protection Act, as of the Jan. 1, 2015, measurement date, TECO Energy's pension plan was essentially fully funded. Under MAP 21, TECO Energy is not required to make additional cash contributions over the next five years; however, TECO Energy may make additional cash contributions from time to time. Any future declines in the financial markets or further declines in interest rates could increase the amount of contributions required to fund its pension plan in the future, and could cause pension expense to increase.

**TECO Energy's financial condition and results could be adversely affected if its capital expenditures are greater than forecast.**

In 2016, TECO Energy is 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. TECO Energy is forecasting capital expenditures at PGS to support customer growth, system reliability, conversion of customers from other fuels to natural gas and to replace bare steel and cast iron pipe. Forecasted capital expenditures at NMGC are expected to support customer and system reliability and expansion.

If TECO Energy's capital expenditures exceed the forecasted levels, it may need to draw on credit facilities or access the capital markets on unfavorable terms. TECO Energy cannot be sure that it will be able to obtain additional financing, in which case its financial position could be adversely affected.

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

TECO Energy's senior unsecured debt is rated as investment grade by S&P at 'BBB', by Moody's at 'Baa1', and by 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-'. The senior unsecured debt of NMGC is rated by S&P at BBB+. 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 TECO Energy's ability to borrow, may change requirements for future collateral or margin postings, and may increase financing costs, which may decrease earnings. TECO Energy may also experience greater interest expense than it would have otherwise if, in future periods, it replaces maturing debt with new debt bearing higher interest rates due to any downgrades. In addition, downgrades could adversely affect TECO Energy's relationships with customers and counterparties.

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

**TECO Energy is a holding company with no business operations of its own and depends on cash flow from its subsidiaries to meet its obligations.**

TECO Energy is a holding company with no business operations of its own or material assets other than the stock of its subsidiaries. Accordingly, all of TECO Energy's operations are conducted by its subsidiaries. As a holding company, TECO Energy requires dividends and other payments from its subsidiaries to meet its cash requirements. If TECO Energy's subsidiaries are unable to pay it dividends or make other cash payments to it, TECO Energy may be unable to pay dividends or satisfy its obligations.

**In connection with the sale of TECO Coal to Cambrian, TECO Energy temporarily retained obligations under letters of indemnity that guarantee payments on bonds posted for the reclamation of mines prior to the completion of the transfer of all permits to the purchaser by the Commonwealths of Kentucky and Virginia.**

These letters of indemnity guarantee payments to certain surety companies that issued reclamation bonds to the Commonwealths of Kentucky and Virginia in connection with TECO Coal's mining operations. Payments by TECO Energy to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder or TECO Coal or one of the affiliates transferred to Cambrian as part of the sale did not pay the surety company. Pursuant to the SPA, Cambrian is obligated to file applications required in connection with the change of ownership and control of TECO Coal and its affiliates with the appropriate governmental entities with respect to the coal mining permits. Pursuant to the terms of the SPA, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond(s) secured by the TECO Energy indemnity for that permit. Until the bonds secured by TECO Energy's indemnity are released, TECO Energy's indemnity will remain effective. The company is working with Cambrian on the process of replacing the bonds and expects the process to be completed in 2016.

**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 2015 net winter generating capability of 4,730 MW. Tampa Electric assets include the Big Bend Power Station (1,632 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). See the **Tampa Electric – Polk Power Station Units 2-5 Combined Cycle Conversion** section of the **MD&A** for information regarding the Polk conversion project. In addition, Tampa Electric installed a 1.6 MW solar array at Tampa International Airport in December 2015.

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, and the four CTs began commercial operation from 2000 to 2007. Bayside Unit 1 was completed in April 2003, Unit 2 was completed in January 2004 and Units 3 through 6 were completed in 2009. Both the Phillips Power Station and the City of Tampa Partnership Station were retired in November 2015.

Tampa Electric owns 180 substations having an aggregate transformer capacity of 22,351 Mega Volts Amps. The transmission system consists of approximately 1,302 pole miles (including underground and double-circuit) of high voltage transmission lines, and the distribution system consists of 6,209 pole miles of overhead lines and 5,060 trench miles of underground lines. As of Dec. 31, 2015, there were 747,660 meters in service. All of this property is located in Florida.

All plants and important fixed assets are held in fee simple 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 ROW 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 19,000 miles of pipe, including approximately 12,100 miles of mains and 6,900 miles of service lines. Mains and service lines are maintained under ROW, 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.

**NEW MEXICO GAS COMPANY**

NMGC's distribution system extends throughout the areas it serves in New Mexico and consists of approximately 11,800 miles of pipe, including approximately 1,600 miles of transmission pipeline and 10,200 miles of distribution lines. Mains and service lines are maintained under ROW, franchises or permits.

NMGC's operations are located in six operating areas throughout New Mexico. While most of the operations and administrative facilities are owned, a small number are leased.

**Item 3. LEGAL PROCEEDINGS.**

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

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.**

During the time that it was a TECO Energy subsidiary, TECO Coal was 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 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 |
|---|---|---|---|---|
| *2015* | | | | |
| High | $ 22.02 | $ 19.94 | $ 26.87 | $ 27.23 |
| Low | 18.55 | 17.60 | 17.61 | 26.08 |
| Close | 19.40 | 17.66 | 26.26 | 26.65 |
| Dividend | $ 0.225 | $ 0.225 | $ 0.225 | $ 0.225 |
| | | | | |
| *2014* | | | | |
| High | $ 17.31 | $ 18.53 | $ 18.48 | $ 21.29 |
| Low | 16.12 | 16.90 | 16.91 | 17.35 |
| Close | 17.15 | 18.48 | 17.38 | 20.49 |
| 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. 12, 2016 was 10,164.

The primary sources of funds to pay dividends to TECO Energy's common shareholders are dividends and other distributions from its operating companies. Dividends on TECO Energy's common stock are declared and paid at the discretion of its Board of Directors. The Merger Agreement with Emera restricts TECO Energy and its subsidiaries, without Emera's prior written consent, from issuing equity or equity equivalents and from paying quarterly cash dividends in excess of levels agreed upon in the Merger Agreement until the Merger occurs or the Merger Agreement is terminated.

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. See **Note 21** to the **TECO Energy Consolidated Financial Statements** for additional information regarding the pending Merger**.**

All of TEC's common stock is owned by TECO Energy and, therefore, there is no market for such stock. TEC pays dividends on its common stock substantially equal to its net income. Such dividends totaled $268.4 million in 2015, $262.6 million in 2014 and $222.1 million in 2013.

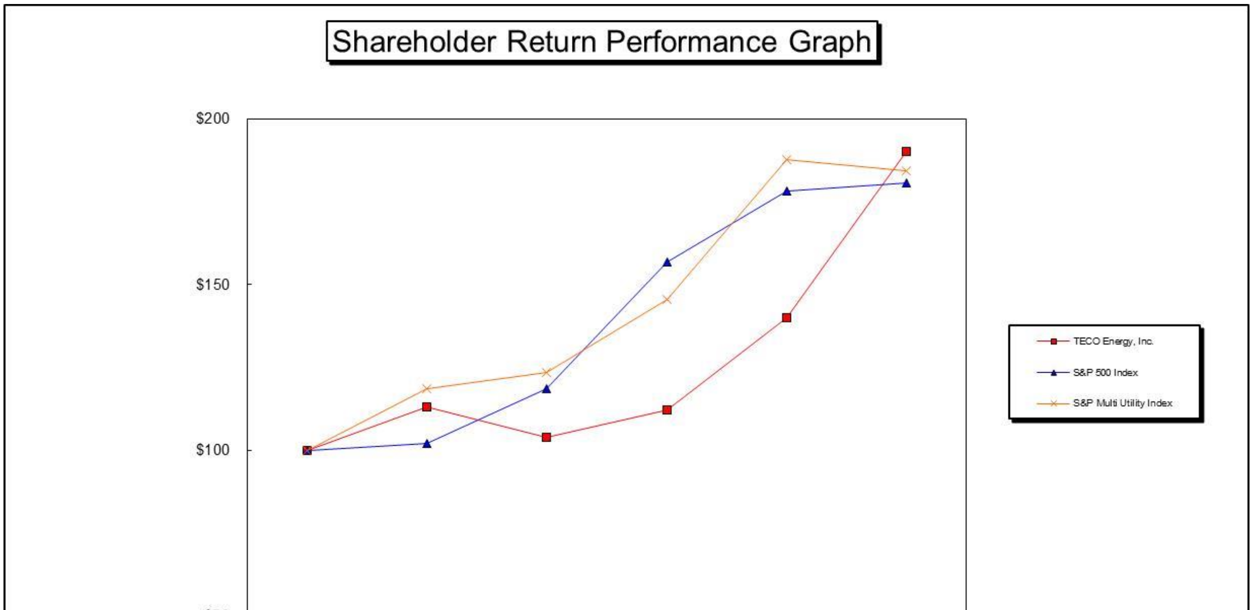
Set forth below is a table showing shares of TECO Energy common stock deemed repurchased by the issuer.

| | 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, 2015 – Oct. 31, 2015 | 32,763 | $ 26.27 | 0.0 | 0.0 |
| Nov. 1, 2015 – Nov. 30, 2015 | 8,272 | $ 26.59 | 0.0 | 0.0 |
| Dec. 1, 2015 – Dec. 31, 2015 | 636 | $ 26.60 | 0.0 | 0.0 |
| Total 4th Quarter 2015 | 41,671 | $ 26.34 | 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, 2015, and compares this return with that of the S&P 500 Index and the S&P Multi Utility Index. The graph assumes that the value of the investment in TECO Energy's common stock and each index was $100 on Dec. 31, 2010 and that all dividends were reinvested.




| | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 |
|---|---|---|---|---|---|---|
| TECO Energy, Inc. | $100 | $113 | $104 | $112 | $140 | $190 |
| S&P 500 Index | $100 | $102 | $118 | $157 | $178 | $181 |
| S&P Multi Utility Index | $100 | $118 | $123 | $145 | $188 | $184 |

**Item 6. SELECTED FINANCIAL DATA OF TECO ENERGY**

| *(millions, except per share amounts)* *Years ended Dec. 31,* | *2015* | *2014* | *2013* | *2012* | *2011* |
|---|---|---|---|---|---|
| Revenues [1] | $ 2,743.5 | $ 2,566.4 | $ 2,355.1 | $ 2,387.7 | $ 2,476.9 |
| Net income from continuing operations [1] | 241.2 | 206.4 | 188.7 | 197.0 | 200.6 |
| Net income from discontinued operations [1] | (67.7) | (76.0) | 9.0 | 15.7 | 72.0 |
| Net income | 173.5 | 130.4 | 197.7 | 212.7 | 272.6 |
| Total assets | 8,961.1 | 8,726.2 | 7,448.0 | 7,334.9 | 7,307.2 |
| Long-term debt, including current portion | 3,850.2 | 3,628.5 | 2,921.1 | 2,972.7 | 3,073.4 |
| EPS - Basic | | | | | |
| From continuing operations [1] | $ 1.03 | $ 0.92 | $ 0.88 | $ 0.92 | $ 0.93 |
| From discontinued operations [1] | (0.29) | (0.34) | 0.04 | 0.07 | 0.34 |
| | $ 0.74 | $ 0.58 | $ 0.92 | $ 0.99 | $ 1.27 |
| EPS - Diluted | | | | | |
| From continuing operations [1] | $ 1.03 | $ 0.92 | $ 0.88 | $ 0.92 | $ 0.93 |
| From discontinued operations [1] | (0.29) | (0.34) | 0.04 | 0.07 | 0.34 |
| | $ 0.74 | $ 0.58 | $ 0.92 | $ 0.99 | $ 1.27 |
| Dividends paid per common share outstanding | $ 0.900 | $ 0.880 | $ 0.880 | $ 0.880 | $ 0.850 |

(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 pending acquisition by Emera, Inc., 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, and elsewhere in this MD&A."*

*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 a utility holding company with regulated electric and gas utility operations in Florida and New Mexico.

Our largest subsidiary, Tampa Electric Company, includes regulated electric and gas utility operations in Florida. Tampa Electric serves almost 720,000 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 4,730 MW. PGS, Florida's largest gas distribution utility, serves more than 360,000 residential, commercial, industrial and electric power generating customers in all major metropolitan areas of the state, with a total natural gas throughput of almost 1.8 billion therms in 2015.

Our NMGC utility subsidiary is New Mexico's largest regulated natural gas distribution utility and serves more than 516,000, primarily residential customers in 23 of New Mexico's 33 counties, with total natural gas throughput of 775 million therms in 2015.

### PENDING ACQUISITION BY EMERA

As previously announced, on Sept. 4, 2015, we entered into an Agreement and Plan of Merger with Emera and Emera US Inc., a Florida corporation ("Merger Sub").

Upon the terms and subject to the conditions set forth in the Merger Agreement, which was unanimously approved and adopted by the board of directors of TECO Energy, at the effective time, Merger Sub will merge with and into TECO Energy (the "Merger") with TECO Energy continuing as the surviving corporation.

Pursuant to the Merger Agreement, upon the closing of the Merger, each issued and outstanding share of TECO Energy common stock will be cancelled and converted automatically into the right to receive $27.55 in cash, without interest.

On Dec. 3, 2015, our shareholders representing a majority of the outstanding shares of TECO Energy common stock approved the Merger. On Jan. 20, 2016, the FERC approved the acquisition, finding the transaction is consistent with the public interest, and on Feb. 5, 2016, the applicable Hart-Scott-Rodino Act waiting period expired. On Jan. 6, 2016, TECO Energy and Emera made the initial filings required to obtain approval of the Merger with CFIUS. The closing of the Merger remains subject to, (i) receipt of remaining regulatory approvals, including the approval of the NMPRC, (ii) the absence of any law or judgment that prevents, makes illegal or prohibits the closing of the Merger, (iii) the absence of any material adverse effect with respect to TECO Energy and (iv) subject to certain exceptions, the accuracy of the representations and warranties of, and compliance with covenants by, each of the parties to the Merger Agreement.

The Merger Agreement contains customary representations, warranties and covenants of TECO Energy, Emera and Merger Sub. The Merger Agreement contains covenants by TECO Energy, among others, that (i) TECO Energy will conduct its business in the ordinary course during the interim period between the execution of the Merger Agreement and the closing of the Merger and (ii) TECO Energy will not engage in certain transactions during such interim period. The Merger Agreement contains covenants by Emera, including that Emera will use its reasonable best efforts to take all actions necessary to obtain all governmental and regulatory approvals.

In addition, the Merger Agreement requires Emera (i) to maintain TECO Energy's historic levels of community involvement and charitable contributions and support in TECO Energy's existing service territories, (ii) to maintain TECO Energy's headquarters in Tampa, FL, (iii) to honor current union contracts in accordance with their terms and (iv) to provide each continuing non-union employee, for a period of two years following the closing of the Merger, with a base salary or wage rate no less favorable than, and incentive compensation and employee benefits, respectively, substantially comparable in the aggregate to those that they received as of the time immediately prior to the closing.

TECO Energy is also subject to a "no-shop" restriction that limits its ability to solicit alternative acquisition proposals or provide nonpublic information to, and engage in discussion with, third parties.

The Merger Agreement contains certain termination rights for both TECO Energy and Emera. Either party may terminate the Merger Agreement if (i) the closing of the Merger has not occurred by Sept. 30, 2016, (subject to a 6-month extension if required to obtain necessary regulatory approvals), (ii) a law or judgment preventing or prohibiting the closing of the Merger has become final, (iii) TECO Energy's shareholders do not approve the Merger (which approval was received on Dec. 3, 2015) or (iv) TECO Energy's board of directors changes its recommendation so that it is no longer in favor of the Merger. If either party terminates the Merger Agreement because TECO Energy's board of directors changes its recommendation, TECO Energy must pay Emera a termination fee of $212.5 million. If the Merger Agreement is terminated under certain other circumstances, including the failure to obtain required regulatory approvals, Emera must pay TECO Energy a termination fee of $326.9 million.

The Merger Agreement contains representations and warranties by each of the parties to the Merger Agreement, which are made solely for the benefit of the other parties to the Merger Agreement. The representations and warranties in the Merger Agreement (i) are not intended to be treated as categorical statements of fact but rather as a way of allocating risk to one of the parties if any such representation or warranty proves to be inaccurate, (ii) may have been qualified in the Merger Agreement by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, (iii) may be subject to standards of materiality applicable to the parties to the Merger Agreement that differ from what might be viewed as material to shareholders of such party and (iv) were made only as of the date of the Merger Agreement or such other date or dates as may be specified in the Merger Agreement. TECO Energy's shareholders should not rely on the representations, warranties and covenants, or any descriptions thereof, as characterizations of the actual state of facts or condition of TECO Energy, Emera or Merger Sub.

Following the announcement of the Emera transaction, there were 12 securities class-action lawsuits filed against us and our directors, alleging that the members of the board breached their fiduciary duties in agreeing to the Merger agreement. In November 2015, the parties to the lawsuits entered into a Memorandum of Understanding (MOU) with the various shareholder plaintiffs to settle, subject to court approval, all of the pending shareholder lawsuits challenging the proposed Merger. As a result of the MOU, we made additional disclosures related to the proposed Merger in a proxy supplement. The MOU provides for the parties to enter into a formal settlement agreement which will be submitted to the Hillsborough Circuit Court Judge for approval after completion of the Merger. Additionally, the judge will consider the award of attorneys' fees to the plaintiffs' lawyers (see **Note 12** to the **TECO Energy Consolidated Financial Statements)**.

## ACQUISITION OF NEW MEXICO GAS CO.

We acquired NMGC in September 2014. With the addition of NMGC's more than 516,000 gas customers, TECO Energy utility subsidiaries now serve almost 890,000 gas distribution customers in two states, and almost 1.6 million regulated electric and gas customers in Florida and New Mexico.

The aggregate purchase price for the acquisition was $950 million, which included the assumption of $200 million of existing debt. The transaction was financed through cash on hand at TECO Energy parent, proceeds from the issuance of $292 million of TECO Energy common stock, the issuance of $270 million of private placement debt at NMGI and NMGC, which was used to retire $219 million of existing NMGC and NMGI debt, and short-term borrowings at TECO Finance.

Strategic benefits of the acquisition include:

- A transformative transaction that immediately added almost 513,000 customers in a single state.
- Provides an opportunity for TECO Energy's experienced management team to share marketing expertise in a growing service territory, and for both companies to share best practices to support growth.
- Diversifies TECO Energy's operating footprint.
- Provides immediate to near-term shareholder and customer benefits through organic growth opportunities.
- Accretive to full-year earnings in 2015.

## SALE OF TECO COAL

On Sept. 21, 2015, TECO Diversified, a wholly-owned subsidiary of TECO Energy, entered into a Securities Purchase Agreement (the "SPA") for the sale of TECO Coal LLC to Cambrian Coal Corp. The SPA did not provide for an up-front purchase payment, but provides for contingent payments of up to $60 million that may be paid in the years up to 2019 depending on specified coal benchmark prices. TECO Energy retains certain personnel related liabilities, but all other TECO Coal liabilities were transferred in the transaction. The retained liabilities included pension liability, which was fully funded at June 30, 2015, and severance agreements, which were paid in 2015. In addition, we retained obligations under letters of indemnity that guarantee payments on bonds posted for the reclamation of mines prior to the transfer of all permits to the purchaser by the Commonwealths of Kentucky and Virginia. We are working with the purchaser and the respective permitting agencies to have all permits transferred to the purchaser by the end of 2016 (see the **Risk Factors** section).

The SPA called for a simultaneous signing and closing, which occurred on Sept. 21, 2015. The closing of this sale completed the process of exiting unregulated operations to focus on regulated utility businesses.

As a result of our Board of Directors authorizing us to enter into negotiations for the sale of TECO Coal, effective in the third quarter of 2014 it was classified as asset held for sale and its results for all periods presented are classified as discontinued operations. TECO Energy recorded a non-cash valuation adjustment of approximately $76 million, after tax, to the carrying value of TECO Coal to reflect the sales price specified under a sales agreement entered into in October 2014, and an additional $51 million impairment charge, including a $7.7 million charge related to black lung liabilities was recorded in 2015. (See the **Discontinued Operations** section later in this MD&A.)

## 2015 PERFORMANCE

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

In 2015, our net income was $173.5 million, or $0.74 per share, compared with $130.4 million, or $0.58 per share, in 2014. In 2015, net income from continuing operations was $241.2 million, or $1.03 per share, compared with $206.4 million, or $0.92 per share, in 2014. The $67.7 million loss from discontinued operations in 2015 includes the operating results from TECO Coal, impairment charges totaling $50.8 million, and the $7.7 million charge related to black lung liabilities. The $76.0 million loss from discontinued operations in 2014 included the operating results from TECO Coal, impairment charges of $76.4 million and items related to the 2012 sale of TECO Guatemala.

In 2015 and 2014, non-GAAP results from continuing operations, which exclude $15.0 million and $23.3 million of acquisition-related charges, respectively, were $256.2 million, or $1.10 on a per-share basis, compared with $229.7 million, or $1.03 on a per-share basis. See the **2015 and 2014 GAAP – Non-GAAP Reconciliation Table** below.

The most significant factors impacting the year-over-year-comparison of net income and non-GAAP results were the $37 million of higher pretax base revenue at Tampa Electric as a result of its 2013 rate case settlement and higher energy sales due to more favorable weather in 2015 than in 2014, and the addition of NMGC for the full year. Tampa Electric and PGS benefited from customer growth of 1.8% and 2.1%, respectively.

## OUTLOOK

Our outlook for 2016 reflects our expectation that our Florida utilities will deliver strong earnings growth, earning returns above the mid-point of their allowed ROE ranges, and that all of the utilities will continue to experience customer growth at levels similar to or better than 2015 levels and will continue to focus on cost control. The drivers impacting 2016 are summarized below and discussed in further detail in the individual operating company sections.

Tampa Electric expects to earn in the upper half of its allowed ROE range of 9.25% to 11.25%, driven by $5.0 million of higher base revenues that were effective Nov. 1, 2015 as a result of its September 2013 rate case settlement agreement, average customer growth trends similar to or slightly better than those experienced in 2015 and higher AFUDC primarily related to the Polk Power Station conversion project. Weather-normalized retail energy sales are expected to increase at a rate about 0.3% to 0.5% below the rate of customer growth. These sales forecasts reflect the impact of improved lighting and appliance efficiency and customer energy conservation. Full-year O&M expense is expected to be lower than 2015 due to lower employee-related costs, a focus on cost control and the impact of synergies in Florida due to the NMGC integration. Depreciation expense is expected to be higher due to normal additions to facilities to serve customers.

PGS expects to continue to earn in the upper half of its allowed ROE range of 9.75% to 11.75% from average customer growth trends similar to or slightly better than those experienced in 2015 and continued interest from customers utilizing petroleum and other fuel sources to convert to natural gas. O&M expense and depreciation trends are expected to be similar to Tampa Electric.

NMGC expects 2016 average customer growth of more than 0.7% and volume growth at about the same level as experienced in 2015. Consistent with the terms of the NMPRC approval of the acquisition, NMGC will continue to credit $4.0 million to customer bills in each 12-month period until new base rates are established.

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 utilities to support their capital spending programs while maintaining their capital structures and financial integrity, and reduction of parent debt over time. In 2016, we expect to make additional equity contributions to Tampa Electric of approximately $150 million. We anticipate capital spending at the Florida utilities in 2016 to be at comparable levels to 2015 at approximately $685 million, including the investments in generating capacity additions at Tampa Electric and opportunities to grow the PGS system described below. We expect NMGC capital expenditures of approximately $80 million to support modest customer growth and system reliability (see the **Liquidity, Capital Resources** section).

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 42 CNG filling stations with completed conversions of more than 1,400 vehicles of various sizes to CNG. In 2016, the number of vehicles already converted or committed to conversion will consume almost 22 million therms annually, the equivalent consumption of more than 94,000 typical Florida residential customers. Such conversions offer compelling economics to customers, and expand PGS therm sales without significant capital investment by PGS. The interest in converting vehicle fleets to natural gas remains strong even in the low oil-price environment, due to the lower emissions profile of CNG fueled vehicles and the outlook for continued low natural gas prices. In January 2016, we placed the first CNG filling station owned by PGS in service. The cost of this station will be recovered over time through a special rate approved by the FPSC. We expect to open other stations owned by PGS in the future.
- There are opportunities to expand the use of CNG for vehicle fleets in New Mexico over the longer-term. Current rates to provide CNG service in New Mexico were established many years ago as an experiment to encourage the growth in CNG vehicles. It is currently not profitable to provide CNG service at the existing rates, which cannot be adjusted until new rates are established after the end of 2017 (see the **Regulation Section – NMGC Base Rates**). When new rates are established, NMGC expects to promote the conversion of vehicle fleets to CNG as PGS has done in Florida.
- We are taking the first steps necessary, through our Customer Relationship Management software project, to implement Smart Grid applications that use proven technology and offer operating and financial benefits to our customers and 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 result in O&M savings.
- We recognize that there is a growing demand for natural-gas-fired power generation in Florida over the next decade. We project that Florida may need between 0.8 billion and 1.25 billion cubic feet per day (Bcf/day). Given PGS' expertise in this area, we continue to evaluate opportunities to partner with transmission and end-use natural gas customers for the construction of laterals to connect the transmission provider to the end users.
- In 2015, we announced plans for a 23 MW utility-scale solar photo-voltaic project to be installed and completed in 2016 at Tampa Electric's Big Bend Station. In 2015, we completed the construction of a 2 MW solar photo voltaic energy installation at Tampa International Airport, which we own and operate. We anticipate developing additional solar photo voltaic installations in the future.

In addition, 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. During the financial crisis, there were few large active residential projects, which caused PGS to focus on converting the larger commercial and industrial customers to natural gas. Commercial and industrial-led expansion during the economic downturn allowed PGS to continue to provide clean and economical natural gas to areas of the state previously unserved and to be positioned to serve future growth. With 1,000 new residents currently moving to Florida daily, residential construction in Florida has rebounded in a number of key markets across the state, which has resulted in higher demand for natural gas use by residential customers. The combination of renewed residential construction, continued interest by commercial and industrial customers in converting to natural gas, and the growing interest in the conversion of vehicle fleets to CNG is contributing to strong growth at PGS.

We are expanding marketing activities at NMGC by deploying the marketing skills developed by PGS in Florida to New Mexico to grow that business. Areas of focus include conversion of large commercial or industrial customers using petroleum-based fuels to natural gas, developing the CNG market for vehicle fleets in New Mexico, as PGS has successfully done in Florida, and support of economic development in New Mexico.

## 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 2015, 2014 and 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)* | ***2015*** | *2014* | *2013* |
|---|---|---|---|
| Net income | **$ 173.5** | $ 130.4 | $ 197.7 |
| Net income from continuing operations | **$ 241.2** | $ 206.4 | $ 188.7 |
| Non-GAAP results from continuing operations | **$ 256.2** | $ 229.7 | $ 194.9 |

The table below provides a summary of revenues, earnings per share, net income and shares outstanding for the 2015-2013 period.

### Earnings Summary

| *(millions) Except per-share amounts* | ***2015*** | *2014* | *2013* |
|---|---|---|---|
| **Consolidated revenues** | **$ 2,743.5** | $ 2,566.4 | $ 2,355.1 |
| **Earnings per share – basic** | | | |
| Earnings per share | **$ 0.74** | $ 0.58 | $ 0.92 |
| Earnings (loss) per share from discontinued operations | **(0.29)** | (0.34) | 0.04 |
| Earnings per share before discontinued operations | **$ 1.03** | $ 0.92 | $ 0.88 |
| **Earnings per share – diluted** | | | |
| Earnings per share | **$ 0.74** | $ 0.58 | $ 0.92 |
| Earnings (loss) per share from discontinued operations | **(0.29)** | (0.34) | 0.04 |
| Earnings per share before discontinued operations | **$ 1.03** | $ 0.92 | $ 0.88 |
| Net income | **$ 173.5** | $ 130.4 | $ 197.7 |
| Net income (loss) from discontinued operations | **(67.7)** | (76.0) | 9.0 |
| Charges and (gains)[1] | **15.0** | 23.3 | 6.2 |
| Non-GAAP results | **$ 256.2** | **$ 229.7** | **$ 194.9** |
| | | | |
| **Average common shares outstanding (millions)** | | | |
| Basic | **233.1** | 223.1 | 215.0 |
| Diluted | **234.5** | 223.7 | 215.5 |

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

The following tables show the specific adjustments made to GAAP net income for each segment to develop our 2015, 2014 and 2013 non-GAAP results.

**2015 Reconciliation of GAAP Net Income to Non-GAAP Results**

| Net income impact (millions) | Tampa Electric | PGS | NMGC | TECO Coal [1] | Other (net) [1] | Total |
|---|---|---|---|---|---|---|
| GAAP net income | $ 241.0 | $ 35.3 | $ 24.1 | $ (69.6) | $ (57.3) | $ 173.5 |
| Net income (loss) from discontinued operations | 0.0 | 0.0 | 0.0 | (69.6) | 1.9 | (67.7) |
| Net income (loss) from continued operations | 241.0 | 35.3 | 24.1 | 0.0 | (59.2) | 241.2 |
| Costs associated with the integration of NMGC | 0.0 | 0.0 | 0.0 | 0.0 | 1.9 | 1.9 |
| Costs associated with the pending acquisition by Emera | 0.0 | 0.0 | 0.0 | 0.0 | 13.1 | 13.1 |
| Total charges | 0.0 | 0.0 | 0.0 | 0.0 | 15.0 | 15.0 |
| Non-GAAP results | $ 241.0 | $ 35.3 | $ 24.1 | $ 0.0 | $ (44.2) | $ 256.2 |

**2014 Reconciliation of GAAP Net Income to Non-GAAP Results**

| Net income impact (millions) | Tampa Electric | PGS | NMGC | TECO Coal [1] | Other (net) [1] | Total |
|---|---|---|---|---|---|---|
| GAAP net income | $ 224.5 | $ 35.8 | $ 10.5 | $ (82.0) | $ (58.4) | $ 130.4 |
| Net income (loss) from discontinued operations | 0.0 | 0.0 | 0.0 | (82.0) | 6.0 | (76.0) |
| Net income (loss) from continued operations | 224.5 | 35.8 | 10.5 | 0.0 | (64.4) | 206.4 |
| Costs associated with the acquisition of NMGC | 0.0 | 0.0 | 0.0 | 0.0 | 16.6 | 16.6 |
| Consolidated deferred tax balance adjustment | 0.0 | 0.0 | 0.0 | 0.0 | 6.7 | 6.7 |
| Total charges and (gains) | 0.0 | 0.0 | 0.0 | 0.0 | 23.3 | 23.3 |
| Non-GAAP results | $ 224.5 | $ 35.8 | $ 10.5 | $ 0.0 | $ (41.1) | $ 229.7 |

**2013 Reconciliation of GAAP Net Income to Non-GAAP Results**

| Net income impact (millions) | Tampa Electric | PGS | NMGC | TECO Coal [1] | Other (net) [1] | Total |
|---|---|---|---|---|---|---|
| GAAP net income | $ 190.9 | $ 34.7 | $ 0.0 | $ 9.0 | $ (36.9) | $ 197.7 |
| Net income (loss) from discontinued operations | 0.0 | 0.0 | 0.0 | 9.0 | 0.0 | 9.0 |
| Net income (loss) from continued operations | 190.9 | 34.7 | 0.0 | 0.0 | (36.9) | 188.7 |
| Costs associated with the acquisition of NMGC | 0.0 | 0.0 | 0.0 | 0.0 | 6.2 | 6.2 |
| Total charges | 0.0 | 0.0 | 0.0 | 0.0 | 6.2 | 6.2 |
| Non-GAAP results | $ 190.9 | $ 34.7 | $ 0.0 | $ 0.0 | $ (30.7) | $ 194.9 |

(1) TECO Coal results and certain other costs previously included in Other (net) 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. We 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 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* | | ***2015*** | *2014* | *2013* |
|---|---|---|---|---|
| **Segment revenues** (1) | | | | |
| | Tampa Electric | **$ 2,018.3** | $ 2,021.0 | $ 1,950.5 |
| | PGS | **407.5** | 399.6 | 393.5 |
| | NMGC | **316.5** | 137.5 | 0.0 |
| Total utility companies | | **$ 2,742.3** | $ 2,558.1 | $ 2,344.0 |
| **Net income** (2) | | | | |
| | Tampa Electric | **$ 241.0** | $ 224.5 | $ 190.9 |
| | PGS | **35.3** | 35.8 | 34.7 |
| | NMGC | **24.1** | 10.5 | 0.0 |
| Total utility companies | | **300.4** | 270.8 | 225.6 |
| | Other (net) (4) | **(59.2)** | (64.4) | (36.9) |
| Net income from continuing operations (4) | | **241.2** | 206.4 | 188.7 |
| Net income (loss) from discontinued operations (2) | | **(67.7)** | (76.0) | 9.0 |
| Net income attributable to TECO Energy | | **$ 173.5** | $ 130.4 | $ 197.7 |
| **Earnings per share - basic** (3) | | | | |
| | Tampa Electric | **$ 1.03** | $ 1.00 | $ 0.89 |
| | PGS | **0.15** | 0.16 | 0.16 |
| | NMGC | **0.10** | 0.05 | 0.0 |
| Total utility companies | | **1.28** | 1.21 | 1.05 |
| | Other (net) (4) | **(0.25)** | (0.29) | (0.17) |
| Earnings per share from continuing operations | | **1.03** | 0.92 | 0.88 |
| Earnings (loss) per share from discontinued operations (2) | | **(0.29)** | (0.34) | 0.04 |
| Earnings per share attributable to TECO Energy | | **$ 0.74** | $ 0.58 | $ 0.92 |
| Average shares outstanding – basic | | **233.1** | 223.1 | 215.0 |

(1) Segment revenues include intercompany transactions that are eliminated in the preparation of TECO Energy's consolidated financial statements.
(2) Prior to its classification as Asset Held for Sale, the TECO Coal segment net income and earnings per share included in discontinued operations were reported on a basis that includes internally allocated pretax interest costs of $3.0 million through June 2014 and $6.4 million in 2013. Internally allocated interest costs were at a pretax interest rate of 6.00% for 2014 and 2013.
(3) The number of shares used in the earnings-per-share calculations is basic shares.
(4) Net income from continuing operations including charges of $15.0 million in 2015, $23.3 million in 2014 and $6.2 million in 2013.

## TAMPA ELECTRIC

### Electric Operations Results

Net income in 2015 was $241.0 million, compared with $224.5 million in 2014, driven by 1.8% higher average number of customers and higher energy sales resulting from customer growth, warmer than normal spring and early winter weather and a stronger economy. Higher operations and maintenance, depreciation and interest expenses partially offset the higher revenues. Full-year net income in 2015 included $17.2 million of AFUDC equity, compared with $10.5 million in 2014.

In 2015, total degree days in Tampa Electric's service area were 12% above normal and 17% above 2014 levels. Pretax base revenue was more than $37 million higher than in 2014, including approximately $8 million of higher pretax base revenue as a result of the base rate increases effective Nov. 1, 2014 and 2015. In 2015, total net energy for load, which is a calendar measurement of retail energy sales rather than a billing cycle measurement, was 4.1% higher than in 2014. Higher energy sales were driven by more favorable weather throughout the year in 2015 than in 2014.

O&M expenses, excluding all FPSC-approved cost-recovery clauses, increased $5.4 million in 2015, reflecting higher costs to safely and reliably serve customers that were partially offset by lower employee-related expenses. Compared to 2014, depreciation and amortization expense increased $5.0 million, reflecting additions to facilities to serve customers. Interest expense increased $1.4 million due to higher long-term debt balances. Results also include a $1.9 million loss on the disposition of small generating units no longer in service.

Net income in 2014 was $224.5 million, compared with $190.9 million in 2013, driven primarily by the benefits from the 2013 rate case settlement, higher energy sales from strong average customer growth, a stronger economy, and lower O&M. Net income in 2014 included $10.5 million of AFUDC equity, which represents allowed equity cost capitalized to construction costs, compared with $6.3 million in 2013. These items were partially offset by higher depreciation expense, and $2.9 million lower earnings on assets recovered through the ECRC.

In 2014, total degree days in Tampa Electric's service area were 4% below normal, and 3% below 2013 levels, driven by milder fourth quarter weather. Pretax base revenue included almost $50 million of higher revenue as a result of the 2013 rate case settlement. In 2014, total net energy for load was 0.7% higher than in 2013, driven by customer growth. Sales to lower-margin, industrial-phosphate customers were lower as self-generation by these customers increased.

O&M expense, excluding all FPSC-approved cost-recovery clauses, decreased $1.0 million in 2014, reflecting lower employee-related costs, including pension expense, and the elimination of the storm damage reserve accrual, partially offset by higher costs to operate and maintain the system. Compared to 2013, depreciation and amortization expense increased $6.0 million, reflecting additions to facilities to serve customers.

**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 an extensive process by Tampa Electric, 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)* | ***2015*** | *% Change* | *2014* | *% Change* | *2013* |
|---|---|---|---|---|---|
| Revenues | **$ 2,018.3** | (0.1) | $ 2,021.0 | 3.6 | $ 1,950.5 |
| O&M expense | **420.6** | 0.5 | 418.4 | (2.0) | 427.0 |
| Depreciation and amortization | **256.7** | 3.3 | 248.6 | 4.1 | 238.8 |
| Taxes, other than income | **156.4** | 1.1 | 154.7 | 3.3 | 149.7 |
| Non-fuel operating expenses | **833.7** | 1.4 | 821.7 | 0.8 | 815.5 |
| Fuel expense | **644.4** | (6.9) | 692.5 | 1.6 | 681.9 |
| Purchased power expense | **78.9** | 10.5 | 71.4 | 10.5 | 64.6 |
| Total fuel & purchased power expense | **723.3** | (5.3) | 763.9 | 2.3 | 746.5 |
| Total operating expenses | **1,557.0** | (1.8) | 1,585.6 | 1.5 | 1,562.0 |
| Operating income | **461.3** | 5.9 | 435.4 | 12.0 | 388.5 |
| AFUDC equity | **17.2** | 63.8 | 10.5 | 66.7 | 6.3 |
| Net income | **$ 241.0** | 7.3 | $ 224.5 | 17.6 | $ 190.9 |
| *Megawatt-Hour Sales (thousands)* | | | | | |
| Residential | **9,045** | 4.5 | 8,656 | 2.2 | 8,470 |
| Commercial | **6,301** | 2.6 | 6,142 | 0.9 | 6,090 |
| Industrial | **1,870** | (1.6) | 1,901 | (6.2) | 2,026 |
| Other | **1,791** | (2.0) | 1,827 | (0.2) | 1,832 |
| Total retail | **19,007** | 2.6 | 18,526 | 0.6 | 18,418 |
| Sales for resale | **115** | (55.5) | 259 | 16.7 | 222 |
| Total energy sold | **19,122** | 1.8 | 18,785 | 0.8 | 18,640 |
| Retail customers—(thousands) | | | | | |
| Average | **718.7** | 1.8 | 706.2 | 1.6 | 694.7 |
| Retail net energy for load | **20,103** | 4.1 | 19,315 | 0.7 | 19,178 |

**Operating Revenues**

In 2015, retail MWh sales, measured on a billing cycle basis as shown in the table above grew 2.6% from 2014 levels. Sales in 2015 reflected warmer than normal second and fourth quarter weather, strong customer growth and a stronger local economy. Pretax base revenue was more than $37 million higher than in 2014, including approximately $8 million of higher pretax base revenue as a result of the base rate increases effective Nov. 1, 2014 and 2015, described above. Total net energy for load was 4.1% higher than in 2014. Higher energy sales were driven by more favorable weather in 2015 than in 2014. In 2015, total degree days in Tampa Electric's service area were 12% above normal and 17% above 2014.

In 2014, retail MWh sales, on the same basis as discussed above, grew 0.6% from 2013. Sales in 2014 reflected generally milder weather and lower per-customer usage, partially offset by 1.6% customer growth and improvements in the local economy. Pretax base revenue, which included $50.0 million of higher revenue as a result of the base rate settlement described above, was approximately $62.0 million higher than in 2013. In 2014, total retail net energy for load increased 0.7%, compared to 2013. In 2014, total degree days in Tampa Electric's service area were 4% below normal, and 3% below 2013, reflecting generally milder weather throughout the year.

Tampa Electric is not a major participant in the wholesale market because it uses its own generation to serve its retail customers rather than selling into the wholesale market. In 2015, gross revenues from wholesale sales, which includes fuel that is a pass-through cost, was less than 1% of total revenues and has averaged less than 2% of Tampa Electric's total revenue over the past three years. Sales for resale decreased 55.5% in 2015 due to the availability of low-cost natural gas fired generation in the state mitigating the need for Tampa Electric's generating resources. Sales for resale increased 16.7% in 2014 due to weather-related sales early in the year.

**Customer and Energy Sales Growth Outlook**

The Florida economy has continued to grow, as evidenced by success in local economic development activities, by job growth, and by improvements in the new housing construction market, which has been a major driver of growth in the Florida economy for many years (see the **Risk Factors** section). In 2015, there was an almost 20% increase in new single family home building permits in Tampa Electric's service area. In general, economists are forecasting a continued improvement in the state and local economies in 2016 and beyond. 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. The 2016 forecast used by Tampa Electric reflects a continuation of the average customer growth at or slightly better than that was experienced in 2015. In 2016, weather-normalized retail energy sales to residential, commercial and non-phosphate industrial customers are expected to grow at a rate about 0.3% to 0.5% below the rate of customer growth.

Longer-term, assuming continued economic growth and business expansion, Tampa Electric expects average annual customer growth of more than 1.8% and weather-normalized average retail energy sales growth at a rate about 0.3% to 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, 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 2015. The Tampa metropolitan area added almost 39,000 new jobs in 2015 after adding 14,000 new jobs in 2014. In both years, job growth was concentrated in business and other services. The total nonfarm employment in the Tampa metropolitan area increased 3.1% in 2015 following a 1.2% increase in 2014. The local Tampa area unemployment rate decreased to 4.3% at the end of 2015 compared with 5.6% at year-end 2014 and 6.3% at year-end 2013. The Tampa area year-end 2015 unemployment rate was below the state of Florida's unemployment rate of 5.0%, and the national unemployment rate also at 5.0%.

**Operating Expenses**

Total pretax operating expense was 1.8% lower in 2015, driven primarily by lower fuel expense partially offset by higher O&M expense. O&M expenses, excluding all FPSC-approved cost-recovery clauses, increased $5.4 million in 2015, reflecting higher costs to safely and reliably serve customers partially offset by lower employee-related expenses.

Total pretax operating expense was 1.5% higher in 2014, driven primarily by higher fuel and purchased-power expense and depreciation and amortization partially offset by lower O&M expense. Excluding all FPSC-approved cost-recovery clause-related expense, O&M expense decreased $1.0 million in 2014 reflecting lower employee-related costs, including pension expense, and the elimination of the storm damage reserve accrual, partially offset by higher costs to operate and maintain the system.

In 2015 and 2014, depreciation and amortization expense increased $5.0 million and $6.0 million, respectively, reflecting additions to facilities to serve customers. In 2016, depreciation expense is expected to increase at levels similar to those experienced in 2015 and 2014.

Excluding all FPSC-approved cost-recovery clause-related expense, O&M expense in 2016 is expected to be lower than 2015, due to lower employee-related costs and the impact of synergies in Florida as a result of the NMGC integration.

**Fuel Prices and Fuel Cost Recovery**

In November 2015, the FPSC approved cost-recovery rates for fuel and purchased power, capacity, environmental and conservation costs for 2016. The rates include the expected cost for natural gas and coal in 2016, and the net over-recovery of fuel, purchased power and capacity clause expense.

Total fuel cost decreased in 2015, due to increased lower-cost natural gas-fired generation and lower costs for natural gas and coal. Purchased-power expense increased in 2015 due to higher volumes of energy purchased from others. Delivered natural gas prices decreased 23% in 2015 due to abundant supplies of natural gas from on-shore domestic natural gas produced from shale formations, and storage inventories above historic averages. Gas prices had increased 9% in 2014 as a result of cold winter weather. Delivered coal costs decreased 4.0% in 2015. The average coal and natural gas costs were $3.34/MMBTU and $4.34/MMBTU, respectively, in 2015, compared with $3.48/MMBTU and $5.68/MMBTU, respectively, in 2014.

Full-year Henry Hub natural gas futures as traded on the NYMEX and various forecasts for natural gas prices indicate that natural gas prices are expected to be in the $2.50 to $3.00/MMBTU range in 2016, and between $3.00 and $3.25 in 2017, both of which are above current price levels. Current natural gas prices reflect high storage levels due to a mild start to the winter heating season and low-cost production from shale basins in the U.S. Compared to 2015, delivered coal prices are expected to remain about the same in 2016.

**Energy Supply**

Tampa Electric's generation increased in 2015 to meet higher energy sales. Purchased power increased due to the availability of low cost natural gas-fired generation in Florida.

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 an important component in Tampa Electric's fuel mix due to the baseload units at the Big Bend Power Station and the coal gasification unit, Polk Unit 1. Tampa Electric's solid-fuel energy generation was 48% of its total system output in 2015, compared to being approximately 96% of its output in 2001.

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. Upon completion of the Polk 2-5 combine-cycle conversion project, Tampa Electric will have the ability to shift the generation mix to a higher percentage of energy from natural gas depending on cost and potential GHG regulation (see the **Environmental** section).

**Solar Initiatives**

In 2015, Tampa Electric announced plans for a 23-MW utility-scale solar photo voltaic project to be installed at Tampa Electric's Big Bend Station. This is the largest solar project in the Tampa Bay area, consisting of more than 70,000 solar panels on 125 acres of land owned by Tampa Electric. Upon completion, it will have the capacity to power more than 3,500 homes. In 2015, Tampa Electric completed the construction of a 2-MW solar photo voltaic energy installation at TIA, which is Tampa Electric's first large-scale solar facility. At 2 MW, the solar panels at TIA produce enough electricity to power up to 250 homes. Tampa Electric owns the solar photo voltaic array, and the electricity it produces goes to the grid to benefit all Tampa Electric customers, including the airport. Tampa Electric anticipates developing additional similarly sized small-scale solar photo voltaic installations and we seek opportunities for additional utility-scale installations.

In addition, Tampa Electric has installed 2,135 KW of solar panels to generate electricity from the sun at eight community sites including two schools, Tampa Electric's Manatee Viewing Center, the Museum of Science and Industry, Tampa's Lowry Park Zoo, the Florida Aquarium, and LEGOLAND Florida.

In Florida, a constitutional amendment was proposed that would allow the sale of up to 2 MW of power direct to other customers from rooftop solar panels, potentially bypassing the utility. The Florida Supreme Court ruled that the amendment meets constitutional and statutory requirements to appear on the ballot, however supporters were unable to gather and certify the required number of signatures by the deadline to have it placed on the ballot in 2016. Supporters indicate that they plan to try to have the amendment on the ballot in 2018. Legislation has been proposed for consideration in the 2016 Florida legislative session that essentially mirrors the intent of the constitutional amendment.

A second Florida constitutional amendment regarding solar power generation is proposed for the 2016 ballot that would establish a right for consumers to own or lease solar equipment installed on their property to generate electricity for their own use. State and local governments would retain the ability to protect consumer rights and public health and safety and ensure that consumers that do not choose to install solar are not required to subsidize the costs of backup power and electric grid access for those that do. The amendment has been filed with the Florida Supreme Court and a ruling related to its qualification to appear on the ballot is pending. Backers of the proposed amendment have gathered and certified the required number of signatures to have it on the 2016 ballot, assuming the Florida Supreme Court determines that it meets the constitutional and statutory requirements to appear on the ballot.

**Polk Power Station Units 2 – 5 Combined Cycle Conversion**

In 2012, 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 2016 will support construction, start-up, testing and pre-commissioning activities. (See the **Capital Expenditures** and **Regulation** sections.)

**PGS**

**Operating Results**

In 2015, PGS reported net income of $35.3 million, compared with $35.8 million in 2014. Results reflect a 2.1% higher average number of customers and lower therm sales to residential customers due to mild winter weather. Higher commercial sales volumes were driven by a strong economy and an almost 30% increase in therms sold to CNG vehicle fleets. Sales to power generation customers increased due to higher state-wide electricity demand due to warmer than normal second and fourth quarter weather. Off-system sales increased due to weather related power demand, coal to gas switching by power generators, and pipeline transportation constraints in some areas of the state. Non-fuel O&M expense was $1.9 million higher than in 2014, driven by higher operating costs, partially offset by lower employee-related costs, primarily due to the level of short-term incentive accruals for all employees in 2015 compared to 2014. O&M expense in 2014 reflected a first-quarter recovery of $1.6 million of costs incurred in connection with a 2010 outage incident. Depreciation and amortization expense increased slightly due to normal additions to facilities to serve customers.

In 2015, total throughput for PGS was almost 1.8 billion therms, up 14% from 2014 levels due to the higher volumes transported for power generation customers and higher off-system sales. Industrial and power generation customers represented approximately 59% of annual therm volume, commercial customers used approximately 27%, approximately 9% was sold off-system, and the remainder was consumed by residential customers.

Residential customers comprised almost 35% of total revenues in 2015, down from 36% of total revenues in 2014 due to lower weather driven sales. New residential construction, which includes natural gas and conversions of existing residences to natural gas, increased in 2015 as the economy and the housing market in select markets in Florida rebounded.

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. Therms sold to CNG stations increased almost 30% in 2015 to 19.8 million therms. Currently, there are 42 CNG fueling stations connected to the PGS system serving over 1,400 vehicles of various sizes. In 2016, the number of vehicles already converted or committed to conversion will consume almost 22 million therms annually, the equivalent consumption of more than 94,000 typical Florida residential customers. Additional stations are expected to be added in 2016, driven by attractive economics, even in the current low-oil price environment, and by lower emissions profile of CNG vehicles. In January 2016, PGS placed its first owned CNG filling station in service, and the cost of this station will be recovered over time through a special rate approved by the FPSC.  CNG conversions 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)* | ***2015*** | *% Change* | *2014* | *% Change* | *2013* |
|---|---|---|---|---|---|
| Revenues | **$ 407.5** | 2.0 | $ 399.6 | 1.6 | $ 393.5 |
| Cost of gas sold | **135.8** | (0.9) | 137.0 | (3.9) | 142.6 |
| Operating expenses | **201.1** | 5.6 | 190.5 | 5.2 | 181.1 |
| Operating income | **70.6** | (2.1) | 72.1 | 3.3 | 69.8 |
| Net income | **$ 35.3** | (1.4) | $ 35.8 | 3.2 | $ 34.7 |
| Therms sold – by customer segment | | | | | |
| Residential | **74.9** | (7.3) | 80.8 | 8.6 | 74.4 |
| Commercial | **470.8** | 2.2 | 460.5 | 5.1 | 438.1 |
| Industrial | **289.0** | 5.4 | 274.3 | 0.8 | 272.0 |
| Off-system sales | **166.4** | 98.1 | 84.0 | (41.3) | 143.1 |
| Power generation | **758.3** | 17.8 | 643.5 | (13.5) | 744.4 |
| Total | **1,759.4** | 14.0 | 1,543.1 | (7.7) | 1,672.0 |
| Therms sold – by sales type | | | | | |
| System supply | **268.7** | 38.3 | 194.2 | (22.2) | 249.5 |
| Transportation | **1,490.7** | 10.5 | 1,348.9 | (5.2) | 1,422.5 |
| Total | **1,759.4** | 14.0 | 1,543.1 | (7.7) | 1,672.0 |
| Customer (thousands) – average | **361.2** | 2.1 | 353.9 | 1.9 | 347.4 |

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 2015, approximately 23,300 out of 37,600 of PGS's eligible non-residential customers had elected to take service under this program.

**PGS Outlook**

In 2016, PGS expects customer growth at rates in line with those experienced for the full year in 2015, reflecting its expectations that the housing markets in many areas of the state that it serves will continue to grow. Assuming normal weather, therm sales to weather-sensitive customers, especially residential customers, are expected to increase in 2016 at rates in line with customer growth. Excluding all FPSC-approved cost-recovery clause-related expenses, O&M expense in 2016 is expected to be slightly lower than in 2015, as higher costs to operate and maintain the system and to reliably serve customers are offset by lower employee-related costs and the impact of synergies in Florida as a result of the NMGC integration. Depreciation expense is expected to be higher due to normal additions to facilities to 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 2016, PGS expects capital spending to support residential and commercial customer growth, system expansion to serve large commercial and industrial customers, continued interest in conversion of vehicle fleets to CNG and continued replacement of cast iron and bare steel pipe.

The current rate of new residential development in Florida has recovered significantly since the bottom of the economic recession. Complementing the renewed residential construction is the PGS business model for system expansion that evolved during the economic downturn to focus on extending the system to serve large commercial or industrial customers that are currently using petroleum or propane as fuel. The current low natural gas prices and the projections that natural gas prices are going to remain low into the future, and the lower emissions levels from using natural gas compared to other fuels, make it attractive for these customers to convert from other fuels even in the current low oil-price environment.

**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 through 77 interconnections (gate stations) and through an interconnection with its affiliate pipeline company serving PGS's operating divisions throughout the state.

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.

**NMGC**

NMGC reported net income of $24.1 million in 2015. Results reflected 0.7% higher average number of customers, and fourth quarter weather that resulted in degree days 5.5% below normal but 1.4% above 2014 levels, partially offset by much milder than normal winter weather in the first quarter. O&M expense was lower than in the 2014 period from acquisition synergies and a focus on cost control. Results included $2.7 million of pretax rate credits to customers. Net income of $10.5 million in 2014 reflects a partial year beginning with the Sept. 2, 2014 date of acquisition. NMGC's results for the final four months of 2014, post-closing, reflected the normal seasonal earnings pattern with strong financial results for the fourth quarter.

NMGC, headquartered in Albuquerque, is New Mexico's largest regulated local natural gas distribution company. It provides natural gas service to more than 516,000 customers, primarily residential, in 23 of New Mexico's 33 counties with a service area that encompasses nearly 60% of New Mexico's population. With 69% of its customers in the Central Rio Grande Corridor, NMGC serves one of the fastest-growing regions in the state. NMGC's major non-residential customers include military installations, power generators, computer chip makers, food processors, universities, refineries, wallboard manufacturers, government research facilities, and mining facilities.

The NMGC system is comprised of approximately 10,200 miles of distribution mains and 1,600 miles of high pressure transmission pipelines connecting the NMGC system in New Mexico. There is no cast iron pipe in the system and there are no environmental liabilities associated with manufactured gas plant sites.

NMGC operates in a state that has historically grown at rates above the national average. The acquisition provides us the opportunity to bring the natural gas marketing and development skills developed by PGS in Florida to New Mexico to grow NMGC.

**NMGC Base Rates**

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC's base rates by approximately $34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on Jan. 31, 2012, revising, among other things, base rates for all service provided on or after Feb. 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC's base rate revenue by approximately $21.5 million on a normalized annual basis. The monthly residential customer access fee increased from $9.59 to $11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017. In addition, under the order, NMGC provided $2.0 million of pretax credits on customer bills for the first 12-month period post-closing, effective Oct. 1, 2014, and beginning Oct. 1, 2015 is providing $4.0 million of pretax credits to customers in each subsequent 12-month period until new base rates are effective,( see **Note 21** to the **TECO Energy Consolidated Financial Statements**.)

**NMGC Operating Results**

The table below provides a summary of NMGC's 2015 and 2014 revenue and expenses since the closing of the acquisition in September 2014.

**Summary of Operating Results**

| *(millions)* | *For the years ended Dec. 31* 2015 | % Change(1) | 2014(1) |
|---|---|---|---|
| Revenues | **$ 316.5** | N/M | $ 137.5 |
| Cost of gas sold | **136.2** | N/M | 72.9 |
| Operating expenses | **128.2** | N/M | 43.0 |
| Operating income | **52.1** | N/M | 21.6 |
| Net income | **$ 24.1** | N/M | $ 10.5 |
| | | | |
| Therms sold – by customer segment (2) | | | |
| Residential | **291.2** | 2.4 | 284.4 |
| Commercial | **104.4** | (4.2) | 108.9 |
| Industrial | **2.5** | (16.7) | 3.0 |
| Off system sales | **1.2** | (71.8) | 4.2 |
| Transportation - on system | **328.7** | (0.3) | 329.7 |
| Transportation - off system | **47.2** | 0.5 | 47.0 |
| Total | **775.2** | (0.3) | 777.2 |
| Therms sold – by sales type | | | |
| System supply | **399.3** | (0.3) | 400.5 |
| Transportation | **375.9** | (0.2) | 376.7 |
| Total | **775.2** | (0.3) | 777.2 |
| Customer (thousands) – average | **516.1** | 0.7 | 512.6 |

(1) Year-over-year financial comparisons are not meaningful due to only four months of ownership in 2014.
(2) The full period information presented for 2014 is for comparative purposes only, as TECO Energy's ownership began on the acquisition date of Sept. 2, 2014.

The actual cost of gas and upstream transportation purchased and resold to end-use customers is recovered through a PGAC. This charge may be adjusted monthly as allowed by the NMPRC (see the **Regulation** section).

NMGC is required to provide transportation-only services for all customer classes. As a result, NMGC receives its base rates for distribution gas delivery services regardless of whether a customer elects transportation-only service or continues as a customer of NMGC's gas commodity sales service. As of Dec. 31, 2015, NMGC had approximately 4,100 transportation-only customers and approximately 512,000 gas commodity sales service end-use customers. Transportation-only volume represented 48.5% of total system throughput, and 6.3% of total revenue for 2015.

**NMGC Outlook**

In 2016, NMGC expects customer growth rates slightly better than those experienced in 2015, reflecting its expectations that the New Mexico economy will grow. Assuming normal weather, therm sales are expected to essentially track customer growth. As a condition of the August 2014 NMPRC order approving the acquisition, NMGC provided $2.0 million of pretax credits on customer bills for the first 12-month period post-closing, effective Oct. 1, 2014, and $4.0 million of credits will be provided to customers in each subsequent 12-month period until new base rates are effective. Depreciation expense is expected to increase from continued capital investments in facilities to reliably serve customers.

**NMGC Gas Supplies**

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

**OTHER (net)**

The 2015 GAAP Other – net cost from continuing operations was $59.2 million, compared with $64.4 million in 2014. The full 2015 GAAP cost for Other – net was $57.3 million compared with $58.4 million in 2014, including net benefits of $1.9 million and $6.0 million, respectively, associated with discontinued operations. The 2015 non-GAAP cost from continuing operations for Other – net was $44.2 million, which excluded $13.1 million of transaction costs related to the pending Emera acquisition and $1.9 million of NMGC integration-related costs, compared with $41.1 million in 2014, which excluded $16.6 million of NMGC acquisition and integration-related costs, and net consolidated state deferred tax balance adjustments of $6.7 million. Cost drivers in 2015 included $3.1 million of interest at New Mexico Gas Intermediate (the parent company of NMGC), $2.8 million of interest previously allocated to TECO Coal that was offset by lower interest expense from refinancing at TECO Finance, and a $2.9 million tax expense related to long-term incentive compensation shares that vested below target levels.

In 2014, the cost from continuing operations for Other (net) was $64.4 million, compared with $36.9 million in 2013. The non-GAAP cost from continuing operations was $41.1 million in 2014, which excludes $16.6 million of NMGC acquisition- and integration-related costs and $6.7 million of net consolidated deferred income tax balance adjustments to reflect the pending sale of TECO Coal and the NMGC acquisition, compared with $30.6 million in 2013, which excluded $6.2 million of NMGC acquisition-related costs. The higher non-GAAP cost in 2014 reflects $1.4 million of NMGI interest expense, $1.0 million of interest expense previously allocated to TECO Coal, $3.5 million of labor and other unallocated costs, and $3.1 million of tax items, including offsets at Parent to tax benefits at Tampa Electric.

The segment data in **Note 14** to the **TECO Energy Consolidated Financial Statements** presents “Other” and “Eliminations” as separate segments. The discussion above nets the two segments.

**DISCONTINUED OPERATIONS**

As a result of our Board of Directors authorizing us to enter into negotiations for the sale of TECO Coal, effective in the third quarter of 2014 it was classified as asset held for sale and its results for all periods reported as discontinued operations.

The sale of TECO Coal closed in September 2015. The 2015 loss of $67.7 million recorded in discontinued operations reflects TECO Coal’s operating results prior to its sale, net impairment charges of $50.8 million, and a $7.7 million charge related to black-lung liabilities. Discontinued Operations included net benefits of $1.9 million recorded in Other (net).

In 2014, discontinued operations resulted in a loss of $76.0 million comprised of the full-year operating results, $76.4 million of after-tax impairment charges and tax valuation allowances based on a sales price specified under a sales agreement entered into in October, and net benefits of $6.0 million recorded in the Other segment, relating to taxes and the 2012 sale of TECO Guatemala. Discontinued Operations included net benefits of $6.0 million in 2014 recorded in Other (net).

TECO Guatemala Holdings (TGH), a wholly owned subsidiary of TECO Energy until 2012, had subsidiaries with interests in independent power-generating projects in Guatemala. In 2012, TGH sold all of its equity interests in the Alborada and San José power stations, and related solid fuel handling and port facilities in Guatemala.

While TECO Energy and its subsidiaries no longer have assets or operations in Guatemala, TGH has retained its rights under an arbitration claim against the Republic of Guatemala under the Dominican Republic Central America – United States Free Trade Agreement (DR – CAFTA). See **Note 12** to the **TECO Energy Consolidated Financial Statements**.

**OTHER ITEMS IMPACTING NET INCOME**

**Other Income (Expense)**

Other income (expense) of $20.8 million in 2015 and of $11.0 million in 2014 included miscellaneous services at the utilities such as lightning surge protection equipment.

AFUDC-equity at Tampa Electric, which is included in Other income (expense), was $17.4 million, $10.5 million, and $6.3 million in 2015, 2014 and 2013, respectively. AFUDC is expected to increase in 2016 primarily due to the spending related to the Polk Units 2 – 5 conversion project (see the **Liquidity, Capital Resources** section).

**Interest Expense**

In 2015, interest expense, excluding AFUDC-debt, was $195.1 million compared to $176.4 million in 2014 and $165.0 million in 2013. In 2015, interest expense increased due to the addition of NMGC and NMGI debt upon the acquisition in September 2014, and additional borrowings at TEC to support its capital spending program (see **Financing Activity** section).

Interest expense is expected to increase in 2016, reflecting increased borrowing at Tampa Electric to support the construction of the Polk Power Station Units 2 – 5 conversion, partially offset by the expected refinancing of the $250 million of 4.0% TECO Finance notes at maturity in the spring of 2016 at lower interest rates.

**Income Taxes**

The provision for income taxes from continuing operations increased in 2015, primarily due to higher pre-tax income. The provision for taxes was lower in 2014, primarily due to lower pre-tax income. Income tax expense as a percentage of income from continuing operations before taxes was 39.2% in 2015, 40.2% in 2014 and 37.4% in 2013. We expect our 2016 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, and payments (refunds) related to prior years' audits totaled $14.5 million, $2.9 million and $1.8 million in 2015, 2014 and 2013, respectively. The 2015 cash tax payments are related to amended federal income tax returns.

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 include a similar level of AMT, and various state taxes. As a result of bonus depreciation enacted under several economic stimulus laws since 2008, the Final Tangible Property Regulations on repair expenditures released in 2013, and the additional bonus depreciation allowed under the Protecting Americans from Tax Hikes Act ("PATH") enacted on Dec. 18, 2015, we currently expect to utilize these NOL carryforwards primarily in the 2016 through 2022 period. Beginning in 2022, we also expect to start using our more than $214 million of AMT carry-forwards to limit future cash tax payments for federal income taxes to the level of AMT. We currently project minimal cash tax payments through 2021.

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, 2015 consolidated liquidity and cash balances, the cash balances at the operating companies and Parent, and amounts available under the TECO Energy/Finance, TEC and NMGC credit facilities.

**Balances as of Dec. 31, 2015**

| *(millions)* | Consolidated | TEC | NMGC | TECO Finance Parent/other |
|---|---|---|---|---|
| Credit facilities | $ 900.0 | $ 475.0 | $ 125.0 | $ 300.0 |
| Drawn amounts/LCs | 249.2 | 61.5 | 24.7 | 163.0 |
| Available credit facilities | 650.8 | 413.5 | 100.3 | 137.0 |
| Cash and short-term investments | 23.8 | 9.1 | 7.7 | 7.0 |
| Total liquidity | $ 674.6 | $ 422.6 | $ 108.0 | $ 144.0 |

**Cash from Operations**

In 2015, consolidated cash flow from operations was $610 million, compared to $665 million in 2014. Cash from operations in 2015 reflects strong operating results from TEC, offset by higher working capital, funding of the SERP obligation following the signing of the Merger Agreement with Emera and costs associated with the Emera transaction. Cash from operations in 2015 and 2014 reflect pension contributions of $55 million and $48 million, respectively.

In 2015, we made $14.5 million of cash tax payments for federal income taxes, (see the **Income Taxes** section). Bonus depreciation, under several economic stimulus laws enacted since 2008, has significantly reduced federal taxable income at Tampa Electric and PGS. Additionally, PATH, which was enacted on Dec. 18, 2015, is expected to provide our regulated businesses with incremental bonus depreciation deductions for tax years 2015 through 2020. 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 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. As a result of the bonus depreciation, taxable income has been reduced significantly and therefore we have utilized our NOL carryforwards less than expected. Parent cash flows have therefore been less than expected through this period, and our projection for the full utilization of the NOL carryforwards has been extended to 2022. Tampa Electric and PGS will continue to realize higher cash flows as a result of reduced cash taxes from bonus depreciation deductions, which will support their capital spending programs. We expect that Tampa Electric, PGS and NMGC will continue to realize significant cash tax savings as a result of the extension of bonus depreciation deductions and the existing tax deductions for repair expenditures provided by the Final Tangible Property Regulations released in 2013, and that Parent will realize the cash benefit of the NOL carryforwards primarily in the 2016 through 2022 period.

We expect cash from operations to increase in 2016, driven primarily by higher operating results at our Florida utilities. In November 2015, the FPSC approved fuel-adjustment and other recovery clause rates that provide for refunds to customers of estimated 2015 net over-recoveries of fuel and purchased power over 12 months beginning Jan. 1, 2016 (see the **Regulation** section). The extension of bonus depreciation will have no material impact on our consolidated cash flows since we pay minimal to no cash taxes due to our NOL carry forward position.

**Cash from Investing Activities**

Our investing activities in 2015 resulted in a net use of cash of $740 million, which reflects capital expenditures.

We expect capital spending in 2016 to be approximately $765 million (see the **Capital Expenditures** section).

**Cash from Financing Activities**

Our financing activities in 2015 resulted in net cash generation of $129 million. TEC issued $250 million of long-term debt to repay $83 million of maturing debt and for general corporate purposes (see the **Financing Activity** section). TECO Finance issued $250 million of long-term debt to repay $191 million of maturing debt and for general corporate purposes (see the **Financing Activity** section). In addition, we increased borrowings on our credit facilities by $108 million, primarily at TECO Finance. We paid $212 million in common stock dividends in 2015.

**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, 2015, our consolidated liquidity was $675 million, consisting of $423 million at TEC, $108 million at NMGC and $144 million at TECO Finance/ parent/other.

We expect sources of cash in 2016 to include cash from operations at levels above 2015, due in large part to higher operating results from our Florida utilities, debt issuance of up to $250 million and repayment of $83 million at TEC, and debt issuance of up to $400 million and repayment of $250 million of long-term debt at TECO Finance. We plan to use cash in 2016 to fund capital spending estimated at $765 million, and to pay dividends to shareholders.

We expect to continue to make equity contributions to TEC in 2016 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 2016.

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 made over the last several years for the Polk combined cycle conversion project (see the **Capital Expenditures** section). Our long-term debt maturities for TECO Finance total $250 million in 2016, $300 million in 2017, $250 million in 2018 and $300 million in 2020.

Our regulated businesses expect to utilize cash from operations and equity contributions from TECO Energy to support their capital spending programs, supplemented with incremental long-term debt and utilization of their credit facilities to maintain strong utility capital structures. Our credit facilities contain certain financial covenants (see **Covenants in Financing Agreements** section). We estimate that we could fully utilize the total available capacity under our facilities in 2016 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. 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 event TECO Energy's, TEC's or NMGC'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, 2015, we could have been required to post additional collateral or settle existing positions with counterparties totaling $26.2 million. In addition, credit provisions in long-term gas transportation agreements at our electric and gas utilities would give the transportation providers the right to demand collateral, which we estimate to be approximately $69.8 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, 2015 and 2014, the following credit facilities and related borrowings existed.

| | Dec. 31, 2015 | | | Dec. 31, 2014 | | |
|---|---|---|---|---|---|---|
| *(millions)* | Credit Facilities | Borrowings Outstanding(1) | Letters of Credit Outstanding | Credit Facilities | Borrowings Outstanding(1) | Letters of Credit Outstanding |
| TEC: | | | | | | |
| 5-year facility(2) | $ 325.0 | $ - | $ 0.5 | $ 325.0 | $ 12.0 | $ 0.6 |
| 1-year / 3-year accounts receivable facility(3) | 150.0 | 61.0 | 0.0 | 150.0 | 46.0 | 0.0 |
| TECO Energy/TECO Finance: | | | | | | |
| 5-year facility(2)(4) | 300.0 | 163.0 | 0.0 | 300.0 | 50.0 | 0.0 |
| NMGC: | | | | | | |
| 5-year facility(2) | 125.0 | 23.0 | 1.7 | 125.0 | 31.0 | 1.7 |
| Total | $ 900.0 | $ 247.0 | $ 2.2 | $ 900.0 | $ 139.0 | $ 2.3 |

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) Prior to Mar. 24, 2015, this was a 1-year facility. This 3-year facility matures on Mar. 23, 2018.
(4) 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 30.0 basis points. The weighted average interest rate on outstanding amounts payable under the credit facilities at Dec. 31, 2015 and 2014 was 1.29% and 1.16%, respectively.

TECO Energy/TECO Finance, TEC and NMGC have credit facilities with total borrowing capacities of $300 million, $475 million and $125 million, respectively. For a complete description of the credit facilities see **Note 6** to the **TECO Energy Consolidated Financial Statements.**

The table below sets forth TECO Energy/TECO Finance, TEC and NMGC maximum, minimum, and average credit facility utilization in 2015.

### 2015 Credit Facility Utilization

| *(millions)* | Maximum drawn amount | Minimum drawn amount | Average drawn amount | Average interest rate |
|---|---|---|---|---|
| TECO Energy/TECO Finance | $ 208.0 | $ 0.0 | $ 102.1 | 1.28% |
| TEC | $ 172.0 | $ 0.0 | $ 37.7 | 0.73% |
| NMGC | $ 36.0 | $ 0.0 | $ 11.2 | 1.27% |

**Significant Financial Covenants**

In order to utilize their respective bank credit facilities, TECO Energy, TECO Finance, TEC, NMGC and NMGI must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy, TECO Finance, and the other operating companies have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2015, we 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, 2015. 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, 2015 |
|---|---|---|---|
| **TEC** | | | |
| Credit facility (2) | Debt/capital | Cannot exceed 65% | 47.0% |
| Accounts receivable credit facility (2) | Debt/capital | Cannot exceed 65% | 47.0% |
| 6.25% senior notes | Debt/capital | Cannot exceed 60% | 47.0% |
| | Limit on liens (3) | Cannot exceed $700 | $0 liens outstanding |
| **NMGC** | | | |
| Credit facility (2) | Debt/capital | Cannot exceed 65% | 30.7% |
| 3.54% and 4.87% senior unsecured notes | Debt/capital | Cannot exceed 65% | 30.7% |
| **NMGI** | | | |
| 2.71% and 3.64% senior unsecured notes | Debt/capital | Cannot exceed 65% | 47.6% |
| **TECO Energy/TECO Finance** | | | |
| Credit facility (2) | Debt/capital | Cannot exceed 65% | 61.9% |

(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.

**Credit Ratings of Senior Unsecured Debt**

| | Standard & Poor's (S&P) | Moody's | Fitch |
|---|---|---|---|
| TEC | BBB+ | A2 | A- |
| NMGC | BBB+ | - | - |
| TECO Energy/TECO Finance | BBB | Baa1 | BBB |

On Oct. 27, 2014, S&P placed the issuer credit rating of TECO Energy and the senior unsecured debt rating of its subsidiaries, TECO Finance, TEC and NMGC on credit watch with positive implications, following the announcement of the October 2014 agreement to sell TECO Coal. On July 6, 2015, S&P removed the TECO Energy issuer credit rating from credit watch positive and affirmed all credit ratings after the expiration of the October 2014 agreement to sell TECO Coal. S&P also described the outlook as positive on TEC, NMGC and TECO Energy/TECO Finance. On July 17, 2015, S&P revised the outlook for TECO Energy and its subsidiaries from positive to developing and affirmed all credit ratings in response to TECO Energy's confirmation that it was exploring strategic alternatives. On Sept. 8, 2015, S&P affirmed the issuer credit rating of TECO Energy and the senior unsecured debt rating of its subsidiaries, TECO Finance, TEC and NMGC and revised the outlook to negative from developing, following the announcement of the pending Merger with Emera.

On Sept. 8, 2015, Moody's Investors Service, Inc. announced that the pending Merger with Emera had no immediate impact on the senior unsecured debt ratings of TECO Energy and subsidiaries.

On Sept. 8, 2015, Fitch Ratings affirmed the issuer default ratings of TECO Energy and the senior unsecured debt rating of its subsidiaries, TECO Finance and TEC, following the announcement of the pending Merger with Emera. On Oct. 9, 2015, Fitch Ratings affirmed the issuer default ratings of TECO Energy at BBB and TEC at BBB+ and affirmed the senior unsecured debt rating of its subsidiaries, TECO Finance and TEC. Fitch Ratings also described the ratings outlook as "Stable".

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, TEC and NMGC'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.

**Off-Balance Sheet Arrangements**

Other than the guarantee arrangements discussed in **Note 12** to the **TECO Energy Consolidated Financial Statements**, TECO Energy and its subsidiaries have no off-balance sheet arrangements. We do not believe these guarantees have or are reasonably likely to have a material effect on our financial condition or results of operations.

**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, 2015**

| | Payments Due by Period | | | | | |
|---|---|---|---|---|---|---|
| *(millions)* | *Total* | *2016* | *2017* | *2018* | *2019-2020* | *After 2020* |
| Long-term debt [1] | $ 3,836.0 | $ 333.3 | $ 300.0 | $ 554.2 | $ 350.0 | $ 2,298.5 |
| Operating leases/rentals/capacity payments [2] | 85.5 | 22.3 | 17.0 | 16.5 | 11.1 | 18.6 |
| Net purchase obligations/commitments [2] [3] | 288.0 | 222.5 | 21.5 | 9.6 | 14.4 | 20.0 |
| Interest payment obligations | 2,121.7 | 171.6 | 163.9 | 135.1 | 238.1 | 1,413.0 |
| Pension plan [4] | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Total contractual obligations | $ 6,331.2 | $ 749.7 | $ 502.4 | $ 715.4 | $ 613.6 | $ 3,750.1 |

(1) Includes debt at TECO Finance, Tampa Electric, PGS, NMGI and NMGC (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, PGS and NMGC for fuel, fuel transportation and power purchases which are recovered from customers under regulatory clauses approved by the FPSC and NMPRC (see the Regulation section).

(3) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. At the end of 2015, these commitments include Tampa Electric's outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines.

(4) Under calculation requirements of the Pension Protection Act, as of the Jan. 1, 2015 measurement date, our pension plan was essentially fully funded. Under MAP 21, we are not required to make additional cash contributions over the next five years; however we may make additional cash contributions from time to time. Future contributions 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 investment portfolio 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, 2015**

| (millions) | | Total (1) |
|---|---|---|
| Letters of credit(1) | Tampa Electric | $ 0.5 |
| | NMGC | 1.7 |
| Guarantees(1) | Fuel sales and transportation | 92.9 |
| | Letters of indemnity - coal mining permits | 90.0 |
| Total contingent obligations | | $ 185.1 |

(1) These guarantees and letters of credit renew annually and are assumed to continue to renew beyond 2020. Other than the letters of indemnity related to coal mining permits, none are expected to expire in the 2016 – 2020 period. See **Note 12** to the **TECO Energy Consolidated Financial Statements** for more information regarding the guarantees and letters of credit.

**CAPITAL INVESTMENTS**

| | | Forecast | | | |
|---|---|---|---|---|---|
| *(millions)* | *Actual 2015* | *2016* | *2017* | *2018-2020* | *2016 - 2020 Total* |
| Tampa Electric (1) | | | | | |
| Transmission | $ 30 | $ 45 | $ 30 | $ 80 | $ 155 |
| Distribution | 135 | 165 | 155 | 490 | 810 |
| Generation | 105 | 130 | 135 | 360 | 625 |
| New generation and transmission | 230 | 170 | 15 | 180 | 365 |
| Other | 70 | 60 | 35 | 100 | 195 |
| Other environmental | 20 | 5 | 25 | 70 | 100 |
| Tampa Electric total | 590 | 575 | 395 | 1,280 | 2,250 |
| Net cash effect of accruals, retentions and AFUDC | 5 | 0 | 0 | 0 | 0 |
| Tampa Electric net | 595 | 575 | 395 | 1,280 | 2,250 |
| PGS | 95 | 105 | 130 | 300 | 535 |
| NMGC | 50 | 80 | 85 | 185 | 350 |
| Other companies | 0 | 5 | 0 | 0 | 5 |
| Total | $ 740 | $ 765 | $ 610 | $ 1,765 | $ 3,140 |

(1) Individual line items exclude AFUDC-debt and equity.

TECO Energy's 2015 capital expenditures of $740 million included $595 million at Tampa Electric, excluding AFUDC debt and equity. Tampa Electric's capital expenditures in 2015 included $215 million for the Polk 2 -5 conversion to combined cycle and related transmission system improvements, $15 million for solar generation projects at Tampa International Airport and the Big Bend Power Station, $10 million for the conversion of the Big Bend Station boiler ignition system from distillate oil to natural gas, and approximately $25 million in the first year of its program to replace its Customer Information System with a state-of-the-art Customer Relationship Management and Billing System (CRMB). This CRMB system is the first step in modernizing the distribution system to enable the implementation of smart-grid technologies in the post-2016 forecast period. Tampa Electric expects to spend an additional $20 million in 2016 to complete the CRMB project. Tampa Electric also spent approximately $35 million for hurricane storm hardening for both the transmission and distribution systems, and $20 million for maintenance capital for environmental control equipment and compliance with environmental regulation. Capital expenditures in 2015 for PGS were approximately $95 million, including approximately $30 million for maintenance of the existing system, $55 million to expand the system and support customer growth, and $10 million for replacement of cast iron and bare steel pipe. NMGC capital expenditures of $50 million included amounts to support customer growth, system reliability, facilities and equipment to safely and reliably operate the system, and investments in computer systems and technology required to successfully integrate NMGC financial and related systems with TECO Energy systems.

TECO Energy estimates capital spending to be $765 million for 2016 and approximately $2.4 billion during the 2017 to 2020 period. As described below, this forecast includes $135 million for Tampa Electric's Polk 2 – 5 conversion to combined cycle, including transmission system improvements to support the increased plant output and $35 million for the 23 MW solar voltaic project at Tampa Electric's Big Bend Station. The forecast includes $195 million for future generating capacity additions, which currently include conventional natural gas fired combustion turbines, see the discussion below related to new generation and transmission.

For 2016, Tampa Electric expects capital spending to be $575 million. For the transmission and distribution systems, Tampa Electric expects to spend $210 million in 2016, including approximately $155 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 $130 million include approximately $20 million for repair and refurbishments of CTs under long-term agreements with equipment manufacturers, approximately $50 million for generating system reliability in 2016 and advance purchases for 2017 unit outages. The capital expenditure forecast includes $35 million, included in the New Generation category, for a 23 MW solar array that Tampa Electric will build, own and operate at the Big Bend Power Station. Included in 2016 capital expenditure forecast is $20 million to complete the CRMB project described above.

In the 2017 to 2020 period, Tampa Electric expects to spend approximately $500 million annually to support normal system growth and reliability, environmental compliance and improvements to facilities 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 more than $90 million to support generating unit availability and reliability; average annual expenditures of almost $25 million for environmental compliance; average annual expenditures of more than $35 million for general infrastructure and facilities; average annual expenditures of approximately $30 million for transmission and distribution system storm hardening; and approximately $145 million annually for transmission and distribution system capacity improvements to meet expected stronger customer growth and reliability. Included in this period is average annual capital spending of approximately $25 million to implement the new technology required to modernize the distribution system and install automated metering equipment that is typically associated with "smart grid" technology.

The capital spending forecast for Generation, shown in the table above, includes approximately $120 million for modifications to the Polk Unit 1 gassifier to produce a high value by-product. Spending on this project and any other revenue enhancing projects must be justified by an internal economic analysis that demonstrates a net benefit.

Tampa Electric's capital spending forecast includes final amounts related to the conversion of the Polk Units 2 – 5 from peaking service to combined cycle with a January 2017 in-service date. 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 2016 capital expenditures support the completion of the construction on the power plant and the related transmission system upgrades, start-up testing and precommissioning activities.

New generation and transmission for the 2017 – 2019 period includes approximately $195 million based on the assumption of a simple cycle peaking unit scheduled to be in-service in early 2020, and continued success in developing additional solar generation projects similar to the 2 MW project at TIA. Tampa Electric recognizes that the proposed Clean Power Plan (see the **Environmental** section) favors generating resources with lower or no carbon emissions. Tampa Electric may meet the need for additional generating capacity in 2020 with a conventional peaking unit or some combination of conventional generation distributed generation and/or renewable resources such as solar.

Capital expenditures for PGS are expected to be about $105 million in 2016 and $430 million during the 2017 to 2020 period. Included in these amounts is an average of approximately $65 million annually for projects associated with customer growth and system expansion. The PGS capital expenditure forecast includes amounts related to constructing pipelines in the Northeast Florida area to support new Liquefied Natural Gas (LNG) terminals for export and fueling vessels that are dependent on project economics. 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 more expensive on a cost per MMBTU basis. In the current low oil price environment, the economics of converting to natural gas remain attractive for the long term, and natural gas has lower $CO_2$ emissions than petroleum based fuels that are attractive to users.

The NMGC capital expenditure forecast shown above includes approximately $30 million annually for ongoing renewal, replacement and system safety and approximately $10 million annually for system expansion to support growth. Capital expenditures in 2016 include approximately $35 million for a transmission pipeline "looping" project to enhance system reliability and capacity for anticipated growth. The forecast beyond 2016 includes approximately $25 million for software and systems upgrades, which are components of the integration plans with TECO Energy. The NMGC capital spending forecast in 2017 and 2018 include amounts for additional transmission system looping projects to enhance system reliability and capacity. NMGC's capital expenditure forecasts may increase in future years as marketing, economic development and system expansion plans are further developed in the integration process.

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, PGS and NMGC; 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 and NMGC systems. 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 2015 consolidated capital structure was 62% debt and 38% common equity. Our year-end 2014 consolidated capital structure was 59% debt and 41% common equity. The debt-to-total-capital ratio had improved significantly between 2007 and 2013, primarily due to the repayment of more than $1.0 billion of Parent and Parent-guaranteed debt during that period. The consolidated debt-to-total capital ratio increased in 2015 due to higher debt balances and impairment charges taken related to the sale of TECO Coal, and increased in 2014 due to debt issued to finance the NMGC acquisition and higher debt balances at TEC. At Dec. 31, 2015, TEC's year-end capital structure was 47% debt and 53% common equity.

In 2015 and 2014, we raised $7.3 million and $302.3 million, respectively, of equity through the exercise of stock options and through an underwritten public offering of our common stock in July 2014. The 2014 equity offering was in connection with our acquisition of NMGC.

NMGC acquisition-related financing in 2014 included the issuance of $200 million of debt at NMGI and $70 million of debt at NMGC, proceeds from which were used to repay existing debt of $219 million and to fund the transaction, costs and expenses.

## 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, 2015, we had a net deferred income tax liability of $569.9 million, attributable primarily to property-related items, AMT credit carryforwards and net operating loss carryforwards. 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, 2015, other than certain state related tax benefits, will be realized in future periods. See further discussion of valuation allowance in **Note 4** to the **TECO Energy Consolidated Financial Statements**.

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**

We sponsor a defined benefit pension plan (pension plan) that covers substantially all employees. In addition, we have a fully-funded non-qualified, non-contributory supplemental executive retirement benefit plan available to certain members of senior management. We believe 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, liabilities, AOCI and results of operations; and 2) changes in assumptions could change the annual pension funding requirements, which could have a significant impact on the company's annual cash requirements.

Several statistical and other factors, which attempt to anticipate future events, are used in calculating the expense and liability related to these plans. Key factors include assumptions about the expected rates of return on plan assets, discount rates and mortality rates. We determine these factors within certain guidelines and with the help of external consultants. We consider market conditions, including changes in investment returns and interest rates, in making these assumptions.

Pension plan assets (plan assets) are invested in a mix of equity and fixed-income securities. The 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 that holds the plan assets. Due to the continued low interest-rate environment, we reduced our expected return on assets from 7.50% used in 2013 to 7.25% at our Jan. 1, 2014 valuation and to 7.00% at our Aug. 31, 2014, and Oct. 31, 2014, remeasurements. No such reduction was deemed necessary in 2015. We will continue to monitor the above-listed factors to determine whether it is appropriate to change the expected return on assets in the future. Actual earned returns in 2015 were 3.5%.

The discount rate assumption used to determine the 2015 benefit expense and Dec. 31, 2015, benefit obligation was based on a cash-flow matching technique developed by our outside actuaries and a review of current economic conditions. This technique constructs hypothetical bond portfolios using high-quality (AA or better by Moody's) corporate bonds available from the Bloomberg Finance LP 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.

In October 2014, the Society of Actuaries (SOA) released its final report of the RP-2014 mortality tables. The SOA tables incorporate the results of the SOA's study of actual mortality of pension plans from 2004 – 2009. However, concerns have been raised over excluded data, as the bulk of the study came from five very large plans that may not be indicative of the general population, and the potential that the study was overly optimistic in projecting results from 2006 data (the central year of data in the study) to 2014. As a result of these concerns, the SOA conceded that it may be appropriate to use other projection scales.

We reviewed our actuary's independent study to assess whether the RP -2014 base table was appropriate for its clients in various industries. The study found that the changes observed by the SOA for the base mortality rate were appropriate on a nationwide basis, including the utility sector (although other industries exhibited more significant variations). However, based on data published by the Social Security Administration (SSA), the study concluded that the SOA's projection of the 2006 data to 2014 was potentially overly optimistic and that other mortality projection scales could also be considered reasonable. The projection scale analysis focused on ages between 65 and 84, since that population is key in determining pension plan costs, and found that the ultimate annual improvement rate of 1.00% used in the SOA tables was more optimistic than the 0.75% rate published by the SSA in its report "The Long-Range Demographic Assumptions for the 2014 Trustees Report" for ages between 65 and 84. Additionally, the SOA table uses a 20-year grade-down period to the ultimate assumed rate of improvement. However, a 10-year grade-down period is more consistent with recent experience and with the historical pattern of more rapid changes in the rate of mortality improvement. The SSA has provided actual data from the first three years of the SOA grade-down period to be 1.59% compared to 2.43% for this period in the SOA table.

Therefore, we determined the SOA mortality tables are not the most appropriate mortality tables to be used in valuing the company's postretirement benefit plans. Beginning with the 2014 year-end measurement, we utilize a table that is based on the SOA RP-2014 mortality but adjust it to remove the post-2007 improvement projections for our base scale. For our projection scale, we use a projection scale that utilizes the same data and methodology used in the SOA-developed projection scale but modifies it to use a 10-year grade-down period and a 0.75% ultimate annual improvement rate. We believe these tables are more appropriate and reflective of our population.

Holding all other assumptions constant, a 1% decrease in the assumed rate of return on pension plan assets would have increased 2015 after-tax pension cost by approximately $3.6 million. Likewise, a 1% decrease in the discount rate assumption would have increased 2015 after-tax pension cost approximately $2.2 million. For 2016, a 1% decrease in the discount rate assumption would result in an approximately $3.2 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 $4.0 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, President Obama 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. In August 2014, President Obama signed into law the Highway and Transportation Funding Act of 2014, which delays the phase-out of MAP-21. We plan on funding at levels above the required minimum pension contributions under MAP-21.

In addition, we currently provide certain postretirement health care and life insurance benefits for substantially all employees retiring after age 50 who meet certain service requirements. We implemented an EGWP for our 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 Patient Protection and Affordable Care Act and Health Care and Education Reconciliation Act (combined the Health Care Reform Acts), which are greater than subsidy payments previously received under Medicare Part D for our post-65 retiree prescription drug plan. As a result, we ceased receiving Medicare Part D subsidy payments beginning with the 2013 plan year. Effective Jan. 1, 2015, we changed our post-65 retiree coverage for medical benefits to a Medicare Advantage plan insured by Aetna. This will result in a lower claims cost by taking advantage of the government subsidies available for that plan.

The Health Care Reform Acts contain other provisions that may impact our obligation for retiree medical benefits, including 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. We do not currently believe the excise tax or other provisions of the Health Care Reform Acts will materially increase our postretirement benefit obligation. We will continue to monitor and assess the potential impact of the Health Care Reform Acts, including any clarifying regulations issued to address how the provisions are to be implemented, and on our 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. We determine the discount rate for the OPEB the OPEB's projected benefit cash flow. In estimating the health care cost trend rate, we consider our actual health care cost experience, future benefit structures, industry trends, and advice from our outside actuaries. We assume that the relative increase in health care cost will trend downward over the next several years, reflecting assumed increases in efficiency in the health care system and industrywide cost-containment initiatives.

Our assumed health care cost trend rate for medical costs was 7.09% during 2015 and updated to 7.05% for the Dec. 31, 2015 measurement. This rate, over time, will decrease to 4.50% in 2038 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 2015, and an estimated $0.3 million increase in 2016.

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 we believe that the assumptions used are appropriate, differences in actual experience or changes in assumptions may materially affect our financial position or results of operations.

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

**Evaluation of Assets for Impairment**

*Goodwill*

Under the accounting guidance for goodwill, goodwill is not subject to amortization. Rather, goodwill is subject to an annual (or more frequent if events and circumstances indicate a possible impairment) assessment for impairment at the reporting unit level.

Reporting units are generally determined at the operating segment level or 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. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. If an entity performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount or if an entity bypasses the qualitative assessment, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense.

Application of the goodwill impairment test requires management judgment. Significant assumptions used in these fair value analyses include discount and growth rates, rate case assumptions, utility sector market performance and transactions, projected operating and capital cash flows for the relevant business and the fair value of debt. In applying the second step (if needed), management must estimate the fair value of specific assets and liabilities of the reporting unit.

At Dec. 31, 2015, we had $408.4 million of goodwill on our balance sheet, which is reflected in the NMGC segment. This goodwill balance arose from our purchase of NMGC on Sept. 2, 2014. We performed a quantitative assessment for our annual goodwill assessment in the fourth quarter of 2015 using a weighted combination of a discounted cash flow analysis, a market multiples analysis and a comparable transaction analysis. The first step of the impairment assessment comparing the estimated fair value of NMGC to its carrying value, including goodwill, indicated no impairment of goodwill; therefore, the second step was not required.

We used both a net asset value test and an equity test in performing the first step of the assessment. The net asset value test compared the calculated fair value of NMGC to the carrying value of its net assets (calculated as total assets less non-debt liabilities). The calculated fair value was approximately 7.3% in excess of the net assets. The equity test compared the fair value of equity (calculated as the calculated fair value of NMGC less the calculated fair value of debt) to the book value of equity. The fair value of equity was approximately 10.8% in excess of the book value of equity. Assuming no other changes in assumptions, a reduction in the long-term growth rate of 40 basis points or an increase in the discount rate of 45 basis points would result in the carrying amount of NMGC to exceed its estimated fair value.

Subsequent to our assessment of the goodwill analysis, the Protecting Americans from Tax Hikes Act of 2015 was signed into law. With this legislation, NMGC cash flows through 2019 are expected to improve over what was used in the fourth quarter goodwill assessment, resulting in a larger calculated fair value over the net assets and book value of equity. Therefore, the percentages mentioned above are conservative in nature based on known and expected trends and assumptions.

Certain assumptions used to estimate the fair value of NMGC are highly sensitive to changes. Adverse regulatory actions, such as significant reductions in the allowed ROE at NMGC, or changes in significant assumptions, including growth rates, utility sector market performance and transactions, projected operating and capital cash flows from NMGC’s business, and the fair value of debt, could negatively impact goodwill in the future. See **Notes 1**, **20** and **21** to the **TECO Energy Consolidated Financial Statements** for additional information.

*Long-Lived Assets*

In accordance with accounting guidance for long-lived assets, we assess whether there has been an impairment of our long-lived assets and certain intangibles held and used when such indicators exist. We normally review all long-lived assets in the last quarter of each year to ensure that any gradual change over the year and the seasonality of the markets are considered when determining which assets require an impairment analysis. 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. Our assumptions relating to future results of operations or other recoverable amounts are based on a combination of historical experience, fundamental economic analysis, observable market activity and independent market studies. Our expectations regarding uses and holding periods of assets are based on internal long-term budgets and projections, which give consideration to external factors and market forces, as of the end of each reporting period. The assumptions made are consistent with generally accepted industry approaches and assumptions used for valuation and pricing activities.

See **Note 19** to the **TECO Energy Consolidated Financial Statements** for discussion of our treatment of impairment of long-lived assets for the year ended Dec. 31, 2015.

**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. NMGC is subject to regulation by the NMPRC. 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 and New Mexico 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**

**Revenue from Contracts with Customers**

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The standard is principle-based and provides a five-step model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In addition, the guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. This guidance will be effective for the company beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. We expect to adopt this guidance effective Jan. 1, 2018, and are continuing to evaluate the available adoption methods and the impact of the adoption of this guidance on our financial statements, but do not expect the impact to be significant.

**Presentation of Debt Issuance Costs**

In April 2015, the FASB issued guidance regarding the presentation of debt issuance costs on the balance sheet. Under the new guidance, an entity is required to present debt issuance costs as a direct deduction from the carrying amount of the related debt liability rather than as a deferred charge (i.e., as an asset) under current guidance. In August 2015, the FASB amended the guidance to include an SEC staff announcement that it will not object to a company presenting debt issuance costs related to line-of-credit arrangements as an asset, regardless of whether a balance is outstanding. This guidance will be effective for us beginning in 2016 and will be required to be applied on a retrospective basis for all periods presented. As of Dec. 31, 2015, $27.7 million of debt issuance costs, which does not include costs for line-of-credit arrangements, are included in the "Deferred charges and other assets" line item on our Consolidated Condensed Balance Sheet. The guidance will not affect our results of operations or cash flows.

**Disclosure of Investments Using Net Asset Value**

In May 2015, the FASB issued guidance stating that investments for which fair value is measured using the NAV per share practical expedient should not be categorized in the fair value hierarchy but should be provided to reconcile to total investments on the balance sheet. In addition, the guidance clarifies that a plan sponsor's pension assets are eligible to be measured at NAV as a practical expedient and that those investments should also not be categorized in the fair value hierarchy. Our pension plan has such investments as disclosed in **Note 5** to the **TECO Energy Consolidated Financial Statements**. This standard will be required for us beginning in 2016. As early adoption is permitted, we adopted the standard for our 2015 fiscal year and applied the presentation on a retrospective basis for all periods presented in the pension plan assets fair value hierarchy. The guidance did not affect our balance sheets, results of operations or cash flows.

**Measurement Period Adjustments in Business Combinations**

In September 2015, the FASB issued guidance requiring an acquirer in a business combination to account for measurement period adjustments during the reporting period in which the adjustment is determined, rather than retrospectively. When measurements are incomplete as of the end of the reporting period covering a business combination, an acquirer may record adjustments to provisional amounts based on events and circumstances that existed as of the acquisition date during the period from the date of acquisition to the date information is received, not to exceed one year. The guidance will be effective for us beginning in 2016 and will be applied prospectively. The guidance will not affect our current financial statements. However, we will assess the potential impact of the guidance on future acquisitions.

**Balance Sheet Classification of Deferred Taxes**

In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. To simplify the presentation of deferred income taxes, the new guidance requires that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet rather than be classified as current or noncurrent under current guidance. The guidance will be required for us beginning in 2017 and may be applied on a prospective or retrospective basis. As early adoption is permitted, we adopted the standard in December 2015 and applied the balance sheet presentation on a prospective basis. Therefore, prior period balance sheets were not retrospectively adjusted. The guidance did not affect our results of operations or cash flows.

**Recognition and Measurement of Financial Assets and Financial Liabilities**

In January 2016, the FASB issued guidance related to accounting for financial instruments, including equity investments, financial liabilities under the fair value option, valuation allowances for available-for-sale debt securities, and the presentation and disclosure requirements for financial instruments. We do not have equity investments or available-for-sale debt securities and we do not record financial liabilities under the fair value option. However, we are evaluating the impact of the adoption of this guidance on our financial statement disclosures, including those regarding the fair value of our long-term debt, but we do not expect the impact to be significant. The guidance will be effective for us beginning in 2018.

**Leases**

In February 2016, the FASB issued guidance regarding the accounting for leases. The objective is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with a lease term of more than 12 months. In addition, the guidance will require additional disclosures regarding key information about leasing arrangements. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. The dual model for income statement classification is maintained under the new guidance and as a result is expected to limit the impact of the changes on the income statement and statement of cash flows. This guidance will be effective for us beginning in 2019, with early adoption permitted, and will be applied using a modified retrospective approach. We are currently evaluating the impacts of the adoption of the guidance on our financial statements.

## 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 potentially responsible party (PRP) for certain superfund sites and, through its PGS division, for certain former manufactured gas plant sites. NMGC has not been designated as a PRP and has no 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 Nov. 22, 2013. Termination of the Consent Final Judgment was completed on May 6, 2015.

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 NOx 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). Cost recovery for the repowering of the Bayside Power Station was accomplished in Tampa Electric's 2008 rate case.

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 the 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 NOx. The federal appeals court reinstated CAIR in December 2008 on an interim basis. 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.

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, 2013, and ordered the reinstatement of CAIR pending the outcome of the litigation. On Aug. 21, 2012, the court vacated CSAPR entirely and remanded it back to the EPA while leaving the CAIR in place. On April 29, 2014, the U.S. Supreme Court issued an opinion reversing an Aug. 21, 2012 D.C. Circuit decision that had vacated CSAPR. Following the remand of the case to the D.C. Circuit, the EPA requested that the court lift the CSAPR stay and toll the CSAPR compliance deadlines by three years. On Oct. 23, 2014, the D.C. Circuit granted the EPA's request. Effective Jan. 1, 2015, CSAPR Phase 1 replaced CAIR. Phase 2 of the CSAPR is expected to be implemented in 2017.

**$SO_2$ National Ambient Air Quality Standards (NAAQS)**

On June 2, 2010, the EPA revised the primary $SO_2$ NAAQS by establishing a new 1-hour standard at a level of 75 parts per billion (ppb). A part of Hillsborough County north of Big Bend Station has a monitor that violates the 2010 $SO_2$ NAAQS. Although Big Bend Station did not contribute to the violation, it has potential effects on the non-attainment area based on air dispersion modeling evaluations and has committed to accept a more stringent $SO_2$ permit limit to ensure the area achieves compliance with the ambient air standards.

The next phase of the $SO_2$ NAAQS process will address all ambient $SO_2$ exceedances located outside the designated non-attainment areas. Air dispersion modeling or ambient air monitoring will be used to determine impacts to these areas beginning no earlier than 2018 but no later than 2021. Additional $SO_2$ emission reductions may be required depending on the outcome of this process.

**Hazardous Air Pollutants (HAPS) Maximum Achievable Control Technology (MACT) Mercury Air Toxics Standards (MATS)**

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 possible extensions to early 2016 or 2017 under certain specific criteria.

On June 29, 2015, the U.S. Supreme Court remanded the EPA's MATS to the U.S. District of Columbia Circuit Court (the "D.C. Circuit Court") for failing to properly consider the cost of compliance. The D.C. Circuit Court must now decide whether to vacate or stay the rule and require EPA to submit further cost benefit analysis. MATS remains in effect until the D.C. Circuit Court acts.

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 MATS 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.

**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 16.3 million tons of $CO_2$ (an increase of approximately 2%) 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, 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, the 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 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. A recent U. S. Supreme Court ruling narrowed the EPA's authority to implement this rule but the key provisions remain applicable to Tampa Electric. While this rule does not have an immediate impact on Tampa Electric's ongoing operations, GHG permitting was completed for Tampa Electric's next base load unit, the Polk Unit 2 – 5 conversion to combined cycle.

In June 2013, President Obama announced his Climate Action Plan a broad package of mostly administrative initiatives aimed at reducing GHG emissions by approximately 17% below 2005 levels by 2020. As part of the Climate Action Plan, the President directed the 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. In response to this directive, on June 2, 2014, the EPA released a comprehensive proposed rule to limit GHG emissions from existing power plants. The EPA's final rule, the Clean Power Plan, was signed by the Administrator of the EPA on Aug. 3, 2015 and sets emission performance goals that will cut GHG emissions from existing power plants by an average across all states of 32% from their 2012 levels by 2030, with an interim goal for the period from 2022 through 2029. Under the final rule, each state would have to reduce carbon dioxide emissions on a state-wide basis by an amount specified by the EPA adopting either a rate- or mass-based approach; the target amount was determined by the EPA's view of each state's options, including: making power plant efficiency upgrades; shifting from coal-fired to natural gas-fired generation; and investing in zero- and low-emitting power sources, such as renewable and nuclear energy. Under the methodology employed by the EPA , Florida has state-specific rate- and mass-based GHG targets that are in the middle of the range of goals the EPA has set for individual states. Based on the state-specific rate-based goal, generation capacity in Florida has an emission reduction goal equal to a 29% reduction in the GHG emission rate of affected electricity generating units. States are intended to have a great deal of flexibility in designing programs to meet their emission reduction targets, including the three approaches noted above or any other measures they choose to adopt, for example, energy efficiency programs. The final rule was published in the U.S. Federal Register occurred on Oct. 23, 2015. Under the rule as published, states had until September 2016 to submit initial plans to achieve their target emission reductions (subject to extension and EPA approval of the states' plans).

On Jan. 21, 2016, the U.S. Court of Appeals for the District of Columbia Circuit denied requests by 27 states and numerous trade groups for a stay that would have barred the EPA from implementing the carbon regulations for the electricity sector, but indicated that it would expedite the process for considering the lawsuits and would hear oral arguments June 2, 2016. However, on Feb. 9, 2016, the U.S. Supreme Court issued a stay against enforcement of the Clean Power Plan for the electricity sector pending resolution of the legal challenges before the U.S. Court of Appeals for the District of Columbia Circuit. The timing of the resolution of the legal challenges and the removal of the stay by the U.S. Supreme Court is uncertain, but it is likely to delay further actions by the states until 2018. Prior to the U.S. Supreme Court ruling, Florida had not begun its rulemaking process, and is currently awaiting final resolution of the legal challenges before proceeding with rulemaking. Tampa Electric is evaluating a number of potential compliance scenarios, but until there is consensus in Florida regarding a state plan it will not be possible to develop a final compliance plan. The outcome of this litigation and the rule-making process and its impact on TECO Energy's businesses is uncertain at this time; however, it could result in increased operating costs, and/or decreased operations at Tampa Electric's coal-fired plants. Depending on how the state plan is developed and implemented, the Clean Power Plan could cause an increase in costs or rates charged to customers, which could curtail sales. See **Item 1A - Risk Factors**.

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 it is uncertain if the FPSC would grant such recovery.

**Ozone**

On Sept. 30, 2015 in response to a court order, the EPA published a final rule revising the ground level ozone standard to 70 parts per billion from the previous level of 75 parts per billion. Compliance with the new standard will be the responsibility of individual states, which will provide flexibility in meeting the standards depending on the severity of each states ozone levels. States will be required to be in compliance between 2020 and 2037. Until Florida develops a compliance plan it is not possible to estimate the impact of this new standard on the operations of Tampa Electric or to estimate the cost of compliance.

**Water Supply and Quality**

The EPA's final rule under 316(b) of the Clean Water Act became effective in October 2014. This rule was initially proposed by EPA in response to citizens' lawsuits over perceived impacts to aquatic life resulting from operation of cooling water systems in the U.S. from either impingement (on intake screens) or entrainment (through condensers). 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. Neither station has historically demonstrated any significant adverse environmental impacts. Polk Power Station is not covered by this rule since it does not operate an intake on Waters of the U.S. Tampa Electric has two ongoing projects (one for Bayside and one for Big Bend) to negotiate scheduling with the regulating authority and to complete the biological, technical, and financial study elements necessary to comply with the rule. These study elements will ultimately be used by the regulating authority to determine the necessity of cooling water system retrofits for Big Bend and Bayside Power Stations. The full impact of the new regulations on Tampa Electric will depend on the outcome of subsequent legal proceedings challenging the rule, the results of the study elements performed as part of the rules' implementation, and the actual requirements established by state regulatory agencies.

EPA determined that numeric water quality standards are required in Florida to implement the Clean Water Act. On Jan. 26, 2010, EPA published proposed "Water Quality Standards for the State of Florida's Lakes and Flowing Waters." There was a long, litigious path in which EPA and FDEP both proposed criteria. Ultimately, the courts upheld the ruling that the Florida regulations meet the requirements of the Clean Water Act. Both Big Bend and Bayside Power Stations already have allocations allotted by the Nitrogen Management Consortium of the Tampa Bay Estuary Program for total nitrogen, which is the limiting nutrient for Tampa Bay. Other criteria related to streams may still directly affect Polk Power Station's cooling reservoir discharge to surface water, and 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 final EPA rule was published in the U.S. Federal Register Nov. 3, 2015 and became effective Jan. 4, 2016. The ELGs establish limits for wastewater discharges from flue gas desulfurization (FGD) processes, fly ash and bottom ash transport water, leachate from ponds and landfills containing coal combustion residuals (CCRs), gasification processes, and flue gas mercury controls. For FGD wastewater, the rule imposed limits for arsenic, mercury, selenium, and nitrate/nitrite which will require the addition of biological treatment at Big Bend Station. Both fly ash and bottom ash transport water have been designated as zero discharge wastewaters, with the exception of use as make-up water in FGD scrubber. Transport water used as make-up will be subject to FGD wastewater limits at the point of discharge. New limits for gasification processes will likely require additional treatment at Polk Power Station. Cost estimates are being developed based on an evaluation of treatment technologies required to meet the pollutant limits. The new guidelines are expected to be incorporated into NPDES permit renewals to achieve compliance as soon as possible after Nov. 1, 2018, but no later than Dec. 31, 2023.

**EPA Waters of the US**

In June 2015, the U.S. Army Corps of Engineers (Corps) and the EPA issued a rule defining "Waters of the United States" (WOTUS) for purposes of federal Clean Water Act (CWA) jurisdiction. The final rule took effect on Aug. 28, 2015. The rule has the effect of defining the scope of agency jurisdiction under the CWA very broadly. In August 2015, a federal judge in North Dakota issued an injunction against the implementation of the rule in certain states. In October 2015, the Sixth Circuit Court of Appeals issued a nationwide stay of WOTUS, effectively ending the implementation of the rule in the 37 states that were not subject to the prior injunction. This stay is temporary, pending determination of the court's jurisdiction.

**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, 2015, TEC has estimated its ultimate financial liability to be $33.9 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**

Tampa Electric produces ash and other by-products, collectively known as CCRs, at its Big Bend and Polk power stations. 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, an annual average of 95% of all CCRs produced at these facilities is marketed to customers for beneficial use in commercial and industrial products. The remaining 5% are either disposed of onsite or shipped offsite to nearby industrial waste landfills in Central Florida.

EPA's final CCR rule became effective on Oct. 19, 2015, and regulates CCRs as non-hazardous solid waste. The rule explicitly allows for encapsulated beneficial uses of CCRs in commercial and industrial products. However, non-encapsulated uses in agricultural and construction applications are allowable only if they meet new environmental criteria.

The rule contains design and operating standards for CCR management units. Tampa Electric is currently evaluating various options for demonstrating compliance with the rule. Potential capital expenditures that are required to achieve compliance with this rule are not expected to be significant. On Feb. 2, 2016, the FPSC approved Tampa Electric's proposed CCR compliance program for cost recovery through the ECRC. The CCR rule has been challenged both by utility and environmental groups. Legislation has also been proposed in Congress to amend certain provisions of the CCR rule. Pending the outcome of the litigation and/or legislative amendment, the ultimate impacts of the CCR rule on Tampa Electric are uncertain at this time; however, it could curtail Tampa Electric's ability to market CCRs for beneficial reuse (see the **Risk Factors** section).

**Distributed Generation**

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. To date, there has not been a significant amount of distributed generation added to utility systems in Florida. Florida does not have a renewable portfolio standard, and Florida legislation and regulation have minimized social programs and costs in utility rates. However, proposed action by the Florida legislature in 2016 and a potential amendment to the Florida constitution that supporters are seeking to have placed on the ballot in 2018 would encourage the installation of solar arrays to generate electricity by retail customers and third parties, and allow limited sales of electricity by non-utility generators.

Additionally, the EPA's Clean Power Plan rule, if enacted as proposed, could have the effect of providing greater incentives for distributed generation in order to meet state-based emission reduction targets (see the **Carbon Reductions and GHG** discussion above, and **Item 1A - Risk Factors)**. Depending on how the rule is finally adopted, it could have the effect of increasing our costs or the rates charged to our customers, which could curtail sales.

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. Due to the intermittent availability of renewable resources, utilities must invest in adequate generating resources to meet customer demand at the times that renewable resources are not available. Energy storage technologies, such as batteries, are not yet commercially available to fill this demand. Continued utility investment not supported by increased future energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

**Conservation**

Energy conservation is becoming more important in the GHG emissions reduction debate. Tampa Electric supports the FPSC and its efforts to encourage energy efficiency. In 2015, Tampa Electric continued to offer its customers a comprehensive array of residential and commercial programs that enabled the company to meet its required Demand Side Management (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 348 MW and the winter peak demand by 740 MW.

In November 2014, the FPSC established new DSM goals for the 10-year period from 2015 to 2024 for all Florida investor-owned electric utilities. In November 2015, Tampa Electric transitioned into the new 2015-2024 DSM Plan by discontinuing nine existing DSM programs; creating one new DSM program; modifying twenty-eight existing DSM programs and retiring the renewable energy systems initiative. This transition supports the approved FPSC goals which are reasonable, beneficial and cost-effective to all customers as required by the Florida Energy Efficiency & Conservation Act (FEECA). For Tampa Electric, the summer and winter demand goals are 56.9 and 87.4 MWs, respectively, and the energy goal is 144.3 gigawatt-hours over the 10 year period. Establishing these DSM goals for the 10 year period is required every five years. 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 conservation programs that enable customers to reduce their energy consumption, with those costs recovered through a clause on the customer's gas 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. NMGC is subject to regulation by the NMPRC. The NMPRC has jurisdiction over the regulatory matters related, directly and indirectly, to NMGC providing service to its customers, including, among other things, rates, accounting procedures, securities issuances, and standards of service.

In general, for retail services, the FPSC and NMPRC's objective is to provide reliable service at fair and reasonable rates. The 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 the electric and gas utilities, 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). In Florida, 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. In New Mexico, 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 long-term debt and an allowed ROE. Base rates are determined in FPSC or NMPRC revenue requirement and rate setting hearings which occur at irregular intervals at the initiative of the utilities, FPSC, NMPRC 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 cumulative)
3. Nov. 1, 2015: Additional $5 million increase ($70 million cumulative)
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 the ROE becomes 10.50% if at any time during the agreement the six month average 30-year U.S. 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% ROE.

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 the 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 implemented a new Commercial and Industrial Service Rider (CISR) and an Economic Development Rate. The new Economic Development Rate was 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.

**Tampa Electric Cost-Recovery Clauses**

In November 2015, the FPSC approved Tampa Electric's rates for the various cost-recovery clauses for 2016. Tampa Electric's fuel filing reflected continued low natural gas prices as well as good unit performance and an over recovery of 2015 fuel costs, and reductions in the conservation and capacity clauses, which resulted in Tampa Electric seeking a total $2.70 reduction for 2016 for a residential customer using 1,000 kWh per month. As of Jan. 1, 2016, the total bill for a residential customer using 1,000 kWh was $106.22, compared to the December 2015 bill of $108.92.

**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 or solar 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.

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 or solar installation of 75 MW or more. 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.

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. 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 currently not permitted to make direct sales of electricity to end use customers. The allowance of direct third party sales would require action by the Florida legislature, which is not expected to be taken up in its 2016 session, or a constitutional amendment. See the **Solar Initiative** section of the **Tampa Electric Results from Operation** section.

**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.

**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 2015, the FPSC approved PGS' request for its PGA cap factor of $0.96046 per therm effective for 2016.

In addition to base rates and PGA clause charges, PGS customers (except interruptible customers) also pay a per-therm conservation charge. 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.

**PGS Compliance Activities**

In 2013, the FPSC audit staff cited PGS for not fully complying with FPSC rules mostly focused on record keeping for maintenance and record keeping in two of its divisions. PGS took immediate and significant corrective actions, including organizational, operational and system changes over the course of multiple years.

In 2015, the FPSC staff met with PGS officials to discuss perceived continuing issues associated with the PGS pipeline safety program. PGS was presented with a summary of safety rule violations, many of which were identified during PGS' implementation of its action plan as a result of the 2013 audit findings. Through ongoing discussions with the audit staff, PGS was made aware of concerns regarding falsification of documentation in one division. PGS determined that leak-inspection reports in 2014 were falsified. PGS took immediate actions to correct the findings, including reinspecting all pipes due for inspection in that division in 2014 and repaired deficiencies as appropriate.

The FPSC audit staff published a follow-up audit report that acknowledged the progress that had been made and found that further improvements were needed. As a result of this report, the Office of Public Counsel (OPC) filed a petition with the FPSC pointing to the violations of rules for safety inspections seeking fines or possible refunds to customers by PGS. On Feb. 25, 2016, the FPSC staff issued a notice informing PGS that the staff would be making a recommendation to the FPSC to initiate a show cause proceeding against PGS for the alleged violations, with total potential penalties of up to $3.9 million. PGS is continuing to work with the OPC and FPSC staff to resolve the issues.

**Utility Competition – Gas, Florida**

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 23,300 transportation-only customers as of Dec. 31, 2015, out of approximately 37,600 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.

**NMPRC**

Unlike the FPSC, which is appointed by the Governor of Florida and approved by the Florida Senate, the NMPRC is made up of five elected commissioners, each representing a specific geographic region of the state. NMPRC commissioners are elected to four-year terms. Commissioners are required to have at least 10 years of professional experience in areas regulated by the NMPRC or in the energy sector and involving accounting, public or business administration, economics, finance, statistics, engineering or law. The 10-year experience requirement can include the time spent earning the professional license or degree from an accredited institute of higher learning in the areas described above. In addition, ethic certification and continuing education requirements are mandated by New Mexico law.

Historically the NMPRC had used historical test periods in determining new rates; however legislation was enacted in 2009 that allows the NMPRC to utilize forecasted test periods. The first fully litigated case utilizing a forecasted test period was decided in 2014. In 2015, after considerable legal activity related to forecasted test periods by several utilities in New Mexico, the NMPRC issued an order clarifying the definition of what constitutes a future test year. The definition under that order states: "future test year" means that a rate case application filed by a public utility using a future test year may, but is not required to, use a fully forecasted test year that may begin as long as, but not later than, 13 months after the filing of the utility's application and advice notice. NMGC expects to utilize a forecasted test period in its next rate case.

**NMGC Rates**

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC's base rates by approximately $34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on Jan. 31, 2012, revising, among other things, base rates for all service provided on or after Feb. 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC's base rate revenue by approximately $21.5 million on a normalized annual basis. The monthly residential customer access fee increased from $9.59 to $11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017. In addition, under the order, NMGC provided $2.0 million of pretax credits on customer bills for the first 12-month period post-closing, effective Oct. 1, 2014, and will provide $4.0 million of pretax credits to customers in each subsequent 12-month period until new base rates are effective. See **Note 21** to the **TECO Energy Consolidated Financial Statements**.

**NMGC Cost-Recovery Clauses**

Like PGS, NMGC recovers the costs it pays for virtually all of its gas supply, storage and interstate transportation for system supply through the PGAC. Under this mechanism, customers that receive commodity gas from NMGC are charged a rate that allows NMGC to recover its actual cost of gas sold to those customers on a near real-time basis at no profit. This charge is adjusted on a monthly basis, based on the expected cost of gas and any prior month under-recovery or over-recovery of the cost of gas. NMGC may also include a simple interest charge or credit depending on any under-recovery or over-recovery of the cost of gas.

NMGC's annual PGAC period runs from Sept. 1 to Aug. 31. The NMPRC requires that NMGC file a reconciliation of the PGAC period costs and recoveries, in December of each year. NMGC must file a PGAC Continuation Filing with the NMPRC every four years. The most recent PGAC Continuation Filing was submitted to the NMPRC in June 2012. The purpose of the PGAC Continuation Filing is to establish that the continued use of the PGAC is reasonable and necessary. In January 2013, the NMPRC approved NMGC's June 2012 PGAC Continuation Filing, which allows for the continued use of the PGAC for another four years.

NMGC's cost of gas sold is charged to customers with no mark-up and, therefore, NMGC does not earn any profit on the gas commodity reflected on customer bills. Despite the fact that NMGC does not earn any profit on the commodity gas, this cost may generate significant increases or decreases in NMGC's revenues, due to changes in the market price of natural gas, and corresponding increases or decreases in the cost of natural gas sold, a component of NMGC's operating expenses.

In addition to base rates and PGAC clause charges, NMGC's residential customers and customers utilizing NMGC's small and medium volume general services also pay a per-therm charge for energy conservation. This charge is intended to permit NMGC to recover costs incurred in developing and implementing energy conservation programs, which are mandated by New Mexico law and approved and supervised by the NMPRC every two years. NMGC 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 customers.

**Utility Competition – Gas, New Mexico**

Although NMGC 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. NMGC has taken actions to retain and expand its natural gas distribution business, including managing costs and providing high quality service to customers.

NMGC is required to provide transportation-only services for all customer classes. As a result, NMGC receives its base rates for distribution gas delivery services regardless of whether a customer elects transportation-only service or continues as a customer of NMGC's gas commodity sales service. As of Dec. 31, 2015, NMGC had approximately 4,100 transportation-only customers and approximately 512,000 gas commodity sales service end-use customers.

## 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 our electric and gas utilities; and
- Interest rate fluctuations on debt of TECO Energy and its affiliates.

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.

### Fair Value Measurements

The accounting standards for fair value measurement define fair value, establish a framework for measuring fair value under U.S. 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 or interest rate derivatives classified as cash flow hedges.

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, PGS and NMGC 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 recovery clause, the unrealized gains and losses associated with the valuation of these assets and liabilities do not impact our results of operations.

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 Risk Guidelines, which are approved by the RAC, 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 are made available to management on a daily basis. The Credit Risk 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, including forward-looking data such as 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 liability positions on Dec. 31, 2015. If the credit-risk related contingent features underlying these agreements were triggered as of Dec. 31, 2015, we could have been required to post collateral or settle existing positions with counterparties totaling $26.2 million. In the unlikely event that this situation would occur, we believe that we maintain adequate lines of credit to meet those obligations.

**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, 2015 and 2014, 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 3.1% at Dec. 31, 2015 and 2.8% at Dec. 31, 2014 (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**

Tampa Electric's fuel costs used for generation were affected primarily by the price of natural gas and, to a lesser degree, the cost of coal and fuel oil. Tampa Electric's use of natural gas, with its more volatile pricing, for generation of electricity increased to more than 50% in 2015 (see the **Business** section). PGS and NMGC have exposure related to the price of purchased gas and pipeline capacity.

Currently, our electric and gas utilities' commodity price risks are largely mitigated by the fact that increases in the price of fuel and purchased power are recovered through FPSC or NMPRC-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, our electric and gas utilities 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, 2015 and 2014, a change in commodity prices would not have had a material impact on earnings for Tampa Electric, PGS or NMGC, 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 above).

**Changes in Fair Value of Derivatives**

The change in fair value of derivatives is largely due to settlements of natural gas swaps and the decrease in the average market price component of the company's outstanding natural gas swaps of approximately 27% from Dec. 31, 2014 to Dec. 31, 2015. For natural gas, the company maintained a similar volume hedged as of Dec. 31, 2015 as compared to Dec. 31, 2014.

The following tables summarize the changes in and the fair value balances of derivative assets (liabilities) for the year ended Dec. 31, 2015:

**Changes in Fair Value of Derivatives (millions)**

| | | |
|---|---|---|
| Net fair value of derivatives as of Dec. 31, 2014 | $ | (42.7) |
| Additions and net changes in unrealized fair value of derivatives | | (28.5) |
| Changes in valuation techniques and assumptions | | 0.0 |
| Realized net settlement of derivatives | | 45.2 |
| Net fair value of derivatives as of Dec. 31, 2015 | $ | (26.0) |

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

| | | |
|---|---|---|
| Total derivative net liabilities as of Dec. 31, 2014 | $ | (42.7) |
| Change in fair value of net derivative assets: | | |
| Recorded as regulatory assets and liabilities or other comprehensive income | | (29.5) |
| Recorded in earnings | | 0.0 |
| Realized net settlement of derivatives | | 45.2 |
| Net option premium payments | | 1.0 |
| Net fair value of derivatives as of Dec. 31, 2015 | $ | (26.0) |

**Maturity and Source of Energy Derivative Contracts Net Assets (Liabilities) at Dec. 31, 2015**

| *(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)] | (23.9) | (2.1) | (26.0) |
| Model prices [(2)] | 0.0 | 0.0 | 0.0 |
| Total | $ (23.9) | $ (2.1) | $ (26.0) |

(1) Reflects over-the-counter natural gas 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.

**Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.**

## TECO ENERGY, INC.

### 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 index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of TECO Energy, Inc. and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in the 2013 *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.

As discussed in Note 2 to the financial statements, the Company changed the manner in which it classifies deferred taxes in 2015.

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 26, 2016

## TECO ENERGY, INC.
## Consolidated Balance Sheets

| **Assets** *(millions)* | *Dec. 31, 2015* | *Dec. 31, 2014* |
|---|---|---|
| **Current assets** | | |
| Cash and cash equivalents | $ 23.8 | $ 25.4 |
| Receivables, less allowance for uncollectibles of $2.1 and $2.1 at Dec. 31, 2015 and 2014, respectively | 280.7 | 299.8 |
| Inventories, at average cost | | |
| Fuel | 113.4 | 96.4 |
| Materials and supplies | 76.8 | 75.4 |
| Regulatory assets | 44.8 | 53.6 |
| Deferred income taxes | 0.0 | 72.8 |
| Prepayments and other current assets | 30.8 | 22.6 |
| Assets held for sale | 0.0 | 109.6 |
| Total current assets | 570.3 | 755.6 |
| **Property, plant and equipment** | | |
| Utility plant in service | | |
| Electric | 7,270.3 | 7,094.8 |
| Gas | 2,113.8 | 1,984.6 |
| Construction work in progress | 794.7 | 640.0 |
| Other property | 15.9 | 14.5 |
| Property, plant and equipment, at original costs | 10,194.7 | 9,733.9 |
| Accumulated depreciation | (2,712.9) | (2,645.7) |
| Total property, plant and equipment, net | 7,481.8 | 7,088.2 |
| **Other assets** | | |
| Regulatory assets | 395.2 | 348.5 |
| Goodwill | 408.4 | 408.3 |
| Deferred charges and other assets | 105.4 | 65.8 |
| Assets held for sale | 0.0 | 59.8 |
| Total other assets | 909.0 | 882.4 |
| **Total assets** | $ 8,961.1 | $ 8,726.2 |

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, 2015* | *Dec. 31, 2014* |
|---|---|---|
| **Current liabilities** | | |
| Long-term debt due within one year | $ 333.3 | $ 274.5 |
| Notes payable | 247.0 | 139.0 |
| Accounts payable | 255.4 | 288.6 |
| Customer deposits | 182.1 | 176.2 |
| Regulatory liabilities | 84.8 | 57.0 |
| Derivative liabilities | 24.1 | 36.6 |
| Interest accrued | 36.2 | 39.9 |
| Taxes accrued | 13.2 | 29.9 |
| Other | 22.6 | 16.8 |
| Liabilities associated with assets held for sale | 0.0 | 39.4 |
| Total current liabilities | 1,198.7 | 1,097.9 |
| **Other liabilities** | | |
| Deferred income taxes | 570.7 | 519.2 |
| Investment tax credits | 10.5 | 9.0 |
| Regulatory liabilities | 715.8 | 729.0 |
| Derivative liabilities | 2.1 | 6.1 |
| Deferred credits and other liabilities | 387.4 | 370.9 |
| Liabilities associated with assets held for sale | 0.0 | 65.4 |
| Long-term debt, less amount due within one year | 3,516.9 | 3,354.0 |
| Total other liabilities | 5,203.4 | 5,053.6 |
| **Commitments and Contingencies (see Note 12)** | | |
| **Capital** | | |
| Common equity (400.0 million shares authorized; par value $1; 235.3 million and 234.9 million shares outstanding at Dec. 31, 2015 and 2014, respectively) | 235.3 | 234.9 |
| Additional paid in capital | 1,894.5 | 1,875.9 |
| Retained earnings | 441.4 | 479.6 |
| Accumulated other comprehensive loss | (12.2) | (15.7) |
| Total TECO Energy capital | 2,559.0 | 2,574.7 |
| **Total liabilities and capital** | $ 8,961.1 | $ 8,726.2 |

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,* | | *2015* | *2014* | *2013* |
|---|---|---|---|---|
| **Revenues** | | | | |
| Regulated electric | | $ 2,014.9 | $ 2,019.9 | $ 1,949.6 |
| Regulated gas | | 716.8 | 537.4 | 392.9 |
| Unregulated | | 11.8 | 9.1 | 12.6 |
| Total revenues | | 2,743.5 | 2,566.4 | 2,355.1 |
| **Expenses** | | | | |
| Regulated operations and maintenance | | | | |
| Fuel | | 638.6 | 692.3 | 680.2 |
| Purchased power | | 78.9 | 71.4 | 64.7 |
| Cost of natural gas sold | | 271.6 | 209.7 | 142.2 |
| Other | | 613.2 | 547.8 | 524.4 |
| Operation and maintenance other expense | | 22.7 | 29.5 | 12.5 |
| Depreciation and amortization | | 349.0 | 315.3 | 291.8 |
| Taxes, other than income | | 207.4 | 195.0 | 184.7 |
| Total expenses | | 2,181.4 | 2,061.0 | 1,900.5 |
| **Income from operations** | | 562.1 | 505.4 | 454.6 |
| **Other income (expense)** | | | | |
| Allowance for other funds used during construction | | 17.4 | 10.5 | 6.3 |
| Other income | | 3.4 | 0.5 | 1.8 |
| Total other income | | 20.8 | 11.0 | 8.1 |
| **Interest charges** | | | | |
| Interest expense | | 195.1 | 176.4 | 165.0 |
| Allowance for borrowed funds used during construction | | (8.7) | (5.3) | (3.6) |
| Total interest charges | | 186.4 | 171.1 | 161.4 |
| **Income from continuing operations before provision for income taxes** | | 396.5 | 345.3 | 301.3 |
| Provision for income taxes | | 155.3 | 138.9 | 112.6 |
| **Net income from continuing operations** | | 241.2 | 206.4 | 188.7 |
| **Discontinued operations** | | | | |
| Income (loss) from discontinued operations | | (106.3) | (125.4) | 5.2 |
| Provision (benefit) for income taxes | | (38.6) | (49.4) | (3.8) |
| Income (loss) from discontinued operations, net | | (67.7) | (76.0) | 9.0 |
| **Net income** | | $ 173.5 | $ 130.4 | $ 197.7 |
| **Average common shares outstanding** | – Basic | 233.1 | 223.1 | 215.0 |
| | – Diluted | 234.5 | 223.7 | 215.5 |
| **Earnings per share from continuing operations** | – Basic | $ 1.03 | $ 0.92 | $ 0.88 |
| | – Diluted | $ 1.03 | $ 0.92 | $ 0.88 |
| **Earnings per share from discontinued operations** | – Basic | $ (0.29) | $ (0.34) | $ 0.04 |
| | – Diluted | $ (0.29) | $ (0.34) | $ 0.04 |
| **Earnings per share** | – Basic | $ 0.74 | $ 0.58 | $ 0.92 |
| | – Diluted | $ 0.74 | $ 0.58 | $ 0.92 |
| Dividends paid per common share outstanding | | $ 0.90 | $ 0.88 | $ 0.88 |

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,* | *2015* | *2014* | *2013* |
|---|---|---|---|
| **Net income** | $ 173.5 | $ 130.4 | $ 197.7 |
| **Other comprehensive income (loss), net of tax** | | | |
| Gain on cash flow hedges | 3.5 | 0.7 | 1.4 |
| Amortization of unrecognized benefit costs and other | 2.1 | (3.0) | 14.8 |
| Change in benefit obligation due to valuation | (9.8) | 8.0 | 0.0 |
| Increase in unrecognized postemployment costs | 0.0 | (8.2) | 0.0 |
| Recognized benefit costs due to settlement | 7.7 | 0.0 | 1.6 |
| Other comprehensive income (loss), net of tax | 3.5 | (2.5) | 17.8 |
| **Comprehensive income** | $ 177.0 | $ 127.9 | $ 215.5 |

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,* | *2015* | *2014* | *2013* |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Net income | $ 173.5 | $ 130.4 | $ 197.7 |
| Adjustments to reconcile net income to net cash from operating activities: | | | |
| Depreciation and amortization | 350.2 | 341.9 | 329.5 |
| Deferred income taxes and investment tax credits | 117.5 | 89.4 | 110.1 |
| Allowance for other funds used during construction | (17.4) | (10.5) | (6.3) |
| Non-cash stock compensation | 13.1 | 12.7 | 13.5 |
| Loss (gain) on disposals of business/assets | 13.2 | (0.2) | (1.6) |
| Deferred recovery clauses | 26.4 | (15.2) | (6.2) |
| Asset impairment | 78.6 | 115.9 | 0.0 |
| Receivables, less allowance for uncollectibles | 36.0 | (36.6) | (4.5) |
| Inventories | (22.6) | 12.8 | 1.1 |
| Prepayments and other current assets | (8.0) | 2.8 | (2.2) |
| Taxes accrued | (15.9) | 1.1 | 1.4 |
| Interest accrued | (3.6) | 7.3 | (1.3) |
| Accounts payable | (61.6) | 23.4 | 35.9 |
| Other | (69.8) | (10.4) | (8.5) |
| Cash flows from operating activities | 609.6 | 664.8 | 658.6 |
| **Cash flows from investing activities** | | | |
| Capital expenditures | (739.7) | (703.8) | (526.1) |
| Purchase of NMGI, net of cash acquired | 0.0 | (751.5) | 0.0 |
| Net proceeds from sales of business/assets | 0.0 | 0.2 | 4.3 |
| Other investments | (0.3) | (7.9) | 0.0 |
| Cash flows used in investing activities | (740.0) | (1,463.0) | (521.8) |
| **Cash flows from financing activities** | | | |
| Dividends paid | (211.7) | (199.2) | (191.2) |
| Proceeds from the sale of common stock | 7.3 | 302.3 | 6.7 |
| Proceeds from long-term debt issuance | 499.7 | 563.6 | 0.0 |
| Repayment of long-term debt/Purchase in lieu of redemption | (274.5) | (83.3) | (51.6) |
| Change in short-term debt | 108.0 | 55.0 | 84.0 |
| Cash flows from/(used in) financing activities | 128.8 | 638.4 | (152.1) |
| Net decrease in cash and cash equivalents | (1.6) | (159.8) | (15.3) |
| Cash and cash equivalents at beginning of the year | 25.4 | 185.2 | 200.5 |
| Cash and cash equivalents at end of the year | $ 23.8 | $ 25.4 | $ 185.2 |
| **Supplemental disclosure of cash flow information** | | | |
| Cash paid during the year for: | | | |
| Interest | $ 179.6 | $ 161.3 | $ 161.0 |
| Income taxes paid | $ 14.5 | $ 2.9 | $ 1.8 |
| **Supplemental disclosure of non-cash activities** | | | |
| Debt assumed in NMGI acquisition | $ 0.0 | $ 200.0 | $ 0.0 |
| Change in accrued capital expenditures | $ 8.0 | $ 13.3 | $ 4.7 |

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

## TECO ENERGY, INC.
## Consolidated Statements of Capital

| *(millions)* | Shares | Common Stock | Additional Paid in Capital | Retained Earnings | Accumulated Other Comprehensive Income (Loss) | Total Capital |
|---|---|---|---|---|---|---|
| Balance, Dec. 31, 2012 | 216.6 | $ 216.6 | $ 1,564.5 | $ 541.7 | $ (31.0) | $ 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) | $ 2,333.7 |
| Net income | | | | 130.4 | | 130.4 |
| Other comprehensive income, after tax | | | | | (2.5) | (2.5) |
| Common stock issued | 17.6 | 17.6 | 283.2 | | | 300.8 |
| Cash dividends declared | | | | (199.2) | | (199.2) |
| Stock compensation expense | | | 12.7 | | | 12.7 |
| Restricted stock—dividends | | | 1.1 | 0.1 | | 1.2 |
| Tax short fall—stock compensation | | | (2.4) | | | (2.4) |
| Balance, Dec. 31, 2014 | 234.9 | $ 234.9 | $ 1,875.9 | $ 479.6 | $ (15.7) | $ 2,574.7 |
| Net income | | | | 173.5 | | 173.5 |
| Other comprehensive loss, after tax | | | | | 3.5 | 3.5 |
| Common stock issued | 0.4 | 0.4 | 4.6 | | | 5.0 |
| Cash dividends declared | | | | (211.7) | | (211.7) |
| Stock compensation expense | | | 13.1 | | | 13.1 |
| Restricted stock—dividends | | | 1.3 | | | 1.3 |
| Tax short fall—stock compensation | | | (0.4) | | | (0.4) |
| Balance, Dec. 31, 2015 | 235.3 | $ 235.3 | $ 1,894.5 | $ 441.4 | $ (12.2) | $ 2,559.0 |

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

**TECO ENERGY, INC.**
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

## 1. Significant Accounting Policies

### Description of the Business

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, NMGI, owns NMGC.

TEC, a Florida corporation and TECO Energy's largest subsidiary, has two business segments. Its Tampa Electric division provides retail electric services in West Central Florida, and 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.

NMGC, a Delaware corporation and wholly owned subsidiary of NMGI, was acquired by the company on Sept. 2, 2014. NMGC is engaged in the purchase, distribution and sale of natural gas for residential, commercial and industrial customers in New Mexico.

On Sept. 21, 2015, TECO Diversified sold all of its ownership interest in TECO Coal. TECO Coal, a Kentucky LLC, had subsidiaries which owned assets in Eastern Kentucky, Tennessee and Virginia. These entities owned mineral rights, owned or operated surface and underground mines and owned interests in coal processing and loading facilities. See **Note 19** for further information.

On Sept. 4, 2015, TECO Energy and Emera entered into the Merger Agreement. Upon closing, TECO Energy will become a wholly owned indirect subsidiary of Emera. See **Note 21** for further information.

The company's significant accounting policies are as follows:

### Principles of Consolidation and Basis of Presentation

The consolidated financial statements include the accounts of TECO Energy and its majority-owned subsidiaries. Intercompany balances and intercompany transactions have been eliminated in consolidation.

The consolidated financial statements include NMGI and NMGC from the acquisition date of Sept. 2, 2014 through Dec. 31, 2015 (see **Note 21**). In addition, all periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for TECO Coal and certain charges at Parent and TECO Diversified that directly related to TECO Coal and TECO Guatemala (see **Note 19**).

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 noncontrolling 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**).

Through its centralized services company subsidiary, TSI, TECO Energy provides its operating subsidiaries with specialized services at cost, including information technology, procurement, human resources, legal, risk management, financial, and administrative services. TSI's costs are directly charged or allocated to the applicable operating subsidiaries using cost-causative allocation methods. Corporate governance-type costs that cannot be directly assigned are allocated based on a Modified Massachusetts Formula, which is a method that utilizes a combination of total operating revenues, total operating assets and net income as the basis of allocation. TSI has losses related to taxes which are not distributed to affiliate companies. The results of TECO Energy's corporate operations, consisting of TSI tax losses and non-allocable Parent costs, are included within the "Other" reportable segment (see **Note 14**).

### Use of Estimates

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

### 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.

**Property, Plant and Equipment**

Property, plant and equipment is stated at original cost, which includes labor, material, applicable taxes, overhead and AFUDC. Tampa Electric, PGS and NMGC, concurrent with a planned major maintenance outage or with new construction, capitalize the cost of adding or replacing retirement units-of-property in conformity with the regulations of FERC, FPSC and NMPRC, as applicable. The cost of maintenance, repairs and replacement of minor items of property is expensed as incurred.

In general, when regulated depreciable property is retired or disposed, its original cost less salvage is charged to accumulated depreciation. For other property dispositions, the cost and accumulated depreciation are removed from the balance sheet and a gain or loss is recognized.

**Depreciation**

Tampa Electric, PGS and NMGC 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 or NMPRC, 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 or NMPRC, 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 2015, 3.6% for 2014 and 3.7% for 2013. Construction work in progress is not depreciated until the asset is completed or placed in service.

On Sept. 11, 2013, the FPSC unanimously voted to approve a stipulation and settlement agreement between Tampa Electric and all of the intervenors in its Tampa Electric division base rate proceeding. As a result, Tampa Electric began 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 | 40 years |
| Office equipment and furniture | 4 - 7 years |
| Computer software | 3 - 15 years |

Total depreciation expense for the years ended Dec. 31, 2015, 2014 and 2013 was $339.1 million, $307.5 million and $285.6 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 Tampa Electric's AFUDC is revised periodically to reflect significant changes in Tampa Electric's cost of capital. Tampa Electric's rate was 8.16% for May 2009 through December 2013. In March 2014, the rate was revised to 6.46% effective Jan. 1, 2014. NMGC's rate used to calculate its AFUDC in 2015 and 2014 was 4.41% and 4.92%, respectively. Total AFUDC for the years ended Dec. 31, 2015, 2014 and 2013 was $26.1 million, $15.8 million and $9.9 million, respectively.

**Inventory**

TEC and NMGC value materials, supplies and fossil fuel inventory (coal, oil or 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.

| **Fuel Inventory** *(millions)* | *Dec. 31, 2015* | *Dec. 31, 2014* |
|---|---|---|
| TEC | $ 105.6 | $ 85.2 |
| NMGC | 7.8 | 11.2 |
| Total | $ 113.4 | $ 96.4 |

TECO Coal inventories were stated at the lower of cost, computed on the first-in, first-out method, or net realizable value. Parts and supplies inventories were stated at the lower of cost or market on an average cost basis. TECO Coal's inventory was classified within Assets held for sale at Dec. 31, 2014.

**Regulatory Assets and Liabilities**

Tampa Electric, PGS and NMGC 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.

**Goodwill**

Goodwill is calculated as the excess of the purchase price of an acquired entity over the estimated fair values of assets acquired and liabilities assumed at the acquisition date. Under the accounting guidance for goodwill, goodwill is subject to an annual assessment for impairment at the reporting unit level. See **Note 20** for further detail.

**Employee Postretirement Benefits**

The company sponsors a defined benefit retirement plan and other postretirement benefits. The measurement of the plans are based on several statistical and other factors, including those that attempt to anticipate future events. See **Note 5** for further detail.

**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' retail businesses and the prices charged to customers are regulated by the FPSC or NMPRC, as applicable. 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 energy marketing operations at TECO EnergySource, Inc. 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. Accordingly, for the years ended Dec. 31, 2015, 2014 and 2013, total costs of $3.1 million, $4.3 million and $23.1 million, respectively, consisting primarily of natural gas purchased, were netted against revenues in the "Revenues-Unregulated" caption on the Consolidated Statements of Income.

Revenues for TECO Coal shipments, both domestic and international, were recognized when title and risk of loss transfer to the customer. They were included in "Income (loss) from discontinued operations" on the Consolidated Statements of Income.

**Revenues and Cost Recovery**

Revenues include amounts resulting from cost recovery clauses at the regulated utilities (Tampa Electric, PGS and NMGC) 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, gas storage, interstate pipeline capacity and conservation costs for PGS and NMGC. 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 for a closer matching of revenues and expenses (see **Note 3**). As of Dec. 31, 2015 and 2014, unbilled revenues of $81.1 million and $86.6 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 $78.9 million, $71.4 million and $64.7 million, for the years ended Dec. 31, 2015, 2014 and 2013, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost recovery clause.

**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 the regulated utilities' collection experience. Circumstances that could affect Tampa Electric's, PGS's and NMGC'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, which were classified within Assets held for sale at Dec. 31, 2014, consisted of coal sales billed to industrial and utility customers. An allowance for uncollectible accounts was established based on TECO Coal's collection experience. Circumstances that could have affected TECO Coal's estimates of uncollectible receivables included customer credit issues and general economic conditions. Accounts were written off once they were determined to be uncollectible.

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

Tampa Electric and PGS are allowed to recover certain costs on a dollar-for-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 Tampa Electric and PGS are included as an expense on the Consolidated Statements of Income in "Taxes, other than income". These amounts totaled $116.9 million, $113.9 million and $108.5 million for the years ended Dec. 31, 2015, 2014 and 2013, respectively. NMGC is an agent in the collection and payment of franchise fees and gross receipt taxes and is not required by a tariff to present the amounts on a gross basis. Therefore, NMGC's franchise fees and gross receipt taxes are presented net with no line item impact on the Consolidated Statement of Income.

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

**Deferred Charges and Other Assets**

Deferred charges and other assets consist primarily of a contribution made by the company in order to fully fund its SERP obligation (see **Note 5**), unamortized debt issuance costs and assets related to NMGC's ROW.

*Debt issuance costs* – The company capitalizes the external costs of obtaining debt financing 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.

*NMGC's ROW*- Gross assets related to NMGC's ROW were $41 million at Dec. 31, 2015 and 2014. The related accumulated amortization was $9 million and $8 million at Dec. 31, 2015 and 2014, respectively. The company amortizes costs related to obtaining NMGC's ROW to "Depreciation and amortization expense" on TECO Energy's Consolidated Statements of Income.

**Deferred Credits and Other Liabilities**

Deferred credits and other liabilities primarily include the accrued postretirement and pension liabilities (see **Note 5**), MGP environmental remediation liability (see **Note 12**), 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, 2015 and 2014 ranged from 2.92% to 4.00% and 2.71% 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, stock-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.

**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.

**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**

**Revenue from Contracts with Customers**

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The standard is principle-based and provides a five-step model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In addition, the guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. This guidance will be effective for the company beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. The company expects to adopt this guidance effective Jan. 1, 2018, and is continuing to evaluate the available adoption methods and the impact of the adoption of this guidance on its financial statements, but does not expect the impact to be significant.

**Presentation of Debt Issuance Costs**

In April 2015, the FASB issued guidance regarding the presentation of debt issuance costs on the balance sheet. Under the new guidance, an entity is required to present debt issuance costs as a direct deduction from the carrying amount of the related debt liability rather than as a deferred charge (i.e., as an asset) under current guidance. In August 2015, the FASB amended the guidance to include an SEC staff announcement that it will not object to a company presenting debt issuance costs related to line-of-credit arrangements as an asset, regardless of whether a balance is outstanding. This guidance will be effective for the company beginning in 2016 and will be required to be applied on a retrospective basis for all periods presented. As of Dec. 31, 2015, $27.7 million of debt issuance costs, which does not include costs for line-of-credit arrangements, are included in the "Deferred charges and other assets" line item on the company's Consolidated Condensed Balance Sheet. The guidance will not affect the company's results of operations or cash flows.

**Disclosure of Investments Using Net Asset Value**

In May 2015, the FASB issued guidance stating that investments for which fair value is measured using the NAV per share practical expedient should not be categorized in the fair value hierarchy but should be provided to reconcile to total investments on the balance sheet. In addition, the guidance clarifies that a plan sponsor's pension assets are eligible to be measured at NAV as a practical expedient and that those investments should also not be categorized in the fair value hierarchy. TECO Energy's pension plan has such investments as disclosed in **Note 5**. This standard will be required for the company beginning in 2016. As early adoption is permitted, the company adopted the standard for its 2015 fiscal year and applied the presentation on a retrospective basis for all periods presented in the pension plan assets fair value hierarchy. The guidance did not affect the company's balance sheets, results of operations or cash flows.

**Measurement Period Adjustments in Business Combinations**

In September 2015, the FASB issued guidance requiring an acquirer in a business combination to account for measurement period adjustments during the reporting period in which the adjustment is determined, rather than retrospectively. When measurements are incomplete as of the end of the reporting period covering a business combination, an acquirer may record adjustments to provisional amounts based on events and circumstances that existed as of the acquisition date during the period from the date of acquisition to the date information is received, not to exceed one year. The guidance will be effective for the company beginning in 2016 and will be applied prospectively. The guidance will not affect the company's current financial statements. However, the company will assess the potential impact of the guidance on future acquisitions.

**Balance Sheet Classification of Deferred Taxes**

In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. To simplify the presentation of deferred income taxes, the new guidance requires that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet rather than be classified as current or noncurrent under current guidance. The guidance will be required for the company beginning in 2017 and may be applied on a prospective or retrospective basis. As early adoption is permitted, the company adopted the standard in December 2015 and applied the balance sheet presentation on a prospective basis. Therefore, prior period balance sheets were not retrospectively adjusted. The guidance did not affect the company's results of operations or cash flows.

**Recognition and Measurement of Financial Assets and Financial Liabilities**

In January 2016, the FASB issued guidance related to accounting for financial instruments, including equity investments, financial liabilities under the fair value option, valuation allowances for available-for-sale debt securities, and the presentation and disclosure requirements for financial instruments. The company does not have equity investments or available-for-sale debt securities and it does not record financial liabilities under the fair value option. However, it is evaluating the impact of the adoption of this guidance on its financial statement disclosures, including those regarding the fair value of its long-term debt, but it does not expect the impact to be significant. The guidance will be effective for the company beginning in 2018.

**Leases**

In February 2016, the FASB issued guidance regarding the accounting for leases. The objective is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with a lease term of more than 12 months. In addition, the guidance will require additional disclosures regarding key information about leasing arrangements. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. The dual model for income statement classification is maintained under the new guidance and as a result is expected to limit the impact of the changes on the income statement and statement of cash flows. This guidance will be effective for the company beginning in 2019, with early adoption permitted, and will be applied using a modified retrospective approach. The company is currently evaluating the impacts of the adoption of the guidance on its financial statements.

**3. Regulatory**

Tampa Electric's retail business and PGS are regulated by the FPSC. Tampa Electric is also subject to regulation by the FERC. 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.

NMGC is subject to regulation by the NMPRC. The NMPRC has jurisdiction over the regulatory matters related, directly and indirectly, to NMGC providing service to its customers, including, among other things, rates, accounting procedures, securities issuances, and standards of service. NMGC must follow certain accounting guidance that pertains specifically to entities that are subject to such regulation. Comparable to the FPSC, the NMPRC sets rates at a level that allows utilities such as NMGC to collect total revenues (revenue requirement) 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 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.

Tampa Electric's results for 2015, 2014 and the last two months of 2013 reflect the results of a Stipulation and Settlement Agreement entered on Sept. 6, 2013, between Tampa Electric and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric's 2013 base rate proceeding. On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement.

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 Tampa Electric'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 no sooner than Jan. 1, 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 Tampa Electric could seek a review of its base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital and Tampa Electric began using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013.

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.

**Tampa Electric Storm Damage Cost Recovery**

Prior to the above-mentioned stipulation and settlement agreement, Tampa Electric was accruing $8.0 million annually to a 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. Effective Nov. 1, 2013, Tampa Electric ceased accruing for this storm damage reserve as a result of the 2013 rate case settlement. 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 $56.1 million; the level it was as of Oct. 31, 2013. Tampa Electric's storm reserve remained $56.1 million at both Dec. 31, 2015 and 2014.

**Base Rates-PGS**

PGS's base rates were established in May 2009 and reflect an ROE of 10.75%, which is the middle of a range between 9.75% to 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.

**Base Rates-NMGC**

In March 2011, NMGC filed an application with the NMPRC seeking authority to increase NMGC's base rates by approximately $34.5 million on a normalized annual basis. In September 2011, the parties to the base rate proceeding entered into a settlement. The parties filed an unopposed stipulation reflecting the terms of that settlement with the NMPRC and the unopposed stipulation was approved by the NMPRC on Jan. 31, 2012, revising, among other things, base rates for all service provided on or after Feb. 1, 2012. The revised rates contained in the NMPRC-approved settlement increased NMGC's base rate revenue by approximately $21.5 million on a normalized annual basis. The monthly residential customer access fee increased from $9.59 to $11.50, with the remaining rate increase reflected in changes to volumetric delivery charges. The parties stipulated that the NMPRC-approved revised rates would not increase again prior to July 31, 2013. Subsequently, as a condition of the August 2014 NMPRC order approving the TECO Energy acquisition of NMGC, the rates were frozen at the approved 2012 levels until the end of 2017, as reported in **Note 21.**

**Regulatory Assets and Liabilities**

Tampa Electric, PGS and NMGC 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; 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; and the advance recovery of expenditures for approved costs such as future storm damage or the future removal of property. All regulatory assets are recovered through the regulatory process.

Details of the regulatory assets and liabilities as of Dec. 31, 2015 and 2014 are presented in the following table:

| *(millions)* | *Dec. 31, 2015* | *Dec. 31, 2014* |
|---|---|---|
| **Regulatory assets:** | | |
| Regulatory tax asset [1] | $ 74.7 | $ 69.2 |
| Cost-recovery clauses - deferred balances [2] | 5.5 | 1.9 |
| Cost-recovery clauses - offsets to derivative liabilities [2] | 26.5 | 43.2 |
| Environmental remediation [3] | 54.0 | 53.1 |
| Postretirement benefits [4] | 240.6 | 194.0 |
| Deferred bond refinancing costs [5] | 6.5 | 7.2 |
| Debt basis adjustment [6] | 17.5 | 20.9 |
| Competitive rate adjustment [2] | 2.6 | 2.8 |
| Other | 12.1 | 9.8 |
| Total regulatory assets | 440.0 | 402.1 |
| Less: Current portion | 44.8 | 53.6 |
| Long-term regulatory assets | $ 395.2 | $ 348.5 |
| **Regulatory liabilities:** | | |
| Regulatory tax liability | $ 7.9 | $ 6.9 |
| Cost-recovery clauses [2] | 55.9 | 25.9 |
| Transmission and delivery storm reserve | 56.1 | 56.1 |
| Accumulated reserve—cost of removal [7] | 679.9 | 695.2 |
| Other | 0.8 | 1.9 |
| Total regulatory liabilities | 800.6 | 786.0 |
| Less: Current portion | 84.8 | 57.0 |
| Long-term regulatory liabilities | $ 715.8 | $ 729.0 |

(1) The regulatory tax asset is primarily associated with the depreciation and recovery of AFUDC-equity. This asset does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be recovered over the expected life of the related assets.

(2) These assets and liabilities are related to FPSC and NMPRC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in the next year. In the case of the regulatory asset related to derivative liabilities, recovery occurs in the year following the settlement of the derivative position.

(3) This asset is related to costs associated with environmental remediation primarily at manufactured gas plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is impacted by the timing of the expenditures related to remediation.

(4) This asset is related to the deferred costs of postretirement benefits. It is included in rate base and earns a rate of return as permitted by the FPSC or NMPRC, as applicable. It is amortized over the remaining service life of plan participants.

(5) This asset represents the past costs associated with refinancing debt. It does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be amortized over the term of the related debt instruments.

(6) This asset represents the difference between the fair value and pre-merger carrying amounts for NMGC's long-term debt on the acquisition date. It does not earn a return and is not included in the regulatory capital structure. It is amortized over the term of the related debt instrument.

(7) This item represents the non-ARO cost of removal in the accumulated reserve for depreciation.

## 4. Income Taxes

### Income Tax Expense

In 2015, 2014 and 2013, TECO Energy recorded net tax provisions from continuing operations of $155.3 million, $138.9 million and $112.6 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 and prior year audits in 2015, 2014 and 2013 were $14.5 million, $2.9 million and $1.8 million, respectively.

Income tax expense consists of the following:

**Income Tax Expense (Benefit)**

| *(millions)* *For the year ended Dec. 31,* | *2015* | *2014* | *2013* |
|---|---|---|---|
| **Continuing Operations** | | | |
| Current income taxes | | | |
| Federal | $ (0.5) | $ 0.5 | $ 2.2 |
| State | 0.0 | 0.0 | 0.0 |
| Deferred income taxes | | | |
| Federal | 133.2 | 111.0 | 98.8 |
| State | 21.1 | 27.7 | 11.9 |
| Amortization of investment tax credits | 1.5 | (0.3) | (0.3) |
| Income tax expense from continuing operations | 155.3 | 138.9 | 112.6 |
| **Discontinued Operations** | | | |
| Current income taxes | | | |
| Federal | 0.0 | 0.0 | 0.0 |
| State | (0.3) | (0.4) | (3.5) |
| Deferred income taxes | | | |
| Federal | (34.7) | (44.0) | (0.3) |
| State | (3.6) | (5.0) | 0.0 |
| Income tax expense from discontinued operations | (38.6) | (49.4) | (3.8) |
| Total income tax expense | $ 116.7 | $ 89.5 | $ 108.8 |

During 2015, 2014 and 2013, TECO Energy increased its net operating loss carryforward.

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,* | *2015* | *2014* | *2013* |
|---|---|---|---|
| Income tax expense at the federal statutory rate of 35% | $ 138.8 | $ 120.9 | $ 105.5 |
| Increase (decrease) due to: | | | |
| State income tax, net of federal income tax | 13.6 | 17.0 | 7.5 |
| Valuation allowance | 0.1 | 0.9 | 0.0 |
| Other | 2.8 | 0.1 | (0.4) |
| Total income tax expense from continuing operations | $ 155.3 | $ 138.9 | $ 112.6 |
| Income tax expense as a percent of income from continuing operations, before income taxes | 39.2% | 40.2% | 37.4% |

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. For 2015, the effective tax rate decreased as a result of a lower state consolidated tax adjustment, offset by a tax expense related to stock-based compensation.

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, 2015 will be realized in future periods.

**Deferred Income Taxes**

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

| *(millions)* *As of Dec. 31,* | | *2015* | | *2014* |
|---|---|---|---|---|
| Deferred tax liabilities [1] | | | | |
| Property related | $ | 1,519.3 | $ | 1,391.3 |
| Pension | | 86.6 | | 62.3 |
| Total deferred tax liabilities | | 1,605.9 | | 1,453.6 |
| Deferred tax assets [1] | | | | |
| Alternative minimum tax credit carryforward | | 213.5 | | 214.0 |
| Loss and credit carryforwards [2] | | 637.5 | | 566.7 |
| Other postretirement benefits | | 69.5 | | 71.5 |
| Other | | 117.5 | | 159.6 |
| Total deferred tax assets | | 1,038.0 | | 1,011.8 |
| Valuation allowance [3] | | (2.0) | | (4.6) |
| Total deferred tax assets, net of valuation allowance | | 1,036.0 | | 1,007.2 |
| Total deferred tax liability, net | | 569.9 | | 446.4 |
| Less: Current portion of deferred tax asset | | 0.0 | | (72.8) |
| Less: Long term portion of deferred tax asset | | (0.8) | | 0.0 |
| Long-term portion of deferred tax liability, net | $ | 570.7 | $ | 519.2 |

(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, 2015 that arose directly from tax deductions related to equity compensation greater than compensation recognized for financial reporting. Stockholder's equity will be increased by $2.6 million when such deferred tax assets are ultimately realized. The company uses tax law ordering when determining when excess tax benefits have been realized.
(3) During 2015, the valuation allowance related to discontinued operations decreased from $3.6 million to $1.0 million.

At Dec. 31, 2015, the company had cumulative unused federal, Florida and New Mexico NOLs for income tax purposes of $1,728.6 million, $675.2 million and $85.8 million, respectively, expiring at various times between 2025 and 2034, with the majority expiring in 2025. The federal NOL includes $121.6 million of NOLs due to the 2014 acquisition of NMGI. In addition, the company has unused general business credits of $5.8 million expiring between 2026 and 2034. During 2015, the company's available AMT credit carryforward decreased from $214.0 million to $213.5 million. The AMT 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. At Dec. 31, 2014, a $4.6 million valuation allowance had been established for state NOL carryforwards and state deferred tax assets, net of federal tax. During 2015, the valuation allowance decreased by $2.6 million. As a result of the company's sale of its 100% interest in TECO Coal, the company released a $3.6 million valuation allowance previously recorded in 2014 related to state NOL carryforwards and deferred tax assets, net of federal tax, with a corresponding write off of the gross deferred tax assets since the likelihood that the company will ever utilize those carryforwards is remote. The TECO Coal sale also generated a federal capital loss carryforward deferred tax asset of $1.0 million for which a full valuation allowance has been established due to the uncertainty of recognizing the benefit from this loss, before it expires in 2020.

**Unrecognized Tax Benefits**

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:

| *(millions)* | *2015* | *2014* | *2013* |
|---|---|---|---|
| Balance at Jan. 1, | $ 0.0 | $ 0.0 | $ 2.9 |
| Decreases due to expiration of statute of limitations | 0.0 | 0.0 | (2.9) |
| Balance at Dec. 31 | $ 0.0 | $ 0.0 | $ 0.0 |

The company recognizes interest accruals related to uncertain tax positions in "Other income" or "Interest expense", as applicable, and penalties in "Operation and maintenance other expense" in the Consolidated Statements of Income. In 2015, 2014 and 2013, the company recognized $0.0 million, $0.0 million and $(0.9) million, respectively, of pretax charges (benefits) for interest only. Additionally, the company did not have any accrued interest at Dec. 31, 2015 and 2014. No amounts have been recorded for penalties.

The company's subsidiaries join in the filing of a U.S. federal consolidated income tax return. The IRS concluded its examination of the company's 2014 consolidated federal income tax return in December 2015. The U.S. federal statute of limitations remains open for the year 2012 and forward. Years 2015 and 2016 are currently under examination by the IRS under its Compliance Assurance Program. U.S. state and foreign jurisdictions have statutes of limitations generally ranging from three to four years from the filing of an income tax return. Additionally, any state net operating losses that were generated in prior years and are still being utilized are subject to examination by state jurisdictions. 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 and foreign jurisdictions include 2005 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 qualified, non-contributory defined benefit retirement plan that covers substantially all employees. Benefits are based on employees' age, years of service and final average earnings.

Amounts disclosed for pension benefits in the following tables and discussion also include the fully-funded obligations for the SERP. The SERP is a non-qualified, non-contributory defined benefit retirement plan available to certain members of senior management.

TECO Coal participants ceased earning pension benefits on Sept. 21, 2015, the date of TECO Energy's sale of TECO Coal. As a result of the sale, a curtailment loss in the Retirement Plan was recognized in the fourth quarter of 2014. See curtailment-related line items in tables below.

### Other Postretirement Benefits

TECO Energy and its subsidiaries currently provide certain postretirement health care and life insurance benefits (Other Benefits or Other Postretirement Benefit Plan) for most 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 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 2013. TEC is amortizing the regulatory asset over the remaining average service life at the time 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, which are greater than the subsidy payments previously received by the company under Medicare Part D for its post-65 retiree prescription drug plan.

NMGC has a separate, partially-funded other postretirement benefit plan. It is not presented separately; rather, it is presented with TECO Energy's plan in the tables and discussion below. Since NMGC is allowed to recover its other postretirement benefit costs through rates, the regulated asset established prior to the acquisition for pre-acquisition-related prior service cost, actuarial loss, and transition obligation was maintained after the acquisition. This regulated asset will be amortized. See "unrecognized costs in regulated asset acquired in business combination" line item in the "Amounts recognized in accumulated other comprehensive income, pretax, and regulatory assets" table below.

Effective Jan. 1, 2015, the TECO Coal participants were terminated from the Other Postretirement Benefit Plan. As a result, the other postretirement benefit obligation for TECO Coal was eliminated as of Dec. 31, 2014. See curtailment-related line items in tables below.

## 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 and NMGC. The results of operations are not impacted.

The following table provides a detail of the change in benefit obligations and change in plan assets for combined pension plans (pension benefits) and combined other postretirement benefit plans (other benefits).

| **Obligations and Plan Assets** | **Pension Benefits** | | **Other Benefits** | |
|---|---|---|---|---|
| *(millions)* | *2015* | *2014* | *2015* | *2014* |
| **Change in benefit obligation** | | | | |
| Net benefit obligation at beginning of year | $ 728.9 | $ 666.0 | $ 201.5 | $ 208.1 |
| Service cost | 20.9 | 18.3 | 2.2 | 2.5 |
| Interest cost | 30.3 | 32.0 | 8.2 | 10.8 |
| Plan participants' contributions | 0.0 | 0.0 | 2.0 | 2.8 |
| Plan amendments | 0.0 | 0.0 | (3.7) | (23.2) |
| Actuarial loss (gain) | 5.8 | 48.3 | (0.4) | 1.5 |
| Benefits paid | (53.0) | (39.9) | (14.6) | (16.0) |
| Transfer in due to the effect of business combination | 0.0 | 0.0 | 0.0 | 26.7 |
| Plan curtailment | 0.0 | 4.0 | 0.0 | (11.7) |
| Special termination benefit | 0.0 | 0.2 | 0.0 | 0.0 |
| Net benefit obligation at end of year | $ 732.9 | $ 728.9 | $ 195.2 | $ 201.5 |
| | | | | |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | $ 648.0 | $ 593.0 | $ 18.8 | $ 0.0 |
| Actual return on plan assets | (25.5) | 46.4 | (0.6) | 0.1 |
| Employer contributions | 55.0 | 47.5 | 1.5 | (1.0) |
| Employer direct benefit payments | 0.9 | 1.0 | 13.5 | 16.0 |
| Plan participants' contributions | 0.0 | 0.0 | 2.0 | 2.8 |
| Transfer in due to acquisition | 0.0 | 0.0 | 0.0 | 16.9 |
| Benefits paid | (53.0) | (39.9) | (14.6) | (16.0) |
| Fair value of plan assets at end of year (1) | $ 625.4 | $ 648.0 | $ 20.6 | 18.8 |

(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.

At Dec. 31, the aggregate financial position for pension plans and other postretirement plans with benefit obligations in excess of plan assets was as follows:

| **Funded Status** | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(millions)* | *2015* | *2014* | *2015* | *2014* |
| Benefit obligation (PBO/APBO) | $ 732.9 | $ 728.9 | $ 195.2 | $ 201.5 |
| Less: Fair value of plan assets | 625.4 | 648.0 | 20.6 | 18.8 |
| Funded status at end of year | $ (107.5) | $ (80.9) | $ (174.6) | $ (182.7) |

The accumulated benefit obligation for all defined benefit pension plans was $686.9 million at Dec. 31, 2015 and $685.0 million at Dec. 31, 2014.

The amounts recognized in the Consolidated Balance Sheets for pension and other postretirement benefit obligations, plan assets, and unrecognized costs at Dec. 31 were as follows:

| **Amounts recognized in balance sheet** | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(millions)* | *2015* | *2014* | *2015* | *2014* |
| Regulatory assets | $ 208.2 | $ 167.4 | $ 32.4 | $ 26.6 |
| Accrued benefit costs and other current liabilities | (10.5) | (4.9) | (10.7) | (10.7) |
| Deferred credits and other liabilities | (97.0) | (76.0) | (163.9) | (172.0) |
| Accumulated other comprehensive loss (income), pretax | 55.7 | 36.3 | (41.6) | (34.6) |
| Net amount recognized at end of year | $ 156.4 | $ 122.8 | $ (183.8) | $ (190.7) |

Unrecognized gains and losses and prior service credits and costs are recorded in accumulated other comprehensive income for the non-regulated companies and regulatory assets for the regulated companies. The following table provides a detail of the unrecognized gains and losses and prior service credits and costs.

| **Amounts recognized in accumulated other comprehensive income, pretax, and regulatory assets** | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(millions)* | *2015* | *2014* | *2015* | *2014* |
| Net actuarial loss | $ 263.6 | $ 203.7 | $ 10.9 | $ 9.6 |
| Prior service cost (credit) | 0.3 | 0.0 | (25.0) | (23.6) |
| Unrecognized costs in regulated asset acquired in business combination | 0.0 | 0.0 | 4.9 | 6.0 |
| Amount recognized, pretax | $ 263.9 | $ 203.7 | $ (9.2) | $ (8.0) |

**Assumptions used to determine benefit obligations at Dec. 31:**

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | *2015* | *2014* | *2015* | *2014* |
| Discount rate | 4.688% | 4.258% | 4.669% | 4.211% |
| Rate of compensation increase—weighted | 3.87% | 3.87% | 2.50% | 3.86% |
| Healthcare cost trend rate | | | | |
| Immediate rate | n/a | n/a | 7.05% | 7.09% |
| Ultimate rate | n/a | n/a | 4.50% | 4.57% |
| Year rate reaches ultimate | n/a | n/a | 2038 | 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 | $ 9.0 | $ (7.7) |

The discount rate assumption used to determine the Dec. 31, 2015 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.

**Amounts recognized in Net Periodic Benefit Cost, OCI and Regulatory Assets**

| *(millions)* | Pension Benefits | | | Other Benefits | | |
|---|---|---|---|---|---|---|
| | *2015* | *2014* | *2013* | *2015* | *2014* | *2013* |
| Service cost | $ 20.9 | $ 18.3 | $ 18.2 | $ 2.2 | $ 2.5 | $ 2.5 |
| Interest cost | 30.3 | 32.0 | 28.9 | 8.2 | 10.8 | 9.3 |
| Expected return on plan assets | (43.3) | (41.8) | (38.4) | (1.1) | (0.3) | 0.0 |
| Amortization of: | | | | | | |
| Actuarial loss | 15.1 | 13.5 | 20.5 | 0.0 | 0.2 | 1.0 |
| Prior service (benefit) cost | (0.2) | (0.4) | (0.4) | (2.4) | (0.2) | (0.4) |
| Curtailment loss (gain) | 0.0 | 3.9 | 0.0 | 0.0 | (0.2) | 0.0 |
| Special termination benefit | 0.0 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 |
| Settlement loss | 0.0 | 0.0 | 1.0 | 0.0 | 0.0 | 0.0 |
| Net periodic benefit cost | $ 22.8 | $ 25.7 | $ 29.8 | $ 6.9 | $ 12.8 | $ 12.4 |
| New prior service cost | $ 0.0 | $ 0.0 | $ 0.0 | $ (3.7) | $ (23.6) | $ 0.0 |
| Net loss (gain) arising during the year | 74.5 | 44.1 | (75.7) | 1.3 | (9.9) | (15.6) |
| Unrecognized costs in regulated asset acquired in business combination | 0.0 | 0.0 | 0.0 | 0.0 | 6.4 | 0.0 |
| Amounts recognized as component of net periodic benefit cost: | | | | | | |
| Amortization of actuarial gain (loss) | (15.1) | (13.5) | (21.5) | 0.0 | (0.2) | (1.0) |
| Amortization of prior service (benefit) cost | 0.2 | 0.4 | 0.4 | 2.4 | 0.2 | 0.3 |
| Total recognized in OCI and regulatory assets | $ 59.6 | $ 31.0 | $ (96.8) | $ 0.0 | $ (27.1) | $ (16.3) |
| **Total recognized in net periodic benefit cost, OCI and regulatory assets** | $ 82.4 | $ 56.7 | $ (67.0) | $ 6.9 | $ (14.3) | $ (3.9) |

A curtailment loss and special termination benefits were recognized in 2014 for the Retirement Plan due to the expected sale of TECO Coal. The sale was completed in 2015. Additionally, a curtailment gain was recognized for the OPEB plan due to the termination of the TECO Coal plan effective Jan. 1, 2015.

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 $3.5 million and $0.1 million, respectively. The estimated prior service cost for the other postretirement benefit plans that will be amortized from AOCI into net periodic benefit cost over the next fiscal year is $0.5 million.

In addition, the estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year are $9.8 million. There will be an estimated $2.1 million prior service cost that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year for the other postretirement benefit plan. Additionally, $1.1 million of NMGC’s pre-acquisition regulated asset 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 | | |
|---|---|---|---|---|---|---|
| | *2015* | *2014* (1) | *2013* | *2015* | *2014* | *2013* |
| Discount rate | 4.258% | 5.118%/4.277%/4.331% | 4.196% | 4.211% | 5.096% | 4.180% |
| Expected long-term return on plan assets | 7.00% | 7.25%/7.00%/7.00% | 7.50% | 5.75 | 5.75 | n/a |
| Rate of compensation increase | 3.87% | 3.73% | 3.76% | 3.86% | 3.71% | 3.74% |
| Healthcare cost trend rate | | | | | | |
| Initial rate | n/a | n/a | n/a | 7.09% | 7.25% | 7.50% |
| Ultimate rate | n/a | n/a | n/a | 4.57% | 4.50% | 4.50% |
| Year rate reaches ultimate | n/a | n/a | n/a | 2025 | 2025 | 2025 |

(1) TECO Energy performed a valuation as of Jan. 1, 2014. TECO remeasured its Retirement Plan on Sept. 2, 2014 for the acquisition of NMGC and on Oct. 31, 2014 for the expected curtailment of TECO Coal, resulting in the respective updated discount rates and EROAs.

The discount rate assumption used to determine the 2015 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, 2015, TECO Energy's pension plan assets decreased approximately 3.5%.

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 | $ 0.4 | $ (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** | | *2015* | *2014* |
| Equity securities | 47%-53% | 53% | 50% |
| Fixed income securities | 47%-53% | 47% | 50% |
| 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 will continue to monitor the matching of 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). Investments are valued using quoted market prices on an exchange when available. Such investments are classified Level 1. In some cases where a market exchange price is available but the investments are traded in a secondary market, acceptable practical expedients are used to calculate fair value.

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, 2015 and 2014.

| *(millions)* | At Fair Value as of Dec. 31, 2015 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Using NAV [1] | Total |
| Net cash | | | | | |
| Cash | $ 1.9 | $ 0.0 | $ 0.0 | $ 0.0 | $ 1.9 |
| Accounts receivable | 14.3 | 0.0 | 0.0 | 0.0 | 14.3 |
| Accounts payable | (27.2) | 0.0 | 0.0 | 0.0 | (27.2) |
| Total net cash | (11.0) | 0.0 | 0.0 | 0.0 | (11.0) |
| Cash equivalents | | | | | |
| Money markets | 0.0 | 0.2 | 0.0 | 0.0 | 0.2 |
| Discounted notes | 0.0 | 0.7 | 0.0 | 0.0 | 0.7 |
| Short-term investment funds (STIFs) [1] | 0.0 | 0.0 | 0.0 | 12.4 | 12.4 |
| Total cash equivalents | 0.0 | 0.9 | 0.0 | 12.4 | 13.3 |
| Equity securities | | | | | |
| Common stocks | 90.9 | 0.0 | 0.0 | 0.0 | 90.9 |
| American depository receipts (ADRs) | 5.7 | 0.0 | 0.0 | 0.0 | 5.7 |
| Real estate investment trusts (REITs) | 4.8 | 0.0 | 0.0 | 0.0 | 4.8 |
| Commingled fund | 0.0 | 53.7 | 0.0 | 0.0 | 53.7 |
| Mutual funds [1] | 0.0 | 0.0 | 0.0 | 175.6 | 175.6 |
| Total equity securities | 101.4 | 53.7 | 0.0 | 175.6 | 330.7 |
| Fixed income securities | | | | | |
| Municipal bonds | 0.0 | 5.0 | 0.0 | 0.0 | 5.0 |
| Government bonds | 0.0 | 56.2 | 0.0 | 0.0 | 56.2 |
| Corporate bonds | 0.0 | 32.2 | 0.0 | 0.0 | 32.2 |
| Asset backed securities (ABS) | 0.0 | 0.3 | 0.0 | 0.0 | 0.3 |
| Mortgage-backed securities (MBS), net short sales | 0.0 | 8.7 | 0.0 | 0.0 | 8.7 |
| Collateralized mortgage obligations (CMOs) | 0.0 | 1.5 | 0.0 | 0.0 | 1.5 |
| Commingled fund [1] | 0.0 | 0.0 | 0.0 | 117.9 | 117.9 |
| Mutual fund [1] | 0.0 | 0.0 | 0.0 | 71.3 | 71.3 |
| Total fixed income securities | 0.0 | 103.9 | 0.0 | 189.2 | 293.1 |
| Derivatives | | | | | |
| Swaps | 0.0 | (0.9) | 0.0 | 0.0 | (0.9) |
| Purchased options (swaptions) | 0.0 | 1.1 | 0.0 | 0.0 | 1.1 |
| Written options (swaptions) | 0.0 | (1.0) | 0.0 | 0.0 | (1.0) |
| Total derivatives | 0.0 | (0.8) | 0.0 | 0.0 | (0.8) |
| Miscellaneous | 0.0 | 0.1 | 0.0 | 0.0 | 0.1 |
| Total | $ 90.4 | $ 157.8 | $ 0.0 | $ 377.2 | $ 625.4 |

(1) In accordance with accounting standards, certain investments that are measured at fair value using the net asset value per share practical expedient have not been classified in the fair value hierarchy. The fair value amounts in this table are to permit reconciliation of the fair value hierarchy to amounts presented in the Consolidated Balance Sheet.

| *(millions)* | At Fair Value as of Dec. 31, 2014 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Using NAV (1) | Total |
| Net cash | | | | | |
| Cash | $ 0.4 | $ 0.0 | $ 0.0 | $ 0.0 | $ 0.4 |
| Accounts receivable | 1.4 | 0.0 | 0.0 | 0.0 | 1.4 |
| Accounts payable | (5.3) | 0.0 | 0.0 | 0.0 | (5.3) |
| Total net cash | (3.5) | 0.0 | 0.0 | 0.0 | (3.5) |
| Cash equivalents | | | | | |
| Treasury bills (T bills) | 0.0 | 0.2 | 0.0 | 0.0 | 0.2 |
| Discounted notes | 0.0 | 8.8 | 0.0 | 0.0 | 8.8 |
| Short-term investment funds (STIFs) (1) | 0.0 | 0.0 | 0.0 | 7.6 | 7.6 |
| Total cash equivalents | 0.0 | 9.0 | 0.0 | 7.6 | 16.6 |
| Equity securities | | | | | |
| Common stocks | 98.0 | 0.0 | 0.0 | 0.0 | 98.0 |
| American depository receipts (ADRs) | 1.3 | 0.0 | 0.0 | 0.0 | 1.3 |
| Real estate investment trusts (REITs) | 2.5 | 0.0 | 0.0 | 0.0 | 2.5 |
| Preferred stock | 0.8 | 0.0 | 0.0 | 0.0 | 0.8 |
| Commingled fund | 0.0 | 45.6 | 0.0 | 0.0 | 45.6 |
| Mutual funds (1) | 0.0 | 0.0 | 0.0 | 171.3 | 171.3 |
| Total equity securities | 102.6 | 45.6 | 0.0 | 171.3 | 319.5 |
| Fixed income securities | | | | | |
| Municipal bonds | 0.0 | 6.1 | 0.0 | 0.0 | 6.1 |
| Government bonds | 0.0 | 47.9 | 0.0 | 0.0 | 47.9 |
| Corporate bonds | 0.0 | 22.0 | 0.0 | 0.0 | 22.0 |
| Asset backed securities (ABS) | 0.0 | 0.3 | 0.0 | 0.0 | 0.3 |
| Mortgage-backed securities (MBS), net short sales | 0.0 | 9.6 | 0.0 | 0.0 | 9.6 |
| Collateralized mortgage obligations (CMOs) | 0.0 | 2.0 | 0.0 | 0.0 | 2.0 |
| Commingled fund (1) | 0.0 | 0.0 | 0.0 | 129.2 | 129.2 |
| Mutual fund (1) | 0.0 | 0.0 | 0.0 | 98.6 | 98.6 |
| Total fixed income securities | 0.0 | 87.9 | 0.0 | 227.8 | 315.7 |
| Derivatives | | | | | |
| Short futures | 0.0 | (0.3) | 0.0 | 0.0 | (0.3) |
| Purchased options (swaptions) | 0.0 | 0.7 | 0.0 | 0.0 | 0.7 |
| Written options (swaptions) | 0.0 | (0.8) | 0.0 | 0.0 | (0.8) |
| Total derivatives | 0.0 | (0.4) | 0.0 | 0.0 | (0.4) |
| Miscellaneous | 0.0 | 0.1 | 0.0 | 0.0 | 0.1 |
| Total | $ 99.1 | $ 142.2 | $ 0.0 | $ 406.7 | $ 648.0 |

(1) In accordance with accounting standards, certain investments that are measured at fair value using the net asset value per share practical expedient have not been classified in the fair value hierarchy. The fair value amounts in this table are to permit reconciliation of the fair value hierarchy to amounts presented in the Consolidated Balance Sheet.

The following list details the pricing inputs and methodologies used to value the investments in the pension plan:

- The primary pricing inputs in determining the fair value of the Level 1 assets are closing quoted prices in active markets.
- The methodology and inputs used to value the investment in the equity commingled fund are broker dealer quotes sourced by State Street Custody System. The fund holds primarily international equity securities that are actively traded in over-the-counter markets. The fund honors subscription and redemption activity on an “as of” basis.
- The money markets are valued at cost due to their short-term nature. Discounted notes are valued at amortized cost.
- 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 CMO 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.
- 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.
- The STIF is valued at NAV as determined by JP Morgan. The funds are open-end investments. Additionally, 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.
- The primary pricing inputs in determining the equity 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.
- The primary pricing input in determining the fair value of the fixed asset mutual fund is its NAV. It is an unregistered open-ended mutual fund.
- The fixed income commingled fund is a private fund valued at NAV. 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.

Additionally, the unqualified SERP had $43.5 million and $0.9 million of assets as of Dec. 31, 2015 and 2014, respectively. Since the plan is unqualified, its assets are included in the "Deferred charges and other assets" line item in TECO Energy's Consolidated Balance Sheets rather than being netted with the related liability. The fund holds investments in a money market fund, which is valued at cost due to its short-term nature, making this a level 2 asset. The SERP was fully funded as of Dec. 31, 2015.

**Other Postretirement Benefit Plan Assets**

NMGC's other postretirement benefits plan had $20.6 million and $18.8 million of assets as of Dec. 31, 2015 and 2014, respectively. The majority of the assets are valued at the cash surrender value of NMGC participant life insurance policies and are considered Level 2 assets. In accordance with NMPRC requirements, NMGC must fund to a trust, on an annual basis, an amount equal to the other postretirement expense allowed in its last base rate case.

**Contributions**

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 were based on a percentage of the funding target until 2013, 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 August 2014, the President signed into law HAFTA, which modified MAP-21. HAFTA and MAP-21 provide 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 HAFTA and MAP-21. In November 2015, the President signed into law the Bipartisan Budget Act of 2015, which extended pension funding relief of MAP-21 and HAFTA through 2022.

The qualified pension plan's actuarial value of assets, including credit balance, was 120.1% of the Pension Protection Act funded target as of Jan. 1, 2015 and is estimated at 114.1% of the Pension Protection Act funded target as of Jan. 1, 2016.

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 $55.0 million and $47.5 million of contributions to this plan in 2015 and 2014, respectively, which met the minimum funding requirements for both 2015 and 2014. These amounts are reflected in the "Other" line on the Consolidated Statements of Cash Flows. The company estimates its contribution in 2016 to be $37.4 million and expects to make contributions from 2017 to 2020 in the range of $12.2 to $44.6 million per year based on current assumptions. These contributions are in excess of the minimum required contribution under ERISA guidelines.

The company made contributions of $43.4 million and $1.2 million to the SERP in 2015 and 2014, respectively. The company's contribution in October 2015 to the SERP's trust was made in order to fully fund its SERP obligation following the signing of the Merger Agreement with Emera. The execution of the Merger Agreement constituted a potential change in control under the trust; therefore, TECO Energy is required to maintain such funding as of the end of each calendar year, including 2015. The fully funded amount is equal to the aggregate present value of all benefits then in pay status under the SERP plus the current value of benefits that would become payable under the SERP to current participants. Since the SERP is fully funded, the company does not expect to make significant contributions to this plan in 2016.

The company funds its other postretirement benefits periodically 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 July 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. In 2016, the company expects to make contributions of about $14.3 million. This includes $3.6 million that NMGC is required to fund to its trust in accordance with NMPRC requirements. 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** |
|---|---|---|
| 2016 | $ 77.8 | $ 11.5 |
| 2017 | 49.5 | 11.9 |
| 2018 | 52.7 | 12.5 |
| 2019 | 59.2 | 13.0 |
| 2020 | 54.9 | 13.3 |
| 2021-2025 | 299.1 | 68.6 |

**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 Jan. 1, 2015, employer matching contributions were 70% of eligible participant contributions with additional incentive match of up to 30% of eligible participant contributions based on the achievement of certain operating company financial goals. During the period from April 2013 to December 2014, 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, 2015, 2014 and 2013, the company and its subsidiaries recognized expense totaling $11.1 million, $13.1 million and $11.3 million, respectively, related to the matching contributions made to this plan.

## 6. Short-Term Debt

At Dec. 31, 2015 and Dec. 31, 2014, the following credit facilities and related borrowings existed:

**Credit Facilities**

| | *Dec. 31, 2015* | | | *Dec. 31, 2014* | | |
|---|---|---|---|---|---|---|
| *(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 | $ 0.0 | $ 0.5 | $ 325.0 | $ 12.0 | $ 0.6 |
| 3-year accounts receivable facility [3] | 150.0 | 61.0 | 0.0 | 150.0 | 46.0 | 0.0 |
| TECO Energy/TECO Finance: | | | | | | |
| 5-year facility [2][4] | 300.0 | 163.0 | 0.0 | 300.0 | 50.0 | 0.0 |
| New Mexico Gas Company: | | | | | | |
| 5-year facility [2] | 125.0 | 23.0 | 1.7 | 125.0 | 31.0 | 1.7 |
| **Total** | $ 900.0 | $ 247.0 | $ 2.2 | $ 900.0 | $ 139.0 | $ 2.3 |

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) Prior to Mar. 24, 2015, this was a 1-year facility. This 3-year facility matures Mar. 23, 2018.
(4) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.

At Dec. 31, 2015, these credit facilities required commitment fees ranging from 12.5 to 30.0 basis points. The weighted-average interest rate on borrowings outstanding under the credit facilities at Dec. 31, 2015 and 2014 was 1.29% and 1.16%, respectively.

*Tampa Electric Company Accounts Receivable Facility*

On Mar. 24, 2015, TEC and TRC amended and restated their $150 million accounts receivable collateralized borrowing facility in order to (i) appoint The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch (BTMU), as Program Agent, replacing the previous Program Agent, Citibank, N.A., (ii) add new lenders, and (iii) extend the scheduled termination date from Apr. 14, 2015 to Mar. 23, 2018, by entering into (a) an Amended and Restated Purchase and Contribution Agreement dated as of Mar. 24, 2015 between TEC and TRC and (b) a Loan and Servicing Agreement dated as of Mar. 24, 2015, among TEC as Servicer, TRC as Borrower, certain lenders named therein and BTMU, as Program Agent (the Loan Agreement). Pursuant to the Loan Agreement, TRC will pay program and liquidity fees, which total 65 basis points as of Dec. 31, 2015. Interest rates on the borrowings are based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to, at TEC's option, either the BTMU's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank deposit rate (if available) plus a margin. In addition, under the terms of the Loan Agreement, TEC has pledged as collateral a pool of receivables equal to the borrowings outstanding in the case of default. TEC continues to service, administer and collect the pledged receivables, which are classified as receivables on the balance sheet. As of Dec. 31, 2015, TEC and TRC were in compliance with the requirements of the Loan Agreement.

*TECO Energy Credit Agreement Assigned to and Assumed by NMGC*

On Dec. 17, 2013, TECO Energy entered into a $125 million bank credit facility, pursuant to which it was the initial party to the Credit Agreement (the NMGC Credit Agreement). TECO Energy had no rights or obligations to borrow under the NMGC Credit Agreement, which was 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, on Sept. 2, 2014, TECO Energy designated NMGC as the borrower under the NMGC Credit Agreement by delivering a Joinder and Release Agreement duly executed by TECO Energy and NMGC, whereupon (i) NMGC became 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 ceased to be a party to the NMGC Credit Agreement and any 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) allows 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, allows 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) allows 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) allows 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.

On Sept. 30, 2014, NMGC entered into an amendment of the NMGC Credit Agreement, which reallocated commitments among the lenders and made certain other technical changes.

*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) extended 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) continued to allow TEC, as borrower, 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.

On Sept. 30, 2014, TEC entered into an amendment of its $325 million bank credit facility, which reallocated commitments among the lenders and made certain other technical changes.

*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) extended 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 (viii) made 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. Amendment No. 1 was entered into to accommodate the acquisition of NMGI, as described in **Note 21** 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 closed, 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) changed the definition of Permitted Liens to permit the acquisition of a significant subsidiary that has outstanding secured debt and made other changes matching the corresponding covenant in the Bridge Facility. TECO Energy and TECO Finance entered into a $1.075 billion senior unsecured bridge credit agreement on June 24, 2013, among TECO Energy as guarantor, TECO Finance as borrower, Morgan Stanley Senior Funding, Inc. (Morgan Stanley) as administrative agent, sole lead arranger and sole book runner, and Morgan Stanley together with nine other banks as lenders in the Bridge Facility.

On Sept. 30, 2014, the TECO Credit Facility was amended to increase total commitments to $300 million and to reallocate commitments among the lenders.

## 7. Long-Term Debt

At Dec. 31, 2015, total long-term debt had a carrying amount of $3,850.2 million and an estimated fair market value of $4,061.6 million. At Dec. 31, 2014, total long-term debt had a carrying amount of $3,628.5 million and an estimated fair market value of $3,987.8 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 wholly 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 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 2016 through 2020 and thereafter are as follows:

### Long-Term Debt Maturities

| *As of Dec. 31, 2015 (millions)* | *2016* | *2017* | *2018* | *2019* | *2020* | *Thereafter* | *Total Long-Term Debt* |
|---|---|---|---|---|---|---|---|
| TECO Finance | $ 250.0 | $ 300.0 | $ 250.0 | $ 0.0 | $ 300.0 | $ 0.0 | $ 1,100.0 |
| Tampa Electric | 83.3 | 0.0 | 254.2 | 0.0 | 0.0 | 1,666.7 | 2,004.2 |
| PGS | 0.0 | 0.0 | 50.0 | 0.0 | 0.0 | 211.7 | 261.7 |
| NMGC | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 270.0 | 270.0 |
| NMGI | 0.0 | 0.0 | 0.0 | 50.0 | 0.0 | 150.0 | 200.0 |
| Total long-term debt maturities | $ 333.3 | $ 300.0 | $ 554.2 | $ 50.0 | $ 300.0 | $ 2,298.4 | $ 3,835.9 |

*Issuance of TECO Finance Floating Rate Notes due 2018*

On Apr. 10, 2015, TECO Finance completed an offering of $250 million aggregate principal amount of floating rate notes due 2018 (the 2018 Notes), which are guaranteed by TECO Energy. The 2018 Notes were sold at par and mature on Apr. 10, 2018. The 2018 Notes bear interest at a floating rate that is reset quarterly based on the three-month LIBOR plus 60 basis points. The 2018 Notes are not subject to redemption prior to maturity. The 2018 Notes are effectively subordinated to existing and future liabilities of TECO Energy's subsidiaries to their respective creditors, and also are effectively subordinated to any secured debt that TECO Finance and TECO Energy incur to the extent of the value of the assets securing that indebtedness.

The offering resulted in net proceeds to TECO Finance (after deducting underwriting discounts and commissions and estimated offering expenses) of approximately $248.6 million. TECO Finance used these net proceeds to repay borrowings under the TECO Finance credit facility and to fund a portion of the payment of $191 million of TECO Finance notes that matured in May 2015.

*Issuance of Tampa Electric Company 4.20% Notes due 2045*

On May 20, 2015, TEC completed an offering of $250 million aggregate principal amount of 4.20% Notes due May 15, 2045 (the TEC 2015 Notes). The TEC 2015 Notes were sold at 99.814% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, estimated offering expenses and before settlement of interest rate swaps) of approximately $246.8 million. Net proceeds were used to repay short-term debt and for general corporate purposes. Until Nov. 15, 2044, TEC may redeem all or any part of the TEC 2015 Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of the TEC 2015 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the TEC 2015 Notes to be redeemed, discounted at an applicable treasury rate (as defined in the indenture), plus 20 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Nov. 15, 2044, TEC may, at its option, redeem the TEC 2015 Notes, in whole or in part, at 100% of the principal amount of the TEC 2015 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

*Issuance of Tampa Electric Company 4.35% Notes due 2044*

On May 15, 2014, TEC completed an offering of $300 million aggregate principal amount of 4.35% Notes due 2044 (the TEC 2014 Notes). The TEC 2014 Notes were sold at 99.933% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, estimated offering expenses and before settlement of interest rate swaps) of approximately $296.6 million. Net proceeds were used to repay short-term debt and for general corporate purposes. TEC may redeem all or any part of the TEC 2014 Notes at its option at any time and from time to time before Nov. 15, 2043 at a redemption price equal to the greater of (i) 100% of the principal amount of TEC 2014 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the notes to be redeemed, discounted at an applicable treasury rate (as defined in the indenture), 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 Nov. 15, 2043, TEC may at its option redeem the TEC 2014 Notes, in whole or in part, at 100% of the principal amount of the notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

*Issuance of New Mexico Gas Intermediate Senior Unsecured Notes*

On Sept. 2, 2014, NMGI completed an offering of $50 million aggregate principal amount of 2.71% Series A Senior Unsecured Notes due July 30, 2019 (the NMGI Series A 2014 Notes) and $150 million aggregate principal amount of 3.64% Series B Senior Unsecured Notes due July 30, 2024 (the NMGI Series B 2014 Notes and, with the NMGI Series A 2014 Notes, the NMGI 2014 Notes). The NMGI 2014 Notes were sold at 100% of par. The offering resulted in net proceeds to NMGI (after deducting underwriting discounts, commissions and estimated offering expenses) of approximately $198.4 million. Net proceeds were used to repay existing indebtedness and for general corporate purposes. NMGI may redeem all or any part of the NMGI 2014 Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of NMGI 2014 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the NMGI notes to be redeemed, discounted at an applicable reinvestment yield (as defined in the note purchase agreement), plus 50 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. The NMGI 2014 Notes were issued in a private placement that was not subject to the registration requirements of the Securities Act of 1933.

*Issuance of New Mexico Gas Company Senior Unsecured 3.54 % Notes due 2026*

On Sept. 2, 2014, NMGC completed an offering of $70 million aggregate principal amount of 3.54% Senior Unsecured Notes due July 30, 2026 (the NMGC 2014 Notes). The NMGC 2014 Notes were sold at 100% of par. The offering resulted in net proceeds to NMGC (after deducting underwriting discounts, commissions and estimated offering expenses) of approximately $69.3 million. Net proceeds were used to repay existing indebtedness and for general corporate purposes. NMGC may redeem all or any part of the NMGC 2014 Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of NMGC 2014 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the notes to be redeemed, discounted at an applicable reinvestment yield (as defined in the note purchase agreement), plus 50 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. The NMGC 2014 Notes were issued in a private placement that was exempt from the registration requirements of the Securities Act of 1933.

*Amendment of New Mexico Gas Company 4.87 % Notes due 2021*

On Feb. 8, 2011, NMGC issued secured notes in an aggregate principal amount of $200 million (NMGC 2011 Notes), maturing Feb. 8, 2021. The NMGC 2011 Notes were issued in a private placement that was exempt from the registration requirements of the Securities Act of 1933.

On July 16, 2014, NMGC received approvals from the noteholders of the NMGC 2011 Notes to release the collateral securing the NMGC 2011 Notes by amending the existing note purchase agreement. The amendments to the note purchase agreement were subject to the approval of the NMPRC, and on Oct. 22, 2014, NMGC received the required NMPRC approval of the amendments. On Oct. 30, 2014, the amendments became effective, the collateral securing the NMGC 2011 Notes was released and other technical changes were made to the NMGC 2011 Notes.

*Purchase in Lieu of Redemption of Revenue Refunding Bonds*

On Mar. 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 Mar. 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 Mar. 19, 2008 to Mar. 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 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 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 Mar. 26, 2008 to Sept. 1, 2013. TEC is responsible for payment of the interest and principal associated with the Series 2007 B HCIDA Bonds.

As of Dec. 31, 2015, $232.6 million of bonds purchased in lieu of redemption were held by the trustee at the direction of TEC to provide an opportunity to evaluate refinancing alternatives.

At Dec. 31, 2015 and 2014, TECO Energy had the following long-term debt outstanding:

| **Long-Term Debt** *(millions)* | | *Due* | *2015* | *2014* |
|---|---|---|---|---|
| **TECO Finance** | Notes [1][2] : 6.75% [3] | 2015 | $ 0.0 | $ 191.2 |
| | 4.00% [3] | 2016 | 250.0 | 250.0 |
| | 6.57% [3] | 2017 | 300.0 | 300.0 |
| | Floating rate notes | 2018 | 250.0 | 0.0 |
| | 5.15% [3] | 2020 | 300.0 | 300.0 |
| | Total long-term debt of TECO Finance | | 1,100.0 | 1,041.2 |
| **Tampa Electric** | Installment contracts payable [4] : | | | |
| | 5.65% Refunding bonds | 2018 | 54.2 | 54.2 |
| | Variable rate bonds repurchased in 2008 [5] | 2020 | 0.0 | 0.0 |
| | 5.15% Refunding bonds repurchased in 2013 [6] | 2025 | 0.0 | 0.0 |
| | 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][2] : 6.25% | 2015-2016 | 83.3 | 166.7 |
| | 6.10% | 2018 | 200.0 | 200.0 |
| | 5.40% | 2021 | 231.7 | 231.7 |
| | 2.60% | 2022 | 225.0 | 225.0 |
| | 6.55% | 2036 | 250.0 | 250.0 |
| | 6.15% | 2037 | 190.0 | 190.0 |
| | 4.10% | 2042 | 250.0 | 250.0 |
| | 4.35% | 2044 | 290.0 | 290.0 |
| | 4.20% | 2045 | 230.0 | 0.0 |
| | Total long-term debt of Tampa Electric | | 2,004.2 | 1,857.6 |
| **PGS** | Notes [2][3] : 6.10% | 2018 | 50.0 | 50.0 |
| | 5.40% | 2021 | 46.7 | 46.7 |
| | 2.60% | 2022 | 25.0 | 25.0 |
| | 6.15% | 2037 | 60.0 | 60.0 |
| | 4.10% | 2042 | 50.0 | 50.0 |
| | 4.35% | 2044 | 10.0 | 10.0 |
| | 4.20% | 2045 | 20.0 | 0.0 |
| | Total long-term debt of PGS | | 261.7 | 241.7 |
| **NMGI** | Notes [2][3] : 2.71% | 2019 | 50.0 | 50.0 |
| | 3.64% | 2024 | 150.0 | 150.0 |
| | Total long-term debt of NMGI | | 200.0 | 200.0 |
| **NMGC** | Notes [2][3] : 4.87% | 2021 | 200.0 | 200.0 |
| | 3.54% | 2026 | 70.0 | 70.0 |
| | Total long-term debt of NMGC | | 270.0 | 270.0 |
| | Total long-term debt of TECO Energy | | 3,835.9 | 3,610.5 |
| Unamortized debt discount, net | | | 14.3 | 18.0 |
| Total carrying amount of long-term debt | | | 3,850.2 | 3,628.5 |
| Less amount due within one year | | | 333.3 | 274.5 |
| Total long-term debt | | | $ 3,516.9 | $ 3,354.0 |

(1) Guaranteed by TECO Energy.
(2) These long-term debt agreements contain various restrictive financial covenants.
(3) These securities are subject to redemption in whole or in part, at any time, at the option of the issuer.
(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**

**Pending Merger with Emera**

On Sept. 4, 2015, TECO Energy and Emera entered into the Merger Agreement. Upon closing of the Merger, which is expected to occur in the summer of 2016, each issued and outstanding share of TECO Energy common stock will be cancelled and converted automatically into the right to receive $27.55 in cash, without interest.

The Merger Agreement with Emera restricts TECO Energy and its subsidiaries, without Emera's prior written consent, from issuing equity or equity equivalents and from paying quarterly cash dividends in excess of levels agreed upon in the Merger Agreement until the Merger occurs or the Merger Agreement is terminated.

See **Note 21** for additional information regarding the pending Merger.

**Public Offering of 15.5 million in Common Shares**

On July 1, 2014, the company entered into an underwriting agreement with Morgan Stanley & Co. LLC, as representative of the several underwriters named therein, pursuant to which the company agreed to offer and sell 15.5 million shares of its common stock in an underwritten public offering at a public offering price of $18.10 per share. The company received approximately $271 million in net proceeds from the offering after underwriting fees and offering expenses. The shares were delivered to the underwriters on July 8, 2014.

Pursuant to the terms of the underwriting agreement, the company granted the underwriters a 30-day option to purchase up to an additional 2.3 million shares. The company received approximately $21 million of net proceeds when the underwriters exercised this option for an additional 1.2 million shares.

The company used the net proceeds from the offering to fund, in part, the acquisition of NMGI and for general corporate purposes.

**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. The amendment reduced the number of shares of common stock subject to grants to 4.0 million shares (a reduction of 3.0 million shares), removed the cap on shares available for stock grant, placed various limitations on the terms of awards granted under the 2010 Plan, removed the ability to make awards to consultants of the company and reapproved 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 in amounts ranging between 0% and 150% of the original grant. Beginning in 2015, the total awards for performance-based restricted stock vest based on achievement of earnings growth, with the ability to earn more shares based on total return of TECO Energy common stock compared to a peer group of utility stocks. The 2015 performance-based grants can vest in amounts ranging between 0% and 200% 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 Merger Agreement with Emera contains provisions regarding the vesting of outstanding grants which would apply upon closing of the Merger.

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 | *2015* | *2014* | *2013* |
|---|---|---|---|
| Assumptions applicable to performance-based restricted stock | | | |
| Risk-free interest rate | 0.83% | 0.68% | 0.41% |
| Expected lives (in years) | 3 | 3 | 3 |
| Expected stock volatility | 14.78% | 17.36% | 19.04% |
| Dividend yield | 3.98% | 5.13% | 4.83% |

In 2015, 2014 and 2013, 0.7 million, 0.8 million and 0.7 million shares of restricted stock were granted, respectively, with weighted-average fair value per share of $22.96, $14.69 and $17.21, respectively. The total fair market value of awards vesting during 2015, 2014 and 2013 was $7.5 million, $3.6 million and $3.5 million, respectively, which includes stock grants, time-vested restricted stock and performance-based restricted stock. As of Dec. 31, 2015, there was $13.2 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)* | *2015* | *2014* | *2013* |
|---|---|---|---|
| Compensation costs (1) | $ 13.1 | $ 12.7 | $ 13.5 |
| Income tax benefits (1) | 5.1 | 4.9 | 5.2 |
| Excess tax benefits (2) | 0.0 | 0.4 | 0.0 |

(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 $2.9 million, $2.7 million and $2.4 million for the periods ended Dec. 31, 2015, 2014 and 2013, respectively. Cash received from option exercises under all share-based payment arrangements was $9.4 million, $10.8 million and $6.7 million for the periods ended Dec. 31, 2015, 2014 and 2013, respectively. The income tax benefit realized from stock option exercises was $1.1 million, $1.0 million and $0.8 million for the periods ended Dec. 31, 2015, 2014 and 2013, 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, 2014 | 668 | $ 17.56 | 1,515 | $ 15.44 |
| Granted | 213 | $ 21.34 | 445 | $ 23.72 |
| Vested | (273) | $ 17.96 | (626) | $ 15.94 |
| Forfeited | (19) | $ 17.78 | (43) | $ 16.05 |
| Nonvested balance at Dec. 31, 2015 | 589 | $ 18.74 | 1,291 | $ 18.06 |

(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, 2014 | 840 | $ 16.32 | | |
| Granted | 0 | $ 0.00 | | |
| Exercised | (580) | $ 16.30 | | |
| Cancelled | (6) | $ 18.87 | | |
| Outstanding balance at Dec. 31, 2015 [(1)] | 254 | $ 16.30 | 1 | $ 2.6 |
| Exercisable at Dec. 31, 2015 [(1)] | 254 | $ 16.30 | 1 | $ 2.6 |
| Available for future grant at Dec. 31, 2015 | 2,429 | | | |

(1) Option prices are $16.30 per share.

**Direct Stock Purchase and Dividend Reinvestment Plan**

In September 2014, the Direct Stock Purchase and Dividend Plan amended and restated the 1992 Dividend Reinvestment and Common Stock Purchase Plan. TECO Energy purchased shares on the open market for this plan in 2015, 2014 and 2013, resulting in no increase in shares outstanding.

**10. Other Comprehensive Income**

TECO Energy reported the following OCI (loss) for the years ended Dec. 31, 2015, 2014 and 2013, related to changes in the fair value of cash flow hedges and amortization of unrecognized benefit costs associated with the company's benefit plans:

| *(millions)* | *Gross* | *Tax* | *Net* |
|---|---|---|---|
| **2015** | | | |
| Unrealized gain (loss) on cash flow hedges | $ 4.3 | $ (1.5) | $ 2.8 |
| Reclassification from AOCI to net income (1) | 1.4 | (0.7) | 0.7 |
| Gain (Loss) on cash flow hedges | 5.7 | (2.2) | 3.5 |
| Amortization of unrecognized benefit costs and other (2) | 3.4 | (1.3) | 2.1 |
| Change in benefit obligation due to valuation (3) | (15.5) | 5.7 | (9.8) |
| Recognized cost due to settlement (4) | 12.1 | (4.4) | 7.7 |
| Total other comprehensive income (loss) | $ 5.7 | $ (2.2) | $ 3.5 |
| **2014** | | | |
| Unrealized gain (loss) on cash flow hedges | $ (0.5) | $ 0.2 | $ (0.3) |
| Reclassification from AOCI to net income (1) | 1.6 | (0.6) | 1.0 |
| Gain (Loss) on cash flow hedges | 1.1 | (0.4) | 0.7 |
| Amortization of unrecognized benefit costs and other (2) | (4.8) | 1.8 | (3.0) |
| Increase in unrecognized postemployment costs (5) | (12.9) | 4.7 | (8.2) |
| Change in benefit obligation due to valuation (6) | 12.6 | (4.6) | 8.0 |
| Total other comprehensive income (loss) | $ (4.0) | $ 1.5 | $ (2.5) |
| **2013** | | | |
| Unrealized gain (loss) on cash flow hedges | $ 1.0 | $ (0.4) | $ 0.6 |
| Reclassification from AOCI to net income (1) | 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 (2) | 23.6 | (8.8) | 14.8 |
| Recognized costs due to settlement | 2.6 | (1.0) | 1.6 |
| Total other comprehensive income (loss) | $ 28.5 | $ (10.7) | $ 17.8 |

(1) Related to interest rate contracts in Interest expense and commodity contracts recognized in Income (loss) from discontinued operations.
(2) Related to postretirement and postemployment benefits. See **Note 5** for additional information.
(3) Related to the transfer of employees and their associated postretirement benefits from TEC to TSI, the TECO Energy shared services company. TEC recognized these deferred costs as regulatory assets, whereas TSI recognized them in AOCI.
(4) Related to the settlement of the TECO Coal black lung obligation at the closing of the sale. See **Note 19** for additional information.
(5) Amounts reflect an out-of-period adjustment related to TECO Coal's unfunded black lung liability.
(6) Includes an adjustment to eliminate TECO Coal's OPEB liability. See **Note 5** for additional information.

**Accumulated Other Comprehensive Loss**

| *(millions) Dec. 31,* | 2015 | 2014 |
|---|---|---|
| Unamortized pension losses and prior service credits (1) | $ (34.2) | $ (22.5) |
| Unamortized other benefit gains, prior service costs and transition obligations (2) | 25.6 | 13.9 |
| Net unrealized losses from cash flow hedges (3) | (3.6) | (7.1) |
| Total accumulated other comprehensive loss | $ (12.2) | $ (15.7) |

(1) Net of tax benefit of $21.5 million and $13.8 million as of Dec. 31, 2015 and 2014, respectively.
(2) Net of tax expense of $16.1 million and $8.3 million as of Dec. 31, 2015 and 2014, respectively. The Dec. 31, 2014 balance included a $7.7 million loss related to TECO Coal's unfunded black lung liability that was reclassified from AOCI to net income from discontinued operations upon the settlement of the black lung obligation at the sale date. See **Note 5**.
(3) Net of tax benefit of $2.3 million and $4.5 million as of Dec. 31, 2015 and 2014, 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)* | *2015* | *2014* | *2013* [(1)] |
|---|---|---|---|
| **Basic earnings per share** | | | |
| Net income from continuing operations | $ 241.2 | $ 206.4 | $ 188.7 |
| Amount allocated to nonvested participating shareholders | (0.7) | (0.7) | (0.6) |
| Income before discontinued operations available to common shareholders—Basic | $ 240.5 | $ 205.7 | $ 188.1 |
| Income (loss) from discontinued operations | $ (67.7) | $ (76.0) | $ 9.0 |
| Amount allocated to nonvested participating shareholders | 0.0 | 0.0 | 0.0 |
| Income (loss) from discontinued operations —Basic | $ (67.7) | $ (76.0) | $ 9.0 |
| Net income | $ 173.5 | $ 130.4 | $ 197.7 |
| Amount allocated to nonvested participating shareholders | (0.7) | (0.7) | (0.6) |
| Net income available to common shareholders—Basic | $ 172.8 | $ 129.7 | $ 197.1 |
| Average common shares outstanding—Basic | 233.1 | 223.1 | 215.0 |
| Earnings per share from continuing operations available to common shareholders—Basic | $ 1.03 | $ 0.92 | $ 0.88 |
| Earnings per share from discontinued operations available to common shareholders—Basic | (0.29) | (0.34) | 0.04 |
| **Earnings per share attributable to TECO Energy available to common shareholders—Basic** | **$ 0.74** | **$ 0.58** | **$ 0.92** |
| **Diluted earnings per share** | | | |
| Net income from continuing operations | $ 241.2 | $ 206.4 | $ 188.7 |
| Amount allocated to nonvested participating shareholders | (0.7) | (0.7) | (0.6) |
| Income before discontinued operations available to common shareholders—Diluted | $ 240.5 | $ 205.7 | $ 188.1 |
| Income (loss) from discontinued operations | $ (67.7) | $ (76.0) | $ 9.0 |
| Amount allocated to nonvested participating shareholders | 0.0 | 0.0 | 0.0 |
| Income (loss) from discontinued operations available to common shareholders—Diluted | $ (67.7) | $ (76.0) | $ 9.0 |
| Net income | $ 173.5 | $ 130.4 | $ 197.7 |
| Amount allocated to nonvested participating shareholders | (0.7) | (0.7) | (0.6) |
| Net income available to common shareholders—Diluted | $ 172.8 | $ 129.7 | $ 197.1 |
| Unadjusted average common shares outstanding—Diluted | 233.1 | 223.1 | 215.0 |
| Assumed conversion of stock options, unvested restricted stock and contingent performance shares, net | 1.4 | 0.6 | 0.5 |
| Average common shares outstanding—Diluted | 234.5 | 223.7 | 215.5 |
| Earnings per share from continuing operations available to common shareholders—Diluted | $ 1.03 | $ 0.92 | $ 0.88 |
| Earnings per share from discontinued operations available to common shareholders—Diluted | (0.29) | (0.34) | 0.04 |
| **Earnings per share available to common shareholders—Diluted** | **$ 0.74** | **$ 0.58** | **$ 0.92** |
| Anti-dilutive shares | 0.0 | 0.0 | 0.0 |

(1) All prior periods presented reflect the classification of TECO Coal 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. The company believes the claims in which the company or a subsidiary of the company is a defendant in the pending actions described below are without merit and intends to defend the matters vigorously. The company is unable at this time to estimate the possible loss or range of loss with respect to these matters. 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.

*Tampa Electric Legal Proceedings*

A 36-year-old man died from mesothelioma in March 2014. His estate and his family sued Tampa Electric as a result. The man allegedly suffered exposure to asbestos dust brought home by his father and grandfather, both of whom had been employed as insulators and worked at various job sites throughout the Tampa area. Plaintiff's case against Tampa Electric and 14 other defendants had alleged, among other things, negligence, strict liability, household exposure, loss of consortium, and wrongful death. Tampa Electric has agreed to a settlement which resolved the case in its entirety. The settlement is not material to the company's financial position as of Dec. 31, 2015.

A 33-year-old man made contact with a primary line in June 2013, suffering severe burns. He and his wife sued Tampa Electric as a result. The man apparently made contact with the line as he was attempting to trim a tree at a local residence. Plaintiffs' case against Tampa Electric alleged, among other things, negligence and loss of consortium. Tampa Electric has agreed to a settlement which resolved the case in its entirety. The settlement is not material to the company's financial position as of Dec. 31, 2015.

*Peoples Gas 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. 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 and a PGS contractor involved in the project, seeking damages for his injuries, remains pending, with a trial currently expected in late 2016.

*New Mexico Gas Company Legal Proceedings*

In February 2011, NMGC experienced gas shortages due to weather-related interruptions of electric service, weather-related problems on the systems of various interstate pipelines and in gas fields that are the sources of gas supplied to NMGC, and high weather-driven usage. This gas supply disruption and high usage resulted in the declaration of system emergencies by NMGC causing involuntary curtailments of gas utility service to approximately 28,700 customers (residential and business).

In March 2011, a customer purporting to represent a class consisting of all "32,000 [sic] customers" who had their gas utility service curtailed during the early-February system emergencies filed a putative class action lawsuit against NMGC. In March 2011, the Town of Bernalillo, New Mexico, purporting to represent a class consisting of all "New Mexico municipalities and governmental entities who have suffered damages as a result of the natural gas utility shut off" also filed a putative class action lawsuit against NMGC, four of its officers, and John and Jane Does at NMGC. In July 2011, the plaintiff in the Bernalillo class action filed an amended complaint to add an additional plaintiff purporting to represent a class of all "similarly situated New Mexico private businesses and enterprises."

In September 2015, a settlement was reached with all the named plaintiff class representatives in both of the class actions. The settlements were on an individual basis and not a class basis. The settlements are not material to the company's financial position as of Dec. 31, 2015.

In addition to the two settled class actions described above, 18 insurance carriers have filed two subrogation lawsuits for monies paid to their insureds as a result of the curtailment of natural gas service in February 2011. In January 2016, the judge entered summary judgement in favor of NMGC and all of the subrogation lawsuits were dismissed. The insurance carriers subsequently filed a timely appeal of the summary judgement.

*TECO Guatemala Holdings, LLC v. The Republic of Guatemala*

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

On Apr. 18, 2014, Guatemala filed an application for annulment of the entire Award (or, alternatively, certain parts of the Award) pursuant to applicable ICSID rules.

Also on Apr. 18, 2014, TGH separately filed an application for partial annulment of the Award on the basis of certain deficiencies in the ICSID Tribunal's determination of the amount of TGH's damages. If TGH's application is successful, TGH will be able to seek additional damages from Guatemala in a new arbitration proceeding.

While the duration of the annulment proceedings is uncertain, a hearing was held in October 2015, with a decision by the ad hoc committee expected in mid- to late-2016. Pending the outcome of annulment proceedings, results to date do not reflect any benefit of this decision.

*Proceedings in connection with the Pending Merger with Emera*

Twelve securities class action lawsuits were filed against the company and its directors by holders of TECO Energy securities following the announcement of the Emera transaction. Eleven suits were filed in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida. They alleged that TECO Energy's board of directors breached its fiduciary duties in agreeing to the Merger Agreement and sought to enjoin the Merger. In addition, several of these suits alleged that one or more of TECO Energy, Emera and an Emera affiliate aided and abetted such alleged breaches. The securities class action lawsuits have been consolidated per court order. Since the consolidation, two of the complaints have been amended. One of those complaints has added a claim against the individual defendants for breach of fiduciary duty to disclose. The twelfth suit was filed in the Middle District of Florida Federal Court and has subsequently been voluntarily dismissed.

The company also received two separate shareholder demand letters from purported shareholders of the company. Both of these letters demanded that the company maximize shareholder value and remove alleged conflicts of interest as well as eliminate allegedly preclusive deal protection devices. One of the letters also demanded that the company refrain from consummating the transaction with Emera. Both of these demand letters have subsequently been withdrawn.

In November 2015, the parties to the lawsuits entered into a Memorandum of Understanding with the various shareholder plaintiffs to settle, subject to court approval, all of the pending shareholder lawsuits challenging the proposed Merger. As a result of the Memorandum of Understanding, the company made additional disclosures related to the proposed Merger in a proxy supplement. Per the terms of the Memorandum of Understanding, the parties will negotiate a settlement agreement and submit it to the court for approval after the Merger is complete. There can be no assurance that the parties will ultimately enter into a stipulation of settlement or that the court will approve the settlement even if the parties were to enter into a stipulation of settlement.

**PGS Compliance Matter**

In 2015, FPSC staff presented PGS with a summary of alleged safety rule violations, many of which were identified during PGS' implementation of an action plan it instituted as a result of audit findings cited by FPSC audit staff in 2013. Following the 2013 audit and 2015 discussions with FPSC staff, PGS took immediate and significant corrective actions. The FPSC audit staff published a follow-up audit report that acknowledged the progress that had been made and found that further improvements were needed. As a result of this report, the Office of Public Counsel (OPC) filed a petition with the FPSC pointing to the violations of rules for safety inspections seeking fines or possible refunds to customers by PGS. On Feb. 25, 2016, the FPSC staff issued a notice informing PGS that the staff would be making a recommendation to the FPSC to initiate a show cause proceeding against PGS for alleged safety rule violations, with total potential penalties of up to $3.9 million. PGS is continuing to work with the OPC and FPSC staff to resolve the issues.

**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, 2015, TEC has estimated its ultimate financial liability to be $33.9 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Deferred credits and other liabilities" 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 rates.

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 for capacity payments and long-term leases, primarily for building space, vehicles, office equipment and heavy equipment. Rental expense for these leases included in “Regulated operations and maintenance – Other”, “Operation & maintenance other expense – Other” and “Discontinued Operations” on the Consolidated Statements of Income for the years ended Dec. 31, 2015, 2014 and 2013 totaled $15.3 million, $13.7 million and $7.6 million, respectively. In addition, the company has other purchase obligations, including Tampa Electric’s outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year, capacity payments under PPAs, and other net purchase obligations/commitments at Dec. 31, 2015:

| *(millions)* | *Capacity Payments* | *Operating Leases*[1] | *Net Purchase Obligations/Commitments*[1] | *Total* |
|---|---|---|---|---|
| Year ended Dec. 31: | | | | |
| 2016 | $ 14.6 | $ 7.7 | $ 222.5 | $ 244.8 |
| 2017 | 9.9 | 7.1 | 21.5 | 38.5 |
| 2018 | 10.1 | 6.4 | 9.6 | 26.1 |
| 2019 | 0.0 | 5.7 | 9.7 | 15.4 |
| 2020 | 0.0 | 5.4 | 4.7 | 10.1 |
| Thereafter | 0.0 | 18.6 | 20.0 | 38.6 |
| Total future minimum payments | $ 34.6 | $ 50.9 | $ 288.0 | $ 373.5 |

(1) Reflects those contractual obligations and commitments considered material to the respective operating companies, individually. The table above excludes payment obligations under contractual agreements of Tampa Electric, PGS and NMGC for fuel, fuel transportation and power purchases which are recovered from customers under regulatory clauses.

**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, 2015 are as follows:

| *(millions)* | Year of Expiration | | | *Maximum* | |
|---|---|---|---|---|---|
| *Guarantees for the Benefit of:* | *2016* | *2017-2020* | *After [1] 2020* | *Theoretical Obligation* | *Liabilities Recognized at Dec. 31, 2015* |
| **TECO Energy** | | | | | |
| Fuel sales and transportation [2] | $ 0.0 | $ 0.0 | $ 92.9 | $ 92.9 | $ 0.0 |
| Letters of indemnity - coal mining permits [3] | 90.0 | 0.0 | 0.0 | 90.0 | 0.0 |
| | $ 90.0 | $ 0.0 | $ 92.9 | $ 182.9 | $ 0.0 |

| *(millions)* | Year of Expiration | | | *Maximum* | |
|---|---|---|---|---|---|
| *Letter of Credit for the Benefit of:* | *2016* | *2017-2020* | *After [1] 2020* | *Theoretical Obligation* | *Liabilities Recognized at Dec. 31, 2015 [4]* |
| **TEC** | $ 0.0 | $ 0.0 | $ 0.5 | $ 0.5 | $ 0.1 |
| **NMGC** | $ 0.0 | $ 0.0 | $ 1.7 | $ 1.7 | $ 0.0 |

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2020.
(2) The amounts shown represent the maximum theoretical amounts of cash collateral that TECO Energy would be required to post in the event of a downgrade below investment grade for its long-term debt ratings by the major credit rating agencies. Liabilities recognized represent the associated potential obligation related to net derivative liabilities under these agreements at Dec. 31, 2015. See **Note 16** for additional information.
(3) These letters of indemnity guarantee payments to certain surety companies that issued reclamation bonds to the Commonwealths of Kentucky and Virginia in connection with TECO Coal's mining operations. Payments to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder, TECO Coal, does not pay the surety. The amounts shown represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies. As discussed in **Note 19**, TECO Coal was sold on Sept. 21, 2015 to Cambrian. Pursuant to the SPA, Cambrian is obligated to file applications required in connection with the change of control with the appropriate governmental entities. Once the applicable governmental agency deems each application to be acceptable, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond secured by the TECO Energy indemnity for that permit. Until the bonds secured by TECO Energy's indemnity are released, TECO Energy's indemnity will remain effective. At the date of sale in September 2015, the letters of indemnity guaranteed $93.8 million. The company is working with Cambrian on the process to replace the bonds and expects the process to be completed in 2016. Pursuant to the SPA, Cambrian has the obligation to indemnify and hold TECO Energy harmless from any losses incurred that arise out of the coal mining permits during the period commencing on the closing date through the date all permit approvals are obtained.
(4) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy, TEC or NMGC under these agreements at Dec. 31, 2015. The obligations under these letters of credit include certain accrued injuries and damages when a letter of credit covers the failure to pay these claims.

**Financial Covenants**

In order to utilize their respective bank credit facilities, TECO Energy and its subsidiaries must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy and its subsidiaries have certain restrictive covenants in specific agreements and debt instruments. At Dec. 31, 2015, TECO Energy and its subsidiaries were in compliance with all required financial covenants.

## 13. Related Party Transactions

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 for the year ended Dec. 31, 2013 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, 2015, 2014 and 2013. No material balances were payable as of Dec. 31, 2015 or 2014.

## 14. Segment Information

TECO Energy is primarily an electric and gas utility holding company. Its diversified activities have been classified as discontinued operations. 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 segment’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.

Tampa Electric provides retail electric utility services to almost 719,000 customers in West Central Florida. PGS is engaged in the purchase and distribution of natural gas for approximately 361,000 residential, commercial, industrial and electric power generation customers in the State of Florida. NMGC is engaged in the purchase and distribution of natural gas for more than 516,000 residential, commercial, industrial customers in the State of New Mexico.

| *(millions)* | Tampa Electric | PGS | NMGC [4] | TECO Coal [2] | Other [4],[5] | Eliminations [5] | TECO Energy |
|---|---|---|---|---|---|---|---|
| **2015** | | | | | | | |
| Revenues—external | $2,014.9 | $ 401.5 | $ 316.5 | $ 0.0 | $ 10.6 | $ 0.0 | $2,743.5 |
| Sales to affiliates | 3.4 | 6.0 | 0.0 | 0.0 | 0.1 | (9.5) | 0.0 |
| Total revenues | 2,018.3 | 407.5 | 316.5 | 0.0 | 10.7 | (9.5) | 2,743.5 |
| Depreciation and amortization | 256.7 | 56.8 | 33.8 | 0.0 | 1.7 | 0.0 | 349.0 |
| Total interest charges [1] | 95.1 | 14.5 | 13.0 | 0.0 | 65.1 | (1.3) | 186.4 |
| Internally allocated interest [1] | 0.0 | 0.0 | 0.0 | 0.0 | 1.3 | (1.3) | 0.0 |
| Provision for income taxes | 143.6 | 21.9 | 15.4 | 0.0 | (25.6) | 0.0 | 155.3 |
| Net income from continuing operations | 241.0 | 35.3 | 24.1 | 0.0 | (59.2) | 0.0 | 241.2 |
| Discontinued operations, net of tax | 0.0 | 0.0 | 0.0 | (69.6) | 1.9 | 0.0 | (67.7) |
| Net income | 241.0 | 35.3 | 24.1 | (69.6) | (57.3) | 0.0 | 173.5 |
| Goodwill | 0.0 | 0.0 | 408.4 | 0.0 | 0.0 | 0.0 | 408.4 |
| Total assets | 7,020.7 | 1,137.4 | 1,231.3 | 0.0 [3] | 1,947.9 | (2,376.2) [6] | 8,961.1 |
| Capital expenditures | 592.6 | 94.0 | 48.7 | 3.7 | 0.7 | 0.0 | 739.7 |
| **2014** | | | | | | | |
| Revenues—external | $2,019.9 | $ 398.5 | $ 137.5 | $ 0.0 | $ 10.5 | $ 0.0 | $2,566.4 |
| Sales to affiliates | 1.1 | 1.1 | 0.0 | 0.0 | 0.2 | (2.4) | 0.0 |
| Total revenues | 2,021.0 | 399.6 | 137.5 | 0.0 | 10.7 | (2.4) | 2,566.4 |
| Depreciation and amortization | 248.6 | 54.0 | 11.0 | 0.0 | 1.7 | 0.0 | 315.3 |
| Total interest charges [1] | 92.8 | 13.8 | 4.2 | 0.0 | 66.1 | (5.8) | 171.1 |
| Internally allocated interest [1] | 0.0 | 0.0 | 0.0 | 0.0 | 5.8 | (5.8) | 0.0 |
| Provision for income taxes | 133.2 | 22.7 | 7.1 | 0.0 | (24.1) | 0.0 | 138.9 |
| Net income from continuing operations | 224.5 | 35.8 | 10.5 | 0.0 | (64.4) | 0.0 | 206.4 |
| Discontinued operations, net of tax | 0.0 | 0.0 | 0.0 | (82.0) | 6.0 | 0.0 | (76.0) |
| Net income | 224.5 | 35.8 | 10.5 | (82.0) | (58.4) | 0.0 | 130.4 |
| Goodwill | 0.0 | 0.0 | 408.3 | 0.0 | 0.0 | 0.0 | 408.3 |
| Total assets | 6,565.4 | 1,082.8 | 1,237.2 | 227.7 [3] | 1,611.6 | (1,998.5) [6] | 8,726.2 |
| Capital expenditures | 582.1 | 88.9 | 18.2 | 14.6 | 0.0 | 0.0 | 703.8 |
| **2013** | | | | | | | |
| Revenues—external | $1,949.6 | $ 392.7 | $ 0.0 | $ 0.0 | $ 12.8 | $ 0.0 | $2,355.1 |
| Sales to affiliates | 0.9 | 0.8 | 0.0 | 0.0 | 0.5 | (2.2) | 0.0 |
| Total revenues | 1,950.5 | 393.5 | 0.0 | 0.0 | 13.3 | (2.2) | 2,355.1 |
| Depreciation and amortization | 238.8 | 51.5 | 0.0 | 0.0 | 1.5 | 0.0 | 291.8 |
| Total interest charges [1] | 91.8 | 13.5 | 0.0 | 0.0 | 63.9 | (7.8) | 161.4 |
| Internally allocated interest [1] | 0.0 | 0.0 | 0.0 | 0.0 | 7.8 | (7.8) | 0.0 |
| Provision for income taxes | 116.9 | 21.9 | 0.0 | 0.0 | (26.2) | 0.0 | 112.6 |
| Net income from continuing operations | 190.9 | 34.7 | 0.0 | 0.0 | (36.9) | 0.0 | 188.7 |
| Discontinued operations, net of tax | 0.0 | 0.0 | 0.0 | 9.0 | 0.0 | 0.0 | 9.0 |
| Net income | 190.9 | 34.7 | 0.0 | 9.0 | (36.9) | 0.0 | 197.7 |
| Total assets | 6,126.9 | 1,021.2 | 0.0 | 316.3 [3] | 1,739.2 | (1,755.6) [6] | 7,448.0 |
| Capital expenditures | 422.3 | 79.0 | 0.0 | 22.4 | 2.4 | 0.0 | 526.1 |

(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 2015, 2014 and 2013 were at a pretax rate of 6.00%, 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 Coal and certain charges at Other, including Parent and TECO Diversified, that directly relate to TECO Coal or TECO Guatemala. See **Note 19**.

(3) The carrying value of mineral rights as of Dec. 31, 2015, 2014 and 2013 was $0.0 million, $10.9 million and $12.1 million, respectively.
(4) NMGI is included in the Other segment.
(5) Certain prior year amounts have been reclassified to conform to current year presentation.
(6) Amounts primarily relate to consolidated tax eliminations.

**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.

Prior to the sale of TECO Coal on Sept. 21, 2015, TECO Energy had recognized AROs for reclamation and site restoration obligations principally associated with coal mining, storage and transfer facilities at TECO Coal. The majority of obligations were related to environmental remediation and restoration activities for coal-related operations. At Dec. 31, 2014, these obligations totaled $22.5 million and were classified as Liabilities Associated with Assets Held for Sale on TECO Energy's Consolidated Balance Sheet.

TECO Energy's regulated utilities must file depreciation and dismantlement studies periodically and receive approval from the FPSC or NMPRC 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, PGS and NMGC, 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, 2015 and 2014, these obligations totaled $6.8 million and $6.1 million, respectively.

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

| *(millions)* | *Dec. 31, 2015* | *Dec. 31, 2014* |
|---|---|---|
| Beginning balance | $ 6.1 | $ 28.6 |
| Additional liabilities | 0.9 | 0.1 |
| Revisions to estimated cash flows | (0.5) | 0.2 |
| Acquisition of NMGC | 0.0 | 0.8 |
| Reclassification to liabilities associated with assets held for sale | 0.0 | (22.5) |
| Other [(1)] | 0.3 | (1.1) |
| Ending balance | $ 6.8 | $ 6.1 |

(1) 2015 includes $0.3 million accretion recorded as a deferred regulatory asset. 2014 includes $(1.3) million of activity associated with TECO Coal and classified as discontinued operations and $0.2 million 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, PGS and NMGC; and
- To limit the exposure to interest rate fluctuations on debt securities at TECO Energy and its affiliates.

TECO Energy and its affiliates use derivatives only to reduce normal operating and market risks, not for speculative purposes. The regulated utilities' 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 and NMPRC, 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, 2015, all of the company's physical contracts qualify for the NPNS exception.

The derivatives that are designated as cash flow hedges at Dec. 31, 2015 and 2014 are reflected on the company's Consolidated Balance Sheets and classified accordingly as current and long term assets and liabilities on a net basis as permitted by their respective master netting agreements. Derivative assets totaled $0.2 and $0.0 million as of Dec. 31, 2015 and 2014, respectively, and are included in "Prepayments and other current assets" on the Consolidated Balance Sheet. Derivative liabilities totaled $26.2 million and $42.7 million as of Dec. 31, 2015 and 2014, respectively. There are minor offset amount differences between the gross derivative assets and liabilities and the net amounts presented on the Consolidated Balance Sheets. There was no collateral posted with or received from any counterparties.

All of the derivative asset and liabilities at Dec. 31, 2015 and 2014 are designated as hedging instruments, which primarily are derivative hedges of natural gas contracts to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers. The corresponding effect of these natural gas related derivatives on the regulated utilities' fuel recovery clause mechanism is reflected on the Consolidated Balance Sheets as current and long term regulatory assets and liabilities. Based on the fair value of the instruments at Dec. 31, 2015, net pretax losses of $23.9 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The Dec. 31, 2015 and 2014 balance in AOCI related to the cash flow hedges and interest rate swaps (unsettled and previously settled) is presented in **Note 10**.

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, 2015, 2014 and 2013, all hedges were effective. The derivative after-tax effect on OCI and the amount of after-tax gain or loss reclassified from AOCI into earnings for the years ended Dec. 31, 2015, 2014 and 2013 is presented in **Note 10**. These gains and losses were the result of interest rate contracts for TEC and diesel fuel derivatives related to TECO Coal operations. The locations of the reclassifications to income were reflected in "Interest expense" for TEC and "Income (loss) from discontinued operations" for TECO Coal.

The maximum length of time over which the company is hedging its exposure to the variability in future cash flows extends to Nov. 30, 2017 for financial natural gas contracts. The following table presents the company's derivative volumes that, as of Dec. 31, 2015, are expected to settle during the 2016 and 2017 fiscal years:

| *(millions)* | **Natural Gas Contracts (MMBTUs)** | |
|---|---|---|
| Year | **Physical** | **Financial** |
| 2016 | 0.0 | 38.4 |
| 2017 | 0.0 | 5.1 |
| Total | 0.0 | 43.5 |

The company is exposed to credit risk by 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. 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, 2015, 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 generally do not require a nonperformance risk adjustment 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.

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 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.

## 17. Fair Value Measurements

### Items Measured at Fair Value on a Recurring Basis

Accounting guidance governing fair value measurements and disclosures provides that fair value represents the amount that would be received in selling an asset or the amount that would be paid in transferring a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that is determined based upon assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, accounting guidance also establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1: Observable inputs, such as quoted prices in active markets;

Level 2: Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and

Level 3: Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities are measured at fair value based on one or more of the following three valuation techniques noted under accounting guidance:

*(A)* <u>Market approach</u>: Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities;

*(B)* <u>Cost approach</u>*:* Amount that would be required to replace the service capacity of an asset (replacement cost); and

*(C)* <u>Income approach</u>*:* Techniques to convert future amounts to a single present amount based upon market expectations (including present value techniques, option-pricing and excess earnings models).

The fair value of financial instruments is determined by using various market data and other valuation techniques.

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, 2015 and 2014. 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.

**Recurring Fair Value Measures**

| | As of Dec. 31, 2015 | | | |
|---|---|---|---|---|
| *(millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | |
| Natural gas derivatives | $ 0.0 | $ 0.2 | $ 0.0 | $ 0.2 |
| **Liabilities** | | | | |
| Natural gas derivatives | $ 0.0 | $ 26.2 | $ 0.0 | $ 26.2 |

| | As of Dec. 31, 2014 | | | |
|---|---|---|---|---|
| *(millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Liabilities** | | | | |
| Natural gas derivatives | $ 0.0 | $ 42.7 | $ 0.0 | $ 42.7 |

The natural gas derivatives are OTC swap and option instruments. Fair values of swaps and options are estimated utilizing the market and income approach, respectively. The price of swaps is calculated using observable NYMEX quoted closing prices of exchange-traded futures. The price of options is calculated using the Black-Scholes model with observable exchange-traded futures as the primary pricing inputs to the model. Additional inputs to the model include historical volatility, discount rate, and a locational basis adjustment to NYMEX. The resulting prices are applied to the notional quantities of active swap and option positions to determine the 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, 2015, the fair value of derivatives was not materially affected by nonperformance risk. There were no Level 3 assets or liabilities for the periods presented.

See **Notes 5, 7 and 19** for information regarding the fair value of the company's pension plan investments, long-term debt, and asset impairment charge, respectively.

**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.

Tampa Electric 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 157 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 variable interests. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. Tampa Electric 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, and have the obligation or right to absorb losses or benefits and hence remain the primary beneficiaries. As a result, Tampa Electric is not required to consolidate any of these entities. Tampa Electric purchased $33.6 million, $25.7 million and $22.1 million, under these PPAs for the three years ended Dec. 31, 2015, 2014 and 2013, respectively.

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, Assets Held for Sale and Asset Impairments

### TECO Coal

In 2013, TECO Coal temporarily idled some of its mines due to the softened coal market. As a result, the company performed impairment analyses in the fourth quarter of 2013 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 were recoverable; therefore, no impairment charge was deemed necessary in 2013. 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.

In September 2014, the Board of Directors of TECO Energy authorized management to actively pursue the sale of TECO Coal. As a result of this and other factors, the TECO Coal segment was accounted for as an asset held for sale and reported as a discontinued operation beginning in the third quarter of 2014. All periods have been adjusted to reflect the reclassification of results from operations to discontinued operations for TECO Coal and certain charges at Parent that directly relate to the sale of TECO Coal.

In 2014, the company recorded impairment charges totaling $115.9 million pretax to write down the held-for-sale TECO Coal assets to their implied fair value based on the price specified in an agreement of sale entered into in October 2014, which agreement had conditions to closing that were not satisfied, less estimated costs of the transaction. In the second quarter of 2015, based on management's assessment of current market conditions and discussions with interested parties, an additional impairment charge of $78.6 million pretax was recorded, which included the estimated selling costs associated with the transaction completed in September 2015. The fair value measurements were considered Level 2 measurements since the market is not active as defined by accounting standards (i.e. transactions for these assets are too infrequent to provide pricing information on an ongoing basis). None of these impairments had cash flow impacts. The asset impairment charges are recorded in the "Income (loss) from discontinued operations" line item in the Consolidated Statements of Income and the "Asset impairment" line item in the Consolidated Statements of Cash Flows for the years ended Dec. 31, 2014 and 2015.

On Sept. 21, 2015, TECO Energy's subsidiary, TECO Diversified, entered into the SPA and completed the sale of all of its ownership interest in TECO Coal to Cambrian. The SPA did not provide for an up-front purchase payment, but provides for future contingent consideration of up to $60 million that may be paid yearly through 2019 if certain coal benchmark prices reach certain levels. The 2015 benchmark price was not reached and no contingent consideration payment was triggered. TECO Energy retains certain deferred tax assets and personnel-related liabilities, but all other TECO Coal assets and liabilities, including working capital, asset retirement obligations and workers compensation reserves, were transferred in the transaction. The retained liabilities included pension liability, which was fully funded at Sept. 30, 2015, and severance agreements, which were accrued at June 30, 2015 and paid in the third quarter of 2015. Letters of indemnity related to TECO Coal reclamation bonds will remain in effect until the bonds are replaced by Cambrian, which is expected to be completed in 2016 (see description of guarantees in **Note 12**). The company recorded a loss on sale of $10.0 million pretax, which is reflected in discontinued operations in the company's Consolidated Condensed Statement of Income, primarily to write off an after-tax settlement charge of $7.7 million related to the unfunded black lung obligations previously recorded in AOCI. Transaction-related costs of $12.3 million pretax, comprised of $2.5 million of legal and other consultant costs and $9.8 million of severance and other employee costs, were accrued at June 30, 2015 and reflected in discontinued operations in the company's Consolidated Condensed Statement of Income. The transaction-related costs were paid in 2015, with the exception of a minor amount of severance payments.

Since the closing of the sale, TECO Energy has not and will not have influence over operations of TECO Coal, therefore the contingent payments are not considered to meet the definition of direct cash flows under the applicable discontinued operations FASB guidance.

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

**Assets held for sale**

| *(millions)* | Dec. 31, 2014 |
|---|---|
| Current assets | $ 109.6 |
| Property, plant and equipment, net and other long-term assets | 59.8 |
| Total assets held for sale | $ 169.4 |

**Liabilities associated with assets held for sale**

| *(millions)* | |
|---|---|
| Current liabilities | $ 39.4 |
| Long-term liabilities | 65.4 |
| Total liabilities associated with assets held for sale | $ 104.8 |

**TECO Guatemala**

In 2012, TECO Guatemala completed the sale of its interests in the Alborada and San José power stations, and related solid fuel handling and port facilities in Guatemala. All periods presented reflect the classification of results from operations for TECO Guatemala and certain charges at Parent that directly relate to TECO Guatemala as discontinued operations. While TECO Energy and its subsidiaries 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 (see **Note 12**). The 2015 charges shown in the table below are legal costs associated with that claim. Additionally, in March 2014, an indemnification provision for an uncertain tax position at TCAE that was provided for in the 2012 purchase agreement was reversed due to a favorable final decision by the highest court in Guatemala, resulting in the income from operations amount shown in the table below.

**Combined components of income from discontinued operations**

The following table provides selected components of discontinued operations related to TECO Coal and TECO Guatemala:

| **Components of income from discontinued operations** *(millions)* | *2015* | *2014* | *2013* |
|---|---|---|---|
| Revenues—TECO Coal | $ 200.4 | $ 443.6 | $ 496.2 |
| Income (loss) from operations—TECO Coal | (16.9) | (13.9) | 5.4 |
| Income (loss) from operations—TECO Guatemala | (0.8) | 4.4 | (0.2) |
| Loss on impairment—TECO Coal | (78.6) | (115.9) | 0.0 |
| Loss on sale—TECO Coal | (10.0) | 0.0 | 0.0 |
| Income (loss) from discontinued operations—TECO Coal | (105.5) | (129.8) | 5.4 |
| Income (loss) from discontinued operations—TECO Guatemala | (0.8) | 4.4 | (0.2) |
| Income (loss) from discontinued operations | (106.3) | (125.4) | 5.2 |
| Provision (benefit) for income taxes | (38.6) | (49.4) | (3.8) |
| Income (loss) from discontinued operations, net | $ (67.7) | $ (76.0) | $ 9.0 |

**20. Goodwill**

The following table presents the changes in the carrying amount of goodwill for the years ended Dec. 31, 2015, 2014 and 2013.

| ***(millions)*** | NMGC | Total |
|---|---|---|
| Balance as of Dec. 31, 2013 | $ 0.0 | $ 0.0 |
| Acquisition of NMGC | 408.3 | 408.3 |
| Balance as of Dec. 31, 2014 | 408.3 | 408.3 |
| Measurement period adjustments (1) | 0.1 | 0.1 |
| Balance as of Dec. 31, 2015 | $ 408.4 | $ 408.4 |

(1) Due to immateriality, the measurement period adjustment was not applied retrospectively to the opening balance sheet.

The goodwill on the company's balance sheet related to the NMGC segment was recorded upon acquisition of NMGI on Sept. 2, 2014 (see **Note 21**). Under the accounting guidance for goodwill, goodwill is not subject to amortization. Rather, goodwill is subject to an annual assessment for impairment at the reporting unit level. Reporting units are generally determined at the operating segment level or 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. Since NMGC is the lowest level of identifiable cash flows, this is the level at which goodwill is tested. Entities assessing goodwill for impairment have the option of first performing a qualitative assessment to determine whether a quantitative assessment is necessary. If an entity performs the qualitative assessment, but determines that it is more likely than not that its fair value is less than its carrying amount or if an entity bypasses the qualitative assessment, a quantitative two-step, fair value-based test is performed. The first step compares the fair value of the reporting unit to its carrying amount, including goodwill. If the carrying amount of the reporting unit exceeds its fair value, the second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation accounting guidance in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and a charge to operating expense. TECO Energy reviews recorded goodwill at least annually (during the fourth quarter) for each reporting unit.

The fair value for NMGC was determined in the fourth quarter using a weighted combination of a discounted cash flow analysis, a market multiple analysis, and a comparable transactions analysis. The discounted cash flow analysis relies on management's best estimate of NMGC's projected cash flows. It includes an estimate of NMGC's terminal value based on these expected cash flows using the Gordon Growth Formula, which derives a valuation using an assumed perpetual annuity based on the entity's residual cash flows. The discount rate is a market participant rate based on a peer group of publicly traded comparable companies and represents the weighted average cost of capital of comparable companies. The market multiples analysis utilizes multiples of business enterprise value to EBITDA of comparable public companies in estimating fair value. The comparable transaction analysis identified comparable company acquisitions within the industry and calculates the implied EBITDA multiple from the transaction, which is then applied to the last-twelve-months EBITDA of the subject company. Significant assumptions used in estimating the fair value include discount and growth rates, utility sector market performance and transactions, projected operating and capital cash flows and the calculation of the terminal value.

The company determined the fair value of NMGC exceeds the book value and related goodwill carrying amounts at Dec. 31, 2015 and 2014, resulting in no impairment charge. Adverse changes in assumptions described above could result in a future material impairment of NMGC's goodwill.

**21. Mergers and Acquisitions**

**Pending Merger with Emera Inc.**

On Sept. 4, 2015, TECO Energy and Emera entered into the Merger Agreement. Upon closing of the Merger, TECO Energy will become a wholly owned indirect subsidiary of Emera.

Upon the terms and subject to the conditions set forth in the Merger Agreement, which was unanimously approved and adopted by the board of directors of TECO Energy, at the effective time, Merger Sub will merge with and into TECO Energy with TECO Energy continuing as the surviving corporation.

Pursuant to the Merger Agreement, upon the closing of the Merger, which is expected to occur in the summer of 2016, each issued and outstanding share of TECO Energy common stock will be cancelled and converted automatically into the right to receive $27.55 in cash, without interest (Merger Consideration). This represents an aggregate purchase price of approximately $10.4 billion including assumption of approximately $3.9 billion of debt.

The closing of the Merger is subject to certain conditions, including, among others, (i) approval of TECO Energy shareholders representing a majority of the outstanding shares of TECO Energy common stock (which approval was obtained at the special meeting of shareholders held on Dec. 3, 2015), (ii) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period (which expired on Feb. 5, 2016), (iii) receipt of all required regulatory approvals, including from the FERC, the NMPRC and the Committee on Foreign Investment in the United States (which, with respect to the FERC, was obtained on Jan. 20, 2016) (iv) the absence of any law or judgment that prevents, makes illegal or prohibits the closing of the Merger, (v) the absence of any material adverse effect with respect to TECO Energy and (vi) subject to certain exceptions, the accuracy of the representations and warranties of, and compliance with covenants by, each of the parties to the Merger Agreement.

The Merger Agreement contains customary representations, warranties and covenants of TECO Energy, Emera and Merger Sub. The Merger Agreement contains covenants by TECO Energy, among others, that (i) TECO Energy will conduct its business in the ordinary course during the interim period between the execution of the Merger Agreement and the closing of the Merger and (ii) TECO Energy will not engage in certain transactions during such interim period. The Merger Agreement contains covenants by Emera, among others, that Emera will use its reasonable best efforts to take all actions necessary to obtain all governmental and regulatory approvals.

In addition, the Merger Agreement requires Emera (i) to maintain TECO Energy's historic levels of community involvement and charitable contributions and support in TECO Energy's existing service territories, (ii) to maintain TECO Energy's headquarters in Tampa, Florida, (iii) to honor current union contracts in accordance with their terms and (iv) to provide each continuing non-union employee, for a period of two years following the closing of the Merger, with a base salary or wage rate no less favorable than, and incentive compensation and employee benefits, respectively, substantially comparable in the aggregate to those, that they received as of immediately prior to the closing.

TECO Energy is also subject to a "no shop" restriction that limits its ability to solicit alternative acquisition proposals or provide nonpublic information to, and engage in discussion with, third parties.

The Merger Agreement contains certain termination rights for both TECO Energy and Emera. Either party may terminate the Merger Agreement if (i) the closing of the Merger has not occurred by Sept. 30, 2016 (subject to a 6-month extension if required to obtain necessary regulatory approvals), (ii) a law or judgment preventing or prohibiting the closing of the Merger has become final, (iii) TECO Energy's shareholders do not approve the Merger or (iv) TECO Energy's board of directors changes its recommendation so that it is no longer in favor of the Merger. If either party terminates the Merger Agreement because TECO Energy's board of directors changes its recommendation, TECO Energy must pay Emera a termination fee of $212.5 million. If the Merger Agreement is terminated under certain other circumstances, including the failure to obtain required regulatory approvals, Emera must pay TECO Energy a termination fee of $326.9 million.

During the year ended Dec. 31, 2015, TECO Energy incurred approximately $17.0 million pretax of incremental transaction-related costs, which are included in "Operations and maintenance other expense" on the Consolidated Condensed Statements of Income.

**Acquisition of New Mexico Gas Company**

***Description of Transaction***

On Sept. 2, 2014, the company completed the acquisition of NMGI contemplated by the acquisition agreement dated May 25, 2013 by and among the company, NMGI and Continental Energy Systems LLC. As a result of that acquisition, the company acquired all of the capital stock of NMGI. NMGI is the parent company of NMGC. The aggregate purchase price was $950 million, which included the assumption of $200 million of senior secured notes at NMGC, plus certain working capital adjustments.

***Description of NMGC***

On the acquisition date, NMGC, with approximately 720 employees, served more than 513,000 customers, predominately residential, in New Mexico with the majority located in the Central Rio Grande Corridor region, which is one of the fastest growing regions in the state. The company served 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.

***Strategic Rationale for Acquisition***

- A transformative transaction that immediately added more than 513,000 customers in a single state.
- Provides an opportunity for TECO Energy's experienced management team to share marketing expertise to a new and growing service territory, and for both companies to share best practices to support growth.
- Diversifies TECO Energy's operating footprint.
- Provides immediate to near-term shareholder and customer benefits through organic growth opportunities.

***Acquisition-Related Regulatory Matters***

NMGC is a rate-regulated natural gas utility subject to the regulation of the NMPRC, including with respect to its rates, service standards, accounting, securities issuances, construction of major new transmission and distribution facilities and other matters affecting, directly or indirectly, the provision of natural gas sales and transportation services to NMGC's customers.

In May 2014, TECO Energy reached a settlement with the New Mexico Industrial Energy Consumers (which represents large customers), the New Mexico Attorney General's office (which represents the New Mexico residential and small business customers) and the U.S. Department of Energy. As part of this settlement of the application for approval of the acquisition by the NMPRC, TECO Energy agreed, among other things, to:

- freeze rates for NMGC customers until the end of 2017,
- credit NMGC customers with a $2 million rate credit to customer bills in 2015, increasing to $4 million per year in 2016 and each year after 2016 until NMGC's next rate case,
- cap job losses in New Mexico at 99 over three years, many of which will be through attrition,
- maintain the NMGC name and headquarters in Albuquerque,
- support new economic development opportunities designed to attract new businesses to New Mexico through maintaining good service and reasonable customer rates,
- maintain or increase NMGC's current level of community involvement and support, and
- own NMGC for at least 10 years.

On Aug. 13, 2014, the NMPRC approved the acquisition with the conditions set forth in the settlement agreements described above. The transaction closed on Sept. 2, 2014.

***Purchase Price***

The total consideration in the acquisition was as follows:

| **Consideration Transferred** *(millions)* | | |
|---|---|---|
| Cash paid to seller | $ | 530.1 |
| Cash paid to settle long-term debt, including accrued interest and fees | | 219.9 |
| Long-term debt assumed | | 200.0 |
| Total consideration transferred, excluding cash and working capital adjustments | $ | 950.0 |

***Purchase Price Allocation***

The majority of NMGI's assets acquired and liabilities assumed relate to deferred income taxes associated with its NOL. These were recorded in accordance with the applicable accounting guidance. Additionally, the company paid off the existing outstanding debt at NMGI and issued $200 million of new NMGI debt at closing. Since the refinancing took place at closing, face value approximated fair value.

The majority of NMGC's operations are subject to the rate-setting authority of the NMPRC and are accounted for pursuant to U.S. GAAP, including the accounting guidance for regulated operations. Rate-setting and cost recovery provisions currently in place for NMGC's regulated operations provide revenues derived from costs, including a return on investment of assets and liabilities included in rate base. Except for long-term debt, the ARO, derivatives, OPEB plans, and deferred taxes, fair values of tangible and intangible assets and liabilities subject to these rate-setting provisions approximate their carrying values. Accordingly, assets acquired and liabilities assumed and pro-forma financial information do not reflect any net adjustments related to these amounts. The difference between fair value and pre-merger carrying amounts for long-term debt, derivatives, and the OPEB plan for regulated operations were recorded as regulatory assets or liabilities.

The excess of the purchase price over the estimated fair values of assets acquired and liabilities assumed was recognized as goodwill at the acquisition date. The goodwill reflects the value paid primarily for opportunities for growth, synergies and an improved risk profile. Goodwill resulting from the acquisition was allocated entirely to the NMGC segment. Goodwill of $146.1 million related to the formation of NMGC in 2009 is tax deductible. The incremental goodwill recognized as part of this transaction is not deductible for income tax purposes, and as such, no deferred taxes were recorded related to this portion of the goodwill.

The final purchase price allocation of the acquisition of NMGI and NMGC was as follows:

| **Purchase Price Allocation** *(millions)* | | |
|---|---|---|
| Current assets [(1)] | $ | 48.7 |
| Property, plant and equipment | | 616.4 |
| OPEB regulatory asset | | 6.4 |
| Debt-related regulatory asset | | 23.9 |
| Goodwill | | 408.4 |
| Deferred tax assets | | 52.8 |
| Other assets | | 29.3 |
| Total assets | $ | 1,185.9 |
| Current liabilities | $ | (38.2) |
| Long-term debt fair value adjustment and interest assumed | | (22.7) |
| Cost of removal regulatory liability | | (100.6) |
| Deferred tax liabilities | | (60.8) |
| OPEB liability | | (9.8) |
| Deferred credits and other liabilities | | (3.8) |
| Total liabilities | $ | (235.9) |
| Total purchase price allocation, excluding cash and working capital adjustments | $ | 950.0 |

(1) Includes accounts receivables with fair value of $18.9 million, gross contract value of $19.6 million, and $0.7 million of contractual receivables not expected to be collected.

***Impact of Acquisition***

The impact of NMGI and NMGC on the company's revenues in the Consolidated Statements of Operations for the years ended Dec. 31, 2015 and 2014 was an increase of $316.5 million and $137.5 million, respectively. The impact of NMGI and NMGC on the company's net income in the Consolidated Statements of Operations for the years ended Dec. 31, 2015 and 2014 was an increase of $19.6 million and $8.2 million, respectively.

***Pro Forma Impact of the Acquisition***

The following unaudited pro forma financial information reflects the consolidated results of operations of the company and reflects the amortization of purchase accounting adjustments assuming the acquisition had taken place on Jan. 1, 2013. The unaudited pro forma financial information has been presented for illustrative purposes only and is not necessarily indicative of the consolidated results of operations that would have been achieved or the future consolidated results of operations of the company.

Pro forma earnings presented below include adjustments related to non-recurring acquisition consummation, integration and other costs incurred by the company during the period. After-tax non-recurring acquisition consummation, integration and other costs incurred by the company were $8.6 million and $6.2 million for the years ended Dec. 31, 2014 and 2013, respectively.

| **Pro Forma Impact of Acquisition** | *For the year ended Dec. 31,* | |
|---|---|---|
| *(millions, except per share amounts)* | *2014* | *2013* |
| Revenues | $ 2,806.6 | $ 2,704.0 |
| Net income from continuing operations | 223.8 | 216.8 |
| Basic and diluted EPS from continuing operations | 0.96 | 0.93 |

***Transaction and Integration Costs***

The following after-tax transaction and integration charges were recognized in connection with the acquisition and are included in the TECO Energy Consolidated Statement of Income for the years ended Dec. 31, 2015 and 2014.

| **Transaction and Integration Costs** | *For the year ended Dec. 31,* | |
|---|---|---|
| *(millions)* | *2015* | *2014* |
| Legal and other consultants | $ 0.5 | $ 8.0 |
| Bridge loan costs | 0.0 | 3.3 |
| Severance and relocation costs | 1.0 | 2.8 |
| Other costs and tax benefit | 0.4 | (5.5) |
| Total accounting charges | $ 1.9 | $ 8.6 |

The company has an ongoing severance plan under which, in general, the longer a terminated employee worked prior to termination, the greater the amount of severance benefits. The company records a liability and expense for severance once terminations are probable of occurrence and the related severance benefits can be reasonably estimated. For severance benefits that are incremental to its ongoing severance plan ("one-time termination benefits"), the company measures the obligation and records the expense at its fair value at the communication date if there are no future service requirements, or, if future service is required to receive the termination benefit, ratably over the required service period.

In conjunction with the acquisition, in September 2014, TECO Energy and NMGC each offered a severance plan to certain eligible employees. Severance costs incurred were recorded primarily within Operation and maintenance other expense in the Consolidated Condensed Statements of Income. Cash payments under the severance plan began in the third quarter of 2014, and substantially all cash payments under the plan are expected to be made by the end of 2017 resulting in the substantial completion of the acquisition integration plan. As of Dec. 31, 2015 and 2014, the obligations associated with the severance benefits costs were $0.7 million and $2.6 million, respectively.

**22. Quarterly Data (unaudited)**

**Financial data by quarter is as follows:**

*(millions, except per share amounts)*

| *Quarter ended* | *Dec. 31* | *Sept. 30* | *June 30* | *Mar. 31* |
|---|---|---|---|---|
| *2015* | | | | |
| Revenues | $ 676.1 | $ 693.8 | $ 680.6 | $ 693.0 |
| Income from operations | 126.0 | 146.6 | 143.3 | 146.2 |
| Net income from continuing operations | 51.0 | 64.9 | 61.5 | 63.8 |
| Net income | 50.5 | 53.2 | 11.8 | 58.0 |
| EPS—Basic | | | | |
| Net income from continuing operations | $ 0.22 | $ 0.28 | $ 0.26 | $ 0.27 |
| Net income | 0.21 | 0.23 | 0.05 | 0.25 |
| EPS—Diluted | | | | |
| Net income from continuing operations | $ 0.22 | $ 0.28 | $ 0.26 | $ 0.27 |
| Net income | 0.21 | 0.23 | 0.05 | 0.25 |
| Dividends paid per common share outstanding | $ 0.225 | $ 0.225 | $ 0.225 | $ 0.225 |

| *Quarter ended* | *Dec. 31* | *Sept. 30* | *June 30* | *Mar. 31* |
|---|---|---|---|---|
| *2014* | | | | |
| Revenues | $ 695.5 | $ 687.2 | $ 605.7 | $ 578.0 |
| Income from operations | 112.1 | 145.7 | 132.0 | 115.6 |
| Net income from continuing operations | 27.4 | 73.0 | 57.6 | 48.4 |
| Net income | 10.8 | 11.1 | 58.4 | 50.1 |
| EPS—Basic | | | | |
| Net income from continuing operations | $ 0.11 | $ 0.32 | $ 0.27 | $ 0.22 |
| Net income | 0.04 | 0.04 | 0.27 | 0.23 |
| EPS—Diluted | | | | |
| Net income from continuing operations | $ 0.11 | $ 0.32 | $ 0.27 | $ 0.22 |
| Net income | 0.04 | 0.04 | 0.27 | 0.23 |
| Dividends paid per common share outstanding | $ 0.220 | $ 0.220 | $ 0.220 | $ 0.220 |

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

**23. Subsequent Events**

*Amendment of TECO Energy/TECO Finance Credit Facility*

On Feb. 24, 2016, TECO Energy and TECO Finance entered into Amendment No. 3 to its Fourth Amended and Restated Credit Agreement (the TECO Credit Facility) with JPMorgan Chase Bank, N.A., as administrative agent, and certain lenders named therein. The amendment provides that the closing of the Merger will not constitute an event of default under the TECO Credit Facility.

*TECO Energy/TECO Finance One-Year Term Loan Facility*

In February 2016, TECO Energy (as guarantor) and TECO Finance (as borrower) secured commitments for a $400 million one-year term loan facility, the terms of which provide for closing and funding on Mar. 14, 2016. The proceeds of the facility are to be used to repay at maturity the $250 million aggregate principal amount of TECO Finance 4.00% Notes due Mar. 15, 2016, repay a portion of the drawings under the TECO Credit Facility and for general corporate purposes.

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**TAMPA ELECTRIC COMPANY**

**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 index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of Tampa Electric Company and its subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 2 to the financial statements, the Company changed the manner in which it classifies deferred taxes in 2015.

/s/ PricewaterhouseCoopers LLP
Tampa, Florida
February 26, 2016

# TAMPA ELECTRIC COMPANY
## Consolidated Balance Sheets

| *Assets* *(millions)* | *Dec. 31, 2015* | *Dec. 31, 2014* |
|---|---|---|
| **Property, plant and equipment** | | |
| Utility plant in service | | |
| Electric | $ 7,270.3 | $ 7,094.8 |
| Gas | 1,398.6 | 1,308.9 |
| Construction work in progress | 771.1 | 624.2 |
| Utility plant in service, at original costs | 9,440.0 | 9,027.9 |
| Accumulated depreciation | (2,676.8) | (2,633.8) |
| Utility plant in service, net | 6,763.2 | 6,394.1 |
| Other property | 9.7 | 8.6 |
| Total property, plant and equipment, net | 6,772.9 | 6,402.7 |
| | | |
| **Current assets** | | |
| Cash and cash equivalents | 9.1 | 10.4 |
| Receivables, less allowance for uncollectibles of $1.5 and $1.4 at Dec. 31, 2015 and 2014, respectively | 230.2 | 227.2 |
| Inventories, at average cost | | |
| Fuel | 105.6 | 85.2 |
| Materials and supplies | 73.1 | 72.2 |
| Regulatory assets | 44.3 | 52.1 |
| Taxes receivable from affiliate | 61.3 | 43.3 |
| Deferred income taxes | 0.0 | 24.8 |
| Prepayments and other current assets | 21.5 | 17.4 |
| Total current assets | 545.1 | 532.6 |
| | | |
| **Deferred debits** | | |
| Unamortized debt expense | 18.1 | 16.8 |
| Regulatory assets | 373.8 | 319.6 |
| Other | 16.8 | 2.6 |
| Total deferred debits | 408.7 | 339.0 |
| **Total assets** | $ 7,726.7 | $ 7,274.3 |

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, 2015* | *Dec. 31, 2014* |
|---|---|---|
| **Capitalization** | | |
| Common stock | $ 2,305.4 | $ 2,130.4 |
| Accumulated other comprehensive loss | (3.6) | (7.1) |
| Retained earnings | 313.7 | 305.8 |
| Total capital | 2,615.5 | 2,429.1 |
| Long-term debt, less amount due within one year | 2,179.8 | 2,013.8 |
| Total capital | 4,795.3 | 4,442.9 |
| **Current liabilities** | | |
| Long-term debt due within one year | 83.3 | 83.3 |
| Notes payable | 61.0 | 58.0 |
| Accounts payable | 221.6 | 242.3 |
| Customer deposits | 176.3 | 170.4 |
| Regulatory liabilities | 83.2 | 54.7 |
| Derivative liabilities | 24.1 | 36.6 |
| Interest accrued | 16.9 | 17.0 |
| Taxes accrued | 13.2 | 12.4 |
| Other | 10.2 | 10.0 |
| Total current liabilities | 689.8 | 684.7 |
| **Deferred credits** | | |
| Deferred income taxes | 1,308.8 | 1,209.1 |
| Investment tax credits | 10.5 | 9.0 |
| Derivative liabilities | 2.1 | 6.1 |
| Regulatory liabilities | 603.5 | 623.4 |
| Deferred credits and other liabilities | 316.7 | 299.1 |
| Total deferred credits | 2,241.6 | 2,146.7 |
| **Commitments and Contingencies (see Note 9)** | | |
| **Total liabilities and capital** | $ 7,726.7 | $ 7,274.3 |

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,* | *2015* | *2014* | *2013* |
|---|---|---|---|
| **Revenues** | | | |
| Electric | $ 2,017.7 | $ 2,020.5 | $ 1,950.1 |
| Gas | 401.5 | 398.5 | 392.7 |
| Total revenues | 2,419.2 | 2,419.0 | 2,342.8 |
| **Expenses** | | | |
| Regulated operations & maintenance | | | |
| Fuel | 638.6 | 692.3 | 680.2 |
| Purchased power | 78.9 | 71.4 | 64.7 |
| Cost of natural gas sold | 135.5 | 137.0 | 142.6 |
| Other | 528.9 | 518.4 | 523.6 |
| Depreciation and amortization | 313.5 | 302.6 | 290.3 |
| Taxes, other than income | 192.0 | 189.8 | 183.1 |
| Total expenses | 1,887.4 | 1,911.5 | 1,884.5 |
| **Income from operations** | 531.8 | 507.5 | 458.3 |
| **Other income** | | | |
| Allowance for other funds used during construction | 17.2 | 10.5 | 6.3 |
| Other income, net | 2.4 | 4.8 | 5.1 |
| Total other income | 19.6 | 15.3 | 11.4 |
| **Interest charges** | | | |
| Interest expense | 117.9 | 111.7 | 108.9 |
| Allowance for borrowed funds used during construction | (8.3) | (5.1) | (3.6) |
| Total interest charges | 109.6 | 106.6 | 105.3 |
| **Income before provision for income taxes** | 441.8 | 416.2 | 364.4 |
| Provision for income taxes | 165.5 | 155.9 | 138.8 |
| **Net income** | 276.3 | 260.3 | 225.6 |
| **Other comprehensive income, net of tax** | | | |
| Gain on cash flow hedges | 3.5 | 0.7 | 0.9 |
| Total other comprehensive income, net of tax | 3.5 | 0.7 | 0.9 |
| **Comprehensive income** | $ 279.8 | $ 261.0 | $ 226.5 |

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,* | *2015* | *2014* | *2013* |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Net income | $ 276.3 | $ 260.3 | $ 225.6 |
| Adjustments to reconcile net income to net cash from operating activities: | | | |
| Depreciation and amortization | 313.5 | 302.6 | 290.3 |
| Deferred income taxes and investment tax credits | 118.9 | 92.2 | 118.1 |
| Allowance for other funds used during construction | (17.2) | (10.5) | (6.3) |
| Loss on disposal of assets, pretax | 3.1 | 0.0 | 0.0 |
| Deferred recovery clauses | 26.5 | (16.2) | (6.2) |
| Receivables, less allowance for uncollectibles | (3.0) | 0.4 | (13.8) |
| Inventories | (21.3) | 13.1 | (9.0) |
| Prepayments and other deposits | (4.0) | 1.5 | 0.0 |
| Taxes accrued | (17.2) | 11.8 | (34.3) |
| Interest accrued | (0.1) | 0.6 | (0.9) |
| Accounts payable | (26.8) | 5.9 | 34.8 |
| Other | (40.8) | (14.5) | (2.8) |
| Cash flows from operating activities | 607.9 | 647.2 | 595.5 |
| **Cash flows from investing activities** | | | |
| Capital expenditures | (686.6) | (671.0) | (501.3) |
| Net proceeds from sale of assets | 0.0 | 0.0 | 0.1 |
| Cash flows used in investing activities | (686.6) | (671.0) | (501.2) |
| **Cash flows from financing activities** | | | |
| Common stock | 175.0 | 100.0 | 60.0 |
| Proceeds from long-term debt issuance | 251.1 | 296.3 | 0.0 |
| Repayment of long-term debt/Purchase in lieu of redemption | (83.3) | (83.3) | (51.6) |
| Net change in short-term debt | 3.0 | (26.0) | 84.0 |
| Dividends paid | (268.4) | (262.6) | (222.1) |
| Cash flows from/(used in) financing activities | 77.4 | 24.4 | (129.7) |
| **Net increase (decrease) in cash and cash equivalents** | (1.3) | 0.6 | (35.4) |
| **Cash and cash equivalents at beginning of the year** | 10.4 | 9.8 | 45.2 |
| **Cash and cash equivalents at end of the year** | $ 9.1 | $ 10.4 | $ 9.8 |
| | | | |
| **Supplemental disclosure of cash flow information** | | | |
| Cash paid (received) during the year for: | | | |
| Interest | $ 106.2 | $ 102.5 | $ 102.4 |
| Income taxes | $ 63.7 | $ 52.6 | $ 56.4 |
| **Supplemental disclosure of cash flow information** | | | |
| Change in accrued capital expenditures | $ 6.9 | $ 14.3 | $ 4.7 |

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,* | *2015* | *2014* | *2013* |
|---|---|---|---|
| **Balance, beginning of year** | $ 305.8 | $ 308.1 | $ 304.6 |
| Add: Net income | 276.3 | 260.3 | 225.6 |
| | 582.1 | 568.4 | 530.2 |
| Deduct: Cash dividends on capital stock—common | 268.4 | 262.6 | 222.1 |
| **Balance, end of year** | $ 313.7 | $ 305.8 | $ 308.1 |

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

**TAMPA ELECTRIC COMPANY**
**Consolidated Statements of Capitalization**

| | Current | Capital Stock Outstanding Dec. 31, | | Cash Dividends Paid [1] | |
|---|---|---|---|---|---|
| *(millions, except share amounts)* | Redemption Price | Shares | Amount | Per Share | Amount |
| **Common stock - without par value** | | | | | |
| 25 million shares authorized | | | | | |
| 2015 [3] | N/A | 10 | $ 2,305.4 | *(2)* | $ 268.4 |
| 2014 [3] | N/A | 10 | $ 2,130.4 | *(2)* | $ 262.6 |

**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 Mar. 2, May 28, Aug. 28 and Nov. 30 during 2015.
Quarterly dividends paid on Feb. 28, May 28, Aug. 28 and Nov. 28 during 2014.
(2) Not meaningful.
(3) TECO Energy made equity contributions to TEC of $175.0 million in 2015 and $100.0 million in 2014.

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

**TAMPA ELECTRIC COMPANY**
**Consolidated Statements of Capitalization** – continued

At Dec. 31, 2015 and 2014, TEC had the following long-term debt outstanding:

**Long-Term Debt**

| *(millions)* | | *Due* | *2015* | *2014* |
|---|---|---|---|---|
| **Tampa Electric** | Installment contracts payable [1] : | | | |
| | 5.65% Refunding bonds | 2018 | $ 54.2 | $ 54.2 |
| | Variable rate bonds repurchased in 2008 [2] | 2020 | 0.0 | 0.0 |
| | 5.15% Refunding bonds repurchased in 2013 [3] | 2025 | 0.0 | 0.0 |
| | 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][7] : 6.25% | 2015-2016 | 83.3 | 166.7 |
| | 6.10% | 2018 | 200.0 | 200.0 |
| | 5.40% | 2021 | 231.7 | 231.7 |
| | 2.60% | 2022 | 225.0 | 225.0 |
| | 6.55% | 2036 | 250.0 | 250.0 |
| | 6.15% | 2037 | 190.0 | 190.0 |
| | 4.10% | 2042 | 250.0 | 250.0 |
| | 4.35% | 2044 | 290.0 | 290.0 |
| | 4.20% | 2045 | 230.0 | 0.0 |
| | Total long-term debt of Tampa Electric | | 2,004.2 | 1,857.6 |
| **PGS** | Notes [6][7] : 6.10% | 2018 | 50.0 | 50.0 |
| | 5.40% | 2021 | 46.7 | 46.7 |
| | 2.60% | 2022 | 25.0 | 25.0 |
| | 6.15% | 2037 | 60.0 | 60.0 |
| | 4.10% | 2042 | 50.0 | 50.0 |
| | 4.35% | 2044 | 10.0 | 10.0 |
| | 4.20% | 2045 | 20.0 | 0.0 |
| | Total long-term debt of PGS | | 261.7 | 241.7 |
| Total long-term debt of TEC | | | 2,265.9 | 2,099.3 |
| Unamortized debt discount, net | | | (2.8) | (2.2) |
| Total carrying amount of long-term debt | | | 2,263.1 | 2,097.1 |
| Less amount due within one year | | | 83.3 | 83.3 |
| Total long-term debt | | | $ 2,179.8 | $ 2,013.8 |

(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 issuer.
(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, 2015, total long-term debt had a carrying amount of $2,263.1 million and an estimated fair market value of $2,433.3 million. At Dec. 31, 2014, total long-term debt had a carrying amount of $2,097.1 million and an estimated fair market value of $2,372.2 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 2016 through 2020 and thereafter are as follows:

**Long-Term Debt Maturities**

| *As of Dec. 31, 2015 (millions)* | *2016* | *2017* | *2018* | *2019* | *2020* | *Thereafter* | *Total Long-Term Debt* |
|---|---|---|---|---|---|---|---|
| Tampa Electric | $ 83.3 | $ 0.0 | 254.2 | $ 0.0 | $ 0.0 | $ 1,666.7 | $ 2,004.2 |
| PGS | 0.0 | 0.0 | 50.0 | 0.0 | 0.0 | 211.7 | 261.7 |
| Total long-term debt maturities | $ 83.3 | $ 0.0 | $ 304.2 | $ 0.0 | $ 0.0 | $ 1,878.4 | $ 2,265.9 |

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

# TAMPA ELECTRIC COMPANY
# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

## 1. Significant Accounting Policies

TEC has two business segments. Its Tampa Electric division provides retail electric services in West Central Florida, and 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. TEC's 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 U.S. 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 (see **Note 3** for additional details).

TEC's retail and wholesale businesses are regulated by the FPSC and 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. 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 U.S. 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 noncontrolling 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**).

On Sept. 4, 2015, TECO Energy and Emera entered into the Merger Agreement. Upon closing, TECO Energy will become a wholly owned subsidiary of Emera. See **Note 16** for further information.

### 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.

### Property, Plant and Equipment

Property, plant and equipment is stated at original cost, which includes labor, material, applicable taxes, overhead and AFUDC. Concurrent with a planned major maintenance outage or with new construction, the cost of adding or replacing retirement units-of-property is capitalized in conformity with the regulations of FERC and FPSC. The cost of maintenance, repairs and replacement of minor items of property is expensed as incurred.

In general, when regulated depreciable property is retired or disposed, its original cost less salvage is charged to accumulated depreciation. For other property dispositions, the cost and accumulated depreciation are removed from the balance sheet and a gain or loss is recognized.

**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 2015, 2014 and 2013. 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, 2015, 2014 and 2013 was $306.0 million, $295.8 million and $284.2 million, respectively.

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

**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. In March 2014, the rate was revised to 6.46% effective Jan. 1, 2014. Total AFUDC for the years ended Dec. 31, 2015, 2014 and 2013 was $25.5 million, $15.6 million and $9.9 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.

**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.

**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 for a closer matching of revenues and expenses (see **Note 3**). As of Dec. 31, 2015 and 2014, unbilled revenues of $53.7 million and $49.3 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 $78.9 million, $71.4 million and $64.7 million, for the years ended Dec. 31, 2015, 2014 and 2013, respectively. The prudently incurred purchased power costs at Tampa Electric have historically been recovered through an FPSC-approved cost-recovery clause.

**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 TEC’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.

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

TEC is allowed to recover certain costs on a dollar-for-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 $116.9 million, $113.9 million and $108.5 million for the years ended Dec. 31, 2015, 2014 and 2013, respectively. Excise taxes paid by the regulated utilities are not material and are expensed as incurred.

**Deferred Credits and Other Liabilities**

Other deferred credits primarily include the accrued postretirement and pension liabilities (see **Note 5**), MGP environmental remediation liability (see **Note 9**), and medical and general liability claims incurred but not reported. TECO Energy and its subsidiaries, including TEC, have a self-insurance program supplemented by excess insurance coverage for the cost of claims whose ultimate value exceeds the company’s retention amounts. TEC 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, 2015 and 2014 ranged from 2.92% to 4.00% and 2.71% to 4.00%, respectively.

**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. 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.

**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**

**Revenue from Contracts with Customers**

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The standard is principle-based and provides a five-step model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In addition, the guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. This guidance will be effective for TEC beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. TEC expects to adopt this guidance effective Jan. 1, 2018, and is continuing to evaluate the available adoption methods and the impact of the adoption of this guidance on its financial statements, but does not expect the impact to be significant.

**Presentation of Debt Issuance Costs**

In April 2015, the FASB issued guidance regarding the presentation of debt issuance costs on the balance sheet. Under the new guidance, an entity is required to present debt issuance costs as a direct deduction from the carrying amount of the related debt liability rather than as a deferred charge (i.e., as an asset) under current guidance. In August 2015, the FASB amended the guidance to include an SEC staff announcement that it will not object to a company presenting debt issuance costs related to line-of-credit arrangements as an asset, regardless of whether a balance is outstanding. This guidance will be effective for TEC beginning in 2016 and will be required to be applied on a retrospective basis for all periods presented. As of Dec. 31, 2015, $18.1 million of debt issuance costs, which does not include costs for line-of-credit arrangements, are included in “Deferred debits” on TEC’s Consolidated Condensed Balance Sheet. The guidance will not affect TEC’s results of operations or cash flows.

**Disclosure of Investments Using Net Asset Value**

In May 2015, the FASB issued guidance stating that investments for which fair value is measured using the NAV per share practical expedient should not be categorized in the fair value hierarchy but should be provided to reconcile to total investments on the balance sheet. In addition, the guidance clarifies that a plan sponsor’s pension assets are eligible to be measured at NAV as a practical expedient and that those investments should also not be categorized in the fair value hierarchy. TECO Energy’s pension plan, in which TEC participates, has such investments as disclosed in **Note 5**. This standard will be required for TEC beginning in 2016. As early adoption is permitted, TEC adopted the standard for its 2015 fiscal year and applied the presentation on a retrospective basis for all periods presented in the pension plan assets fair value hierarchy. The guidance did not affect TEC’s balance sheets, results of operations or cash flows.

**Measurement Period Adjustments in Business Combinations**

In September 2015, the FASB issued guidance requiring an acquirer in a business combination to account for measurement period adjustments during the reporting period in which the adjustment is determined, rather than retrospectively. When measurements are incomplete as of the end of the reporting period covering a business combination, an acquirer may record adjustments to provisional amounts based on events and circumstances that existed as of the acquisition date during the period from the date of acquisition to the date information is received, not to exceed one year. The guidance will be effective for TEC beginning in 2016 and will be applied prospectively. The guidance will not affect TEC’s current financial statements. However, TEC will assess the potential impact of the guidance on future acquisitions.

**Balance Sheet Classification of Deferred Taxes**

In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. To simplify the presentation of deferred income taxes, the new guidance requires that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet rather than be classified as current or noncurrent under current guidance. The guidance will be required for TEC beginning in 2017 and may be applied on a prospective or retrospective basis. As early adoption is permitted, TEC adopted the standard in December 2015 and applied the balance sheet presentation on a prospective basis. Therefore, prior period balance sheets were not retrospectively adjusted. The guidance did not affect TEC’s results of operations or cash flows.

**Recognition and Measurement of Financial Assets and Financial Liabilities**

In January 2016, the FASB issued guidance related to accounting for financial instruments, including equity investments, financial liabilities under the fair value option, valuation allowances for available-for-sale debt securities, and the presentation and disclosure requirements for financial instruments. TEC does not have equity investments or available-for-sale debt securities and it does not record financial liabilities under the fair value option. However, it is evaluating the impact of the adoption of this guidance on its financial statement disclosures, including those regarding the fair value of its long-term debt, but it does not expect the impact to be significant. The guidance will be effective for TEC beginning in 2018.

**Leases**

In February 2016, the FASB issued guidance regarding the accounting for leases. The objective is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with a lease term of more than 12 months. In addition, the guidance will require additional disclosures regarding key information about leasing arrangements. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. The dual model for income statement classification is maintained under the new guidance and as a result is expected to limit the impact of the changes on the income statement and statement of cash flows. This guidance will be effective for TEC beginning in 2019, with early adoption permitted, and will be applied using a modified retrospective approach. TEC is currently evaluating the impacts of the adoption of the guidance on its financial statements.

**3. Regulatory**

Tampa Electric’s retail business and PGS are regulated by the FPSC. Tampa Electric is also subject to regulation by the FERC. 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 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.

Tampa Electric’s results for 2015, 2014 and the last two months of 2013 reflect the results of a Stipulation and Settlement Agreement entered on Sept. 6, 2013, between Tampa Electric and all of the intervenors in its Tampa Electric division base rate proceeding, which resolved all matters in Tampa Electric’s 2013 base rate proceeding. On Sept. 11, 2013, the FPSC unanimously voted to approve the stipulation and settlement agreement.

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 Tampa Electric’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 no sooner than Jan. 1, 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 Tampa Electric could seek a review of its base rates. Under the agreement, the allowed equity in the capital structure is 54% from investor sources of capital and Tampa Electric began using a 15-year amortization period for all computer software retroactive to Jan. 1, 2013.

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 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. Effective Nov. 1, 2013, Tampa Electric ceased accruing for this storm damage reserve as a result of the 2013 rate case settlement. 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 $56.1 million; the level it was as of Oct. 31, 2013. Tampa Electric’s storm reserve remained $56.1 million at both Dec. 31, 2015 and 2014.

**Base Rates-PGS**

PGS’s base rates were established in May 2009 and reflect an ROE of 10.75%, which is the middle of a range between 9.75% to 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.

**Regulatory Assets and Liabilities**

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; 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; and the advance recovery of expenditures for approved costs such as future storm damage or the future removal of property. All regulatory assets are recovered through the regulatory process.

Details of the regulatory assets and liabilities as of Dec. 31, 2015 and 2014 are presented in the following table:

**Regulatory Assets and Liabilities**

| *(millions)* | *Dec. 31, 2015* | *Dec. 31, 2014* |
|---|---|---|
| **Regulatory assets:** | | |
| Regulatory tax asset [1] | $ 74.6 | $ 69.2 |
| Cost-recovery clauses - deferred balances [2] | 5.2 | 0.9 |
| Cost-recovery clauses - offsets to derivative liabilities [2] | 26.2 | 42.7 |
| Environmental remediation [3] | 54.0 | 53.1 |
| Postretirement benefits [4] | 238.3 | 187.8 |
| Deferred bond refinancing costs [5] | 6.5 | 7.2 |
| Competitive rate adjustment [2] | 2.6 | 2.8 |
| Other | 10.7 | 8.0 |
| Total regulatory assets | 418.1 | 371.7 |
| Less: Current portion | 44.3 | 52.1 |
| Long-term regulatory assets | $ 373.8 | $ 319.6 |
| **Regulatory liabilities:** | | |
| Regulatory tax liability | $ 5.7 | $ 5.1 |
| Cost-recovery clauses [2] | 54.2 | 23.5 |
| Transmission and delivery storm reserve | 56.1 | 56.1 |
| Accumulated reserve—cost of removal [6] | 570.0 | 591.5 |
| Other | 0.7 | 1.9 |
| Total regulatory liabilities | 686.7 | 678.1 |
| Less: Current portion | 83.2 | 54.7 |
| Long-term regulatory liabilities | $ 603.5 | $ 623.4 |

(1) The regulatory tax asset is primarily associated with the depreciation and recovery of AFUDC-equity. This asset does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be recovered over the expected life of the related assets.

(2) These assets and liabilities are related to FPSC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC on a dollar-for-dollar basis in the next year. In the case of the regulatory asset related to derivative liabilities, recovery occurs in the year following the settlement of the derivative position.

(3) This asset is related to costs associated with environmental remediation primarily at manufactured gas plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is impacted by the timing of the expenditures related to remediation.

(4) This asset is related to the deferred costs of postretirement benefits. It is included in rate base and earns a rate of return as permitted by the FPSC. It is amortized over the remaining service life of plan participants.

(5) This asset represents the past costs associated with refinancing debt. It does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be amortized over the term of the related debt instruments.

(6) This item represents the non-ARO cost of removal in the accumulated reserve for depreciation.

## 4. Income Taxes

### Income Tax Expense

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.

Income tax expense consists of the following components:

**Income Tax Expense (Benefit)**

| *(millions)* *For the year ending Dec. 31,* | 2015 | 2014 | 2013 |
|---|---|---|---|
| Current income taxes | | | |
| Federal | $ 38.2 | $ 54.8 | $ 19.4 |
| State | 8.4 | 8.9 | 1.3 |
| Deferred income taxes | | | |
| Federal | 102.9 | 79.0 | 99.8 |
| State | 14.5 | 13.5 | 18.6 |
| Amortization of investment tax credits | 1.5 | (0.3) | (0.3) |
| Total income tax expense | $ 165.5 | $ 155.9 | $ 138.8 |

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,* | 2015 | 2014 | 2013 |
|---|---|---|---|
| Income tax expense at the federal statutory rate of 35% | $ 154.6 | $ 145.7 | $ 127.5 |
| Increase (decrease) due to | | | |
| State income tax, net of federal income tax | 14.8 | 14.5 | 13.0 |
| Other | (3.9) | (4.3) | (1.7) |
| Total income tax expense on consolidated statements of income | $ 165.5 | $ 155.9 | $ 138.8 |
| Income tax expense as a percent of income from continuing operations, before income taxes | 37.5% | 37.5% | 38.1% |

**Deferred Income Taxes**

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:

| *(millions)* *As of Dec. 31,* | 2015 | 2014 |
|---|---|---|
| Deferred tax liabilities (1) | | |
| Property related | $ 1,431.9 | $ 1,328.8 |
| Pension and postretirement benefits | 92.0 | 72.5 |
| Pension | 71.1 | 51.8 |
| Total deferred tax liabilities | 1,595.0 | 1,453.1 |
| Deferred tax assets (1) | | |
| Loss and credit carryforwards | 80.0 | 77.7 |
| Medical benefits | 47.7 | 51.0 |
| Insurance reserves | 27.6 | 29.0 |
| Pension and postretirement benefits | 92.0 | 72.5 |
| Capitalized energy conservation assistance costs | 21.4 | 20.3 |
| Other | 17.5 | 18.3 |
| Total deferred tax assets | 286.2 | 268.8 |
| Total deferred tax liability, net | 1,308.8 | 1,184.3 |
| Less: Current portion of deferred tax asset | 0.0 | (24.8) |
| Long-term portion of deferred tax liability, net | $ 1,308.8 | $ 1,209.1 |

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

At Dec. 31, 2015, TEC had cumulative unused federal and Florida NOLs for income tax purposes of $194.1 million and $268.5 million, respectively, expiring in 2033. In addition, TEC has unused general business credits of $1.9 million, expiring between 2028 and 2035.

**Unrecognized Tax Benefits**

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, 2015 and 2014, TEC does not have a liability for unrecognized tax benefits. Based on current information, TEC does not anticipate that this will change materially in 2016. As of Dec. 31, 2015 and 2014, TEC does not have a liability recorded for payment of interest and penalties associated with uncertain tax positions.

The IRS concluded its examination of TECO Energy’s 2014 consolidated federal income tax return in December 2015. The U.S. federal statute of limitations remains open for the year 2012 and onward. Years 2015 and 2016 are currently under examination by the IRS under its Compliance Assurance Program. 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 2005 and forward as a result of TECO Energy’s consolidated Florida net operating loss still being utilized. 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 qualified, 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.

Amounts disclosed for pension benefits in the following tables and discussion also include the fully-funded 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 (Other Benefits) for most 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 2013. TEC is amortizing the regulatory asset over the remaining average service life at the time 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 implemented 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, which are greater than the subsidy payments previously received by the company 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.

The following table provides a detail of the change in TECO Energy's benefit obligations and change in plan assets for combined pension plans (pension benefits) and combined other postretirement benefit plans (other benefits).

| **TECO Energy** **Obligations and Funded Status** *(millions)* | **Pension Benefits** | | **Other Benefits** | |
|---|---|---|---|---|
| | *2015* | *2014* | *2015* | *2014* |
| **Change in benefit obligation** | | | | |
| Net benefit obligation at beginning of year | $ 728.9 | $ 666.0 | $ 201.5 | $ 208.1 |
| Service cost | 20.9 | 18.3 | 2.2 | 2.5 |
| Interest cost | 30.3 | 32.0 | 8.2 | 10.8 |
| Plan participants' contributions | 0.0 | 0.0 | 2.0 | 2.8 |
| Plan amendments | 0.0 | 0.0 | (3.7) | (23.2) |
| Actuarial loss (gain) | 5.8 | 48.3 | (0.4) | 1.5 |
| Benefits paid | (53.0) | (39.9) | (14.6) | (16.0) |
| Transfer in due to the effect of business combination | 0.0 | 0.0 | 0.0 | 26.7 |
| Plan curtailment | 0.0 | 4.0 | 0.0 | (11.7) |
| Special termination benefit | 0.0 | 0.2 | 0.0 | 0.0 |
| Net benefit obligation at end of year | $ 732.9 | $ 728.9 | $ 195.2 | $ 201.5 |
| | | | | |
| **Change in plan assets** | | | | |
| Fair value of plan assets at beginning of year | $ 648.0 | $ 593.0 | $ 18.8 | $ 0.0 |
| Actual return on plan assets | (25.5) | 46.4 | (0.6) | 0.1 |
| Employer contributions | 55.0 | 47.5 | 1.5 | (1.0) |
| Employer direct benefit payments | 0.9 | 1.0 | 13.5 | 16.0 |
| Plan participants' contributions | 0.0 | 0.0 | 2.0 | 2.8 |
| Transfer in due to acquisition | 0.0 | 0.0 | 0.0 | 16.9 |
| Benefits paid | (53.0) | (39.9) | (14.6) | (16.0) |
| Fair value of plan assets at end of year (1) | $ 625.4 | $ 648.0 | $ 20.6 | 18.8 |

(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.

At Dec. 31, the aggregate financial position for TECO Energy pension plans and other postretirement plans with benefit obligations in excess of plan assets was as follows:

| **Funded Status** | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(millions)* | *2015* | *2014* | *2015* | *2014* |
| Benefit obligation (PBO/APBO) | $ 732.9 | $ 728.9 | $ 195.2 | $ 201.5 |
| Less: Fair value of plan assets | 625.4 | 648.0 | 20.6 | 18.8 |
| Funded status at end of year | $ (107.5) | $ (80.9) | $ (174.6) | $ (182.7) |

The accumulated benefit obligation for TECO Energy consolidated defined benefit pension plans was $686.9 million at Dec. 31, 2015 and $685.0 million at Dec. 31, 2014.

The amounts recognized in TEC's Consolidated Balance Sheets for pension and other postretirement benefit obligations, plan assets, and unrecognized costs at Dec. 31 were as follows:

| **Tampa Electric Company**<br>**Amounts recognized in balance sheet** | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(millions)* | *2015* | *2014* | *2015* | *2014* |
| Regulatory assets | $ 208.2 | $ 167.4 | $ 30.2 | $ 20.4 |
| Accrued benefit costs and other current liabilities | (0.6) | (0.6) | (9.2) | (9.1) |
| Deferred credits and other liabilities | (69.3) | (53.5) | (142.3) | (137.1) |
| | $ 138.3 | $ 113.3 | $ (121.3) | $ (125.8) |

Unrecognized gains and losses and prior service credits and costs are recorded in regulatory assets for TEC. The following table provides a detail of the unrecognized gains and losses and prior service credits and costs.

| **Amounts recognized in regulatory assets** | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| *(millions)* | *2015* | *2014* | *2015* | *2014* |
| Net actuarial loss (gain) | $ 208.2 | $ 167.7 | $ 47.2 | $ 39.5 |
| Prior service cost (credit) | 0.0 | (0.3) | (17.0) | (19.1) |
| Amount recognized | $ 208.2 | $ 167.4 | $ 30.2 | $ 20.4 |

**Assumptions used to determine benefit obligations at Dec. 31:**

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | *2015* | *2014* | *2015* | *2014* |
| Discount rate | 4.688% | 4.258% | 4.669% | 4.211% |
| Rate of compensation increase-weighted average | 3.87% | 3.87% | 2.50% | 3.86% |
| Healthcare cost trend rate | | | | |
| Immediate rate | n/a | n/a | 7.05% | 7.09% |
| Ultimate rate | n/a | n/a | 4.50% | 4.57% |
| Year rate reaches ultimate | n/a | n/a | 2038 | 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 | $ 6.1 | $ (5.2) |

The discount rate assumption used to determine the Dec. 31, 2015 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.

**Amounts recognized in Net Periodic Benefit Cost, OCI, and Regulatory Assets**

| TECO Energy | Pension Benefits | | | Other Benefits | | |
|---|---|---|---|---|---|---|
| | *2015* | *2014* | *2013* | *2015* | *2014* | *2013* |
| *(millions)* | | | | | | |
| Service cost | $ 20.9 | $ 18.3 | $ 18.2 | $ 2.2 | $ 2.5 | $ 2.5 |
| Interest cost | 30.3 | 32.0 | 28.9 | 8.2 | 10.8 | 9.3 |
| Expected return on plan assets | (43.3) | (41.8) | (38.4) | (1.1) | (0.3) | 0.0 |
| Amortization of: | | | | | | |
| Actuarial loss | 15.1 | 13.5 | 20.5 | 0.0 | 0.2 | 1.0 |
| Prior service (benefit) cost | (0.2) | (0.4) | (0.4) | (2.4) | (0.2) | (0.4) |
| Curtailment loss (gain) | 0.0 | 3.9 | 0.0 | 0.0 | (0.2) | 0.0 |
| Special termination benefit | 0.0 | 0.2 | 0.0 | 0.0 | 0.0 | 0.0 |
| Settlement loss | 0.0 | 0.0 | 1.0 | 0.0 | 0.0 | 0.0 |
| Net periodic benefit cost | $ 22.8 | $ 25.7 | $ 29.8 | $ 6.9 | $ 12.8 | $ 12.4 |
| | | | | | | |
| New prior service cost | $ 0.0 | $ 0.0 | $ 0.0 | $ (3.7) | $ (23.6) | $ 0.0 |
| Net loss (gain) arising during the year | 74.5 | 44.1 | (75.7) | 1.3 | (9.9) | (15.6) |
| Unrecognized costs in regulated asset acquired in business combination | 0.0 | 0.0 | 0.0 | 0.0 | 6.4 | 0.0 |
| Amounts recognized as component of net periodic benefit cost: | | | | | | |
| Amortization of actuarial gain (loss) | (15.1) | (13.5) | (21.5) | 0.0 | (0.2) | (1.0) |
| Amortization of prior service (benefit) cost | 0.2 | 0.4 | 0.4 | 2.4 | 0.2 | 0.3 |
| Total recognized in OCI and regulatory assets | $ 59.6 | $ 31.0 | $ (96.8) | $ 0.0 | $ (27.1) | $ (16.3) |
| **Total recognized in net periodic benefit cost, OCI and regulatory assets** | $ 82.4 | $ 56.7 | $ (67.0) | $ 6.9 | $ (14.3) | $ (3.9) |

TEC's portion of the net periodic benefit costs for pension benefits was $13.5 million, $14.8 million and $21.7 million for 2015, 2014 and 2013, respectively. TEC's portion of the net periodic benefit costs for other benefits was $5.7 million, $10.4 million and $10.0 million for 2015, 2014 and 2013, respectively.

The estimated net loss 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 $9.8 million. There will be an estimated $1.9 million prior service credit that will be amortized from regulatory assets into net periodic benefit cost over the next fiscal year for the other postretirement benefit plan.

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

| | Pension Benefits | | | Other Benefits | | |
|---|---|---|---|---|---|---|
| | *2015* | *2014* [(1)] | *2013* | *2015* | *2014* | *2013* |
| Discount rate | 4.258% | 5.118%/4.277%/4.331% | 4.196% | 4.211% | 5.096% | 4.180% |
| Expected long-term return on plan assets | 7.00% | 7.25%/7.00%/7.00% | 7.50% | 5.75 | 5.75 | n/a |
| Rate of compensation increase | 3.87% | 3.73% | 3.76% | 3.86% | 3.71% | 3.74% |
| Healthcare cost trend rate | | | | | | |
| Initial rate | n/a | n/a | n/a | 7.09% | 7.25% | 7.50% |
| Ultimate rate | n/a | n/a | n/a | 4.57% | 4.50% | 4.50% |
| Year rate reaches ultimate | n/a | n/a | n/a | 2025 | 2025 | 2025 |

(1) TECO Energy performed a valuation as of Jan. 1, 2014. TECO remeasured its Retirement Plan on Sept. 2, 2014 for the acquisition of NMGC and on Oct. 31, 2014 for the expected curtailment of TECO Coal, resulting in the respective updated discount rates and EROAs.

The discount rate assumption used to determine the 2015 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, 2015, TECO Energy's pension plan's assets decreased approximately 3.5%.

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** | | *2015* | *2014* |
| Equity securities | 47%-53% | 53% | 50% |
| Fixed income securities | 47%-53% | 47% | 50% |
| 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). Investments are valued using quoted market prices on an exchange when available. Such investments are classified Level 1. In some cases where a market exchange price is available but the investments are traded in a secondary market, acceptable practical expedients are used to calculate fair value.

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, 2015 and 2014.

**Pension Plan Investments**

| *(millions)* | At Fair Value as of Dec. 31, 2015 | | | | |
|---|---|---|---|---|---|
| | **Level 1** | **Level 2** | **Level 3** | **Using NAV (1)** | **Total** |
| Net cash | | | | | |
| Cash | $ 1.9 | $ 0.0 | $ 0.0 | $ 0.0 | $ 1.9 |
| Accounts receivable | 14.3 | 0.0 | 0.0 | 0.0 | 14.3 |
| Accounts payable | (27.2) | 0.0 | 0.0 | 0.0 | (27.2) |
| Total net cash | (11.0) | 0.0 | 0.0 | 0.0 | (11.0) |
| Cash equivalents | | | | | |
| Money markets | 0.0 | 0.2 | 0.0 | 0.0 | 0.2 |
| Discounted notes | 0.0 | 0.7 | 0.0 | 0.0 | 0.7 |
| Short-term investment funds (STIFs) (1) | 0.0 | 0.0 | 0.0 | 12.4 | 12.4 |
| Total cash equivalents | 0.0 | 0.9 | 0.0 | 12.4 | 13.3 |
| Equity securities | | | | | |
| Common stocks | 90.9 | 0.0 | 0.0 | 0.0 | 90.9 |
| American depository receipts (ADRs) | 5.7 | 0.0 | 0.0 | 0.0 | 5.7 |
| Real estate investment trusts (REITs) | 4.8 | 0.0 | 0.0 | 0.0 | 4.8 |
| Commingled fund | 0.0 | 53.7 | 0.0 | 0.0 | 53.7 |
| Mutual funds (1) | 0.0 | 0.0 | 0.0 | 175.6 | 175.6 |
| Total equity securities | 101.4 | 53.7 | 0.0 | 175.6 | 330.7 |
| Fixed income securities | | | | | |
| Municipal bonds | 0.0 | 5.0 | 0.0 | 0.0 | 5.0 |
| Government bonds | 0.0 | 56.2 | 0.0 | 0.0 | 56.2 |
| Corporate bonds | 0.0 | 32.2 | 0.0 | 0.0 | 32.2 |
| Asset backed securities (ABS) | 0.0 | 0.3 | 0.0 | 0.0 | 0.3 |
| Mortgage-backed securities (MBS), net short sales | 0.0 | 8.7 | 0.0 | 0.0 | 8.7 |
| Collateralized mortgage obligations (CMOs) | 0.0 | 1.5 | 0.0 | 0.0 | 1.5 |
| Commingled fund (1) | 0.0 | 0.0 | 0.0 | 117.9 | 117.9 |
| Mutual fund (1) | 0.0 | 0.0 | 0.0 | 71.3 | 71.3 |
| Total fixed income securities | 0.0 | 103.9 | 0.0 | 189.2 | 293.1 |
| Derivatives | | | | | |
| Swaps | 0.0 | (0.9) | 0.0 | 0.0 | (0.9) |
| Purchased options (swaptions) | 0.0 | 1.1 | 0.0 | 0.0 | 1.1 |
| Written options (swaptions) | 0.0 | (1.0) | 0.0 | 0.0 | (1.0) |
| Total derivatives | 0.0 | (0.8) | 0.0 | 0.0 | (0.8) |
| Miscellaneous | 0.0 | 0.1 | 0.0 | 0.0 | 0.1 |
| Total | $ 90.4 | $ 157.8 | $ 0.0 | $ 377.2 | $ 625.4 |

(1) In accordance with accounting standards, certain investments that are measured at fair value using the net asset value per share practical expedient have not been classified in the fair value hierarchy. The fair value amounts in this table are to permit reconciliation of the fair value hierarchy to amounts presented in the Consolidated Balance Sheet.

| *(millions)* | At Fair Value as of Dec. 31, 2014 | | | | |
|---|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Using NAV [1] | Total |
| Net cash | | | | | |
| Cash | $ 0.4 | $ 0.0 | $ 0.0 | $ 0.0 | $ 0.4 |
| Accounts receivable | 1.4 | 0.0 | 0.0 | 0.0 | 1.4 |
| Accounts payable | (5.3) | 0.0 | 0.0 | 0.0 | (5.3) |
| Total net cash | (3.5) | 0.0 | 0.0 | 0.0 | (3.5) |
| Cash equivalents | | | | | |
| Treasury bills (T bills) | 0.0 | 0.2 | 0.0 | 0.0 | 0.2 |
| Discounted notes | 0.0 | 8.8 | 0.0 | 0.0 | 8.8 |
| Short-term investment funds (STIFs) [1] | 0.0 | 0.0 | 0.0 | 7.6 | 7.6 |
| Total cash equivalents | 0.0 | 9.0 | 0.0 | 7.6 | 16.6 |
| Equity securities | | | | | |
| Common stocks | 98.0 | 0.0 | 0.0 | 0.0 | 98.0 |
| American depository receipts (ADRs) | 1.3 | 0.0 | 0.0 | 0.0 | 1.3 |
| Real estate investment trusts (REITs) | 2.5 | 0.0 | 0.0 | 0.0 | 2.5 |
| Preferred stock | 0.8 | 0.0 | 0.0 | 0.0 | 0.8 |
| Commingled fund | 0.0 | 45.6 | 0.0 | 0.0 | 45.6 |
| Mutual funds [1] | 0.0 | 0.0 | 0.0 | 171.3 | 171.3 |
| Total equity securities | 102.6 | 45.6 | 0.0 | 171.3 | 319.5 |
| Fixed income securities | | | | | |
| Municipal bonds | 0.0 | 6.1 | 0.0 | 0.0 | 6.1 |
| Government bonds | 0.0 | 47.9 | 0.0 | 0.0 | 47.9 |
| Corporate bonds | 0.0 | 22.0 | 0.0 | 0.0 | 22.0 |
| Asset backed securities (ABS) | 0.0 | 0.3 | 0.0 | 0.0 | 0.3 |
| Mortgage-backed securities (MBS), net short sales | 0.0 | 9.6 | 0.0 | 0.0 | 9.6 |
| Collateralized mortgage obligations (CMOs) | 0.0 | 2.0 | 0.0 | 0.0 | 2.0 |
| Commingled fund [1] | 0.0 | 0.0 | 0.0 | 129.20 | 129.2 |
| Mutual fund [1] | 0.0 | 0.0 | 0.0 | 98.6 | 98.6 |
| Total fixed income securities | 0.0 | 87.9 | 0.0 | 227.8 | 315.7 |
| Derivatives | | | | | |
| Short futures | 0.0 | (0.3) | 0.0 | 0.0 | (0.3) |
| Purchased options (swaptions) | 0.0 | 0.7 | 0.0 | 0.0 | 0.7 |
| Written options (swaptions) | 0.0 | (0.8) | 0.0 | 0.0 | (0.8) |
| Total derivatives | 0.0 | (0.4) | 0.0 | 0.0 | (0.4) |
| Miscellaneous | 0.0 | 0.1 | 0.0 | 0.0 | 0.1 |
| Total | $ 99.1 | $ 142.2 | $ 0.0 | $ 406.7 | $ 648.0 |

(1) In accordance with accounting standards, certain investments that are measured at fair value using the net asset value per share practical expedient have not been classified in the fair value hierarchy. The fair value amounts in this table are to permit reconciliation of the fair value hierarchy to amounts presented in the Consolidated Balance Sheet.

The following list details the pricing inputs and methodologies used to value the investments in the pension plan:

- The primary pricing inputs in determining the fair value of the Level 1 assets are closing quoted prices in active markets.
- The methodology and inputs used to value the investment in the equity commingled fund are broker dealer quotes sourced by State Street Custody System. The fund holds primarily international equity securities that are actively traded in over-the-counter markets. The fund honors subscription and redemption activity on an “as of” basis.
- The money markets are valued at cost due to their short-term nature. Discounted notes are valued at amortized cost.
- 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 CMO 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.

- 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.
- The STIF is valued at NAV as determined by JP Morgan. The funds are open-end investments. Additionally, 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.
- The primary pricing inputs in determining the equity 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.
- The primary pricing input in determining the fair value of the fixed asset mutual fund is its NAV. It is an unregistered open-ended mutual fund.
- The fixed income commingled fund is a private fund valued at NAV. 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.

Additionally, the unqualified SERP had $43.5 million and $0.9 million of assets as of Dec. 31, 2015 and 2014, respectively. Since the plan is unqualified, its assets are included in the "Deferred charges and other assets" line item in TECO Energy's Consolidated Balance Sheets rather than being netted with the related liability. The fund holds investments in a money market fund, which is valued at cost due to its short-term nature, making this a level 2 asset. The SERP was fully funded as of Dec. 31, 2015.

**Other Postretirement Benefit Plan Assets**

There are no assets associated with TECO Energy's other postretirement benefits plan. Asset amounts shown in the tables above relate to a separate NMGC other postretirement benefit plan.

**Contributions**

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 2013, 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 August 2014, the President signed into law HAFTA, which modified MAP-21. HAFTA and MAP-21 provide 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 HAFTA and MAP-21. In November 2015, the President signed into law the Bipartisan Budget Act of 2015, which extended pension funding relief of MAP-21 and HAFTA through 2022.

The qualified pension plan's actuarial value of assets, including credit balance, was 120.1% of the Pension Protection Act funded target as of Jan. 1, 2015 and is estimated at 114.1% of the Pension Protection Act funded target as of Jan. 1, 2016.

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 $55.0 million of contributions to this plan in 2015 and $47.5 million in 2014, which met the minimum funding requirements for both 2015 and 2014. TEC's portion of the contribution in 2015 was $43.9 million and in 2014 was $38.2 million. These amounts are reflected in the "Other" line on the Consolidated Statements of Cash Flows. TECO Energy estimates its contribution in 2016 to be $37.4 million, with TEC's portion being $30.9 million. TECO Energy estimates it will make annual contributions from 2017 to 2020 ranging from $12.2 to $44.6 million per year based on current assumptions, with TEC's portion to range from $8.0 million to $35.0 million. These amounts are in excess of the minimum funding required under ERISA guidelines.

TECO Energy made contributions of $43.4 million and $1.2 million to the SERP in 2015 and 2014, respectively. TEC's portion of the contributions in 2015 and 2014 were $14.9 million and $0.8 million, respectively. TECO Energy's contribution in October 2015 to the SERP's trust was made in order to fully fund its SERP obligation following the signing of the Merger Agreement with Emera.

The execution of the Merger Agreement constituted a potential change in control under the trust; therefore, TECO Energy is required to maintain such funding as of the end of each calendar year, including 2015. The fully funded amount is equal to the aggregate present value of all benefits then in pay status under the SERP plus the current value of benefits that would become payable under the SERP to current participants. Since the SERP is fully funded, TECO Energy does not expect to make significant contributions to this plan in 2016.

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 July 1, 2001 is limited to a defined dollar benefit based on an age and service schedule. In 2016, TECO Energy expects to make a contribution of about $14.3 million. TEC's portion of the expected contribution is $9.3 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—TECO Energy**
**(including projected service and net of employee contributions)**

| *(millions)* | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| 2016 | $ 77.8 | $ 11.5 |
| 2017 | 49.5 | 11.9 |
| 2018 | 52.7 | 12.5 |
| 2019 | 59.2 | 13.0 |
| 2020 | 54.9 | 13.3 |
| 2021-2025 | 299.1 | 68.6 |

### 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. Effective Jan. 1, 2015, the employer matching contributions were 70% of eligible participant contributions with additional incentive match of up to 30% of eligible participant contributions based on the achievement of certain operating company financial goals. During the period from April 2013 to December 2014, 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 additional incentive match of up to 40%. For the years ended Dec. 31, 2015, 2014 and 2013, TECO Energy and its subsidiaries recognized expense totaling $11.1 million, $13.1 million and $11.3 million, respectively, related to the matching contributions made to this plan. TEC's portion of expense totaled $7.5 million, $10.2 million and $9.1 million for 2015, 2014 and 2013, respectively.

## 6. Short-Term Debt

At Dec. 31, 2015 and 2014, the following credit facilities and related borrowings existed:

### Credit Facilities

| | *Dec. 31, 2015* | | | *Dec. 31, 2014* | | |
|---|---|---|---|---|---|---|
| *(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 | $ 0.0 | $ 0.5 | $ 325.0 | $ 12.0 | $ 0.6 |
| 3-year accounts receivable facility (3) | 150.0 | 61.0 | 0.0 | 150.0 | 46.0 | 0.0 |
| **Total** | $ 475.0 | $ 61.0 | $ 0.5 | $ 475.0 | $ 58.0 | $ 0.6 |

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) Prior to Mar. 24, 2015, this was a 1-year facility. This 3-year facility matures Mar. 23, 2018.

At Dec. 31, 2015, these credit facilities required commitment fees ranging from 12.5 to 30.0 basis points. The weighted-average interest rate on borrowings outstanding under the credit facilities at Dec. 31, 2015 and 2014 was 0.89% and 0.7%, respectively.

*Tampa Electric Company Accounts Receivable Facility*

On Mar. 24, 2015, TEC and TRC amended and restated their $150 million accounts receivable collateralized borrowing facility in order to (i) appoint The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch (BTMU), as Program Agent, replacing the previous Program Agent, Citibank, N.A., (ii) add new lenders, and (iii) extend the scheduled termination date from Apr. 14, 2015 to Mar. 23, 2018, by entering into (a) an Amended and Restated Purchase and Contribution Agreement dated as of Mar. 24, 2015 between TEC and TRC and (b) a Loan and Servicing Agreement dated as of Mar. 24, 2015, among TEC as Servicer, TRC as Borrower, certain lenders named therein and BTMU, as Program Agent (the Loan Agreement). Pursuant to the Loan Agreement, TRC will pay program and liquidity fees, which total 65 basis points as of Dec. 31, 2015. Interest rates on the borrowings are based on prevailing asset-backed commercial paper rates, unless such rates are not available from conduit lenders, in which case the rates will be at an interest rate equal to, at TEC's option, either the BTMU's prime rate (or the federal funds rate plus 50 basis points, if higher) or a rate based on the London interbank deposit rate (if available) plus a margin. In addition, under the terms of the Loan Agreement, TEC has pledged as collateral a pool of receivables equal to the borrowings outstanding in the case of default. TEC continues to service, administer and collect the pledged receivables, which are classified as receivables on the balance sheet. As of Dec. 31, 2015, TEC and TRC were in compliance with the requirements of the Loan Agreement.

*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) extended 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, as borrower, 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.

On Sept. 30, 2014, TEC entered into an amendment of its $325 million bank credit facility, which reallocated commitments among the lenders and made certain 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, and Tampa Electric could cause the lien associated with this indenture to be released at any time.

*Issuance of Tampa Electric Company 4.20% Notes due 2045*

On May 20, 2015, TEC completed an offering of $250 million aggregate principal amount of 4.20% Notes due May 15, 2045 (the TEC 2015 Notes). The TEC 2015 Notes were sold at 99.814% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, estimated offering expenses and before settlement of interest rate swaps) of approximately $246.8 million. Net proceeds were used to repay short-term debt and for general corporate purposes. Until Nov. 15, 2044, TEC may redeem all or any part of the TEC 2015 Notes at its option at any time and from time to time at a redemption price equal to the greater of (i) 100% of the principal amount of the TEC 2015 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the TEC 2015 Notes to be redeemed, discounted at an applicable treasury rate (as defined in the indenture), plus 20 basis points; in either case, the redemption price would include accrued and unpaid interest to the redemption date. At any time on or after Nov. 15, 2044, TEC may, at its option, redeem the TEC 2015 Notes, in whole or in part, at 100% of the principal amount of the TEC 2015 Notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

*Issuance of Tampa Electric Company 4.35% Notes due 2044*

On May 15, 2014, TEC completed an offering of $300 million aggregate principal amount of 4.35% Notes due 2044 (the TEC 2014 Notes). The TEC 2014 Notes were sold at 99.933% of par. The offering resulted in net proceeds to TEC (after deducting underwriting discounts, commissions, estimated offering expenses and before settlement of interest rate swaps) of approximately $296.6 million. Net proceeds were used to repay short-term debt and for general corporate purposes. TEC may redeem all or any part of the TEC 2014 Notes at its option at any time and from time to time before Nov. 15, 2043 at a redemption price equal to the greater of (i) 100% of the principal amount of TEC 2014 Notes to be redeemed or (ii) the sum of the present value of the remaining payments of principal and interest on the notes to be redeemed, discounted at an applicable treasury rate (as defined in the indenture), 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 Nov. 15, 2043, TEC may at its option redeem the TEC 2014 Notes, in whole or in part, at 100% of the principal amount of the notes being redeemed plus accrued and unpaid interest thereon to but excluding the date of redemption.

*Purchase in Lieu of Redemption of Revenue Refunding Bonds*

On Mar. 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 Mar. 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 Mar. 19, 2008 to Mar. 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 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 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 Mar. 26, 2008 to Sept. 1, 2013. TEC is responsible for payment of the interest and principal associated with the Series 2007 B HCIDA Bonds.

As of Dec. 31, 2015, $232.6 million of bonds purchased in lieu of redemption were held by the trustee at the direction of TEC to provide an opportunity to evaluate refinancing alternatives.

## 8. Other Comprehensive Income

TEC reported the following OCI (loss) for the years ended Dec. 31, 2015, 2014 and 2013, 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 |
|---|---|---|---|
| **2015** | | | |
| Unrealized gain (loss) on cash flow hedges | $ 4.3 | $ (1.5) | $ 2.8 |
| Reclassification from AOCI to net income | 1.4 | (0.7) | 0.7 |
| Gain (Loss) on cash flow hedges | 5.7 | (2.2) | 3.5 |
| Total other comprehensive income (loss) | $ 5.7 | $ (2.2) | $ 3.5 |
| **2014** | | | |
| Unrealized gain (loss) on cash flow hedges | $ 0.0 | $ 0.0 | $ 0.0 |
| Reclassification from AOCI to net income | 1.1 | (0.4) | 0.7 |
| Gain (Loss) on cash flow hedges | 1.1 | (0.4) | 0.7 |
| Total other comprehensive income (loss) | $ 1.1 | $ (0.4) | $ 0.7 |
| **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 |

**Accumulated Other Comprehensive Loss**

| *(millions) As of Dec. 31,* | *2015* | *2014* |
|---|---|---|
| Net unrealized losses from cash flow hedges (1) | $ (3.6) | $ (7.1) |
| Total accumulated other comprehensive loss | $ (3.6) | $ (7.1) |

(1) Net of tax benefit of $2.3 million and $4.5 million as of Dec. 31, 2015 and 2014, 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. The company believes the claims in the pending actions described below are without merit and intends to defend the matters vigorously. TEC is unable at this time to estimate the possible loss or range of loss with respect to these matters. While the outcome of such proceedings is uncertain, management does not believe that their ultimate resolution will have a material adverse effect on the TEC's results of operations, financial condition or cash flows.

*Tampa Electric Legal Proceedings*

A 36-year-old man died from mesothelioma in March 2014. His estate and his family sued Tampa Electric as a result. The man allegedly suffered exposure to asbestos dust brought home by his father and grandfather, both of whom had been employed as insulators and worked at various job sites throughout the Tampa area. Plaintiff's case against Tampa Electric and 14 other defendants had alleged, among other things, negligence, strict liability, household exposure, loss of consortium, and wrongful death. Tampa Electric has agreed to a settlement which resolved the case in its entirety. The settlement is not material to TEC's financial position as of Dec. 31, 2015.

A 33-year-old man made contact with a primary line in June 2013, suffering severe burns. He and his wife sued Tampa Electric as a result. The man apparently made contact with the line as he was attempting to trim a tree at a local residence. Plaintiffs' case against Tampa Electric alleged, among other things, negligence and loss of consortium. Tampa Electric has agreed to a settlement which resolved the case in its entirety. The settlement is not material to TEC's financial position as of Dec. 31, 2015.

*Peoples Gas 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. 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 and a PGS contractor involved in the project, seeking damages for his injuries, remains pending, with a trial currently expected in late 2016.

**PGS Compliance Matter**

In 2015, FPSC staff presented PGS with a summary of alleged safety rule violations, many of which were identified during PGS' implementation of an action plan it instituted as a result of audit findings cited by FPSC audit staff in 2013. Following the 2013 audit and 2015 discussions with FPSC staff, PGS took immediate and significant corrective actions. The FPSC audit staff published a follow-up audit report that acknowledged the progress that had been made and found that further improvements were needed. As a result of this report, the Office of Public Counsel (OPC) filed a petition with the FPSC pointing to the violations of rules for safety inspections seeking fines or possible refunds to customers by PGS. On Feb. 25, 2016, the FPSC staff issued a notice informing PGS that the staff would be making a recommendation to the FPSC to initiate a show cause proceeding against PGS for alleged safety rule violations, with total potential penalties of up to $3.9 million. PGS is continuing to work with the OPC and FPSC staff to resolve the issues.

**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, 2015, TEC has estimated its ultimate financial liability to be $33.9 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Deferred credits and other liabilities" 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 rates.

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 for capacity payments and long-term leases, primarily for building space, vehicles, office equipment and heavy equipment. Rental expense for these leases included in "Regulated operations & maintenance – Other" on the Consolidated Statements of Income for the years ended Dec. 31, 2015, 2014 and 2013, totaled $3.8 million, $4.1 million and $2.3 million, respectively. In addition, Tampa Electric has other purchase obligations, including its outstanding commitments for major projects and long-term capitalized maintenance agreements for its combustion turbines. The following is a schedule of future minimum lease payments with non-cancelable lease terms in excess of one year, capacity payments under PPAs, and other net purchase obligations/commitments at Dec. 31, 2015:

| *(millions)* | *Capacity Payments* | *Operating Leases*(1) | *Net Purchase Obligations/Commitments*(1) | *Total* |
|---|---|---|---|---|
| *Year ended Dec. 31:* | | | | |
| 2016 | $ 14.6 | $ 5.7 | $ 218.3 | $ 238.6 |
| 2017 | 9.9 | 5.2 | 21.5 | 36.6 |
| 2018 | 10.1 | 4.7 | 9.6 | 24.4 |
| 2019 | 0.0 | 4.4 | 9.7 | 14.1 |
| 2020 | 0.0 | 4.1 | 4.7 | 8.8 |
| Thereafter | 0.0 | 14.5 | 20.0 | 34.5 |
| Total future minimum payments | $ 34.6 | $ 38.6 | $ 283.8 | $ 357.0 |

(1) 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.

**Guarantees and Letters of Credit**

At Dec. 31, 2015, TEC was not obligated under guarantees, but had the following letters of credit outstanding.

| *(millions)* | Year of Expiration | | | *Maximum* | |
|---|---|---|---|---|---|
| | | | *After* (1) | *Theoretical* | *Liabilities Recognized* |
| *Letter of Credit for the Benefit of:* | *2016* | *2017-2020* | *2020* | *Obligation* | *at Dec. 31, 2015* (2) |
| **TEC** | $ 0.0 | $ 0.0 | $ 0.5 | $ 0.5 | $ 0.1 |

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2020.
(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation under these agreements at Dec. 31, 2015. The obligations under these letters of credit include certain accrued injuries and damages when a letter of credit covers the failure to pay these claims.

**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, 2015, 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)* | *2015* | *2014* | *2013* |
|---|---|---|---|
| Natural gas sales, net | $ 0.8 | $ 0.3 | $ 18.3 |
| Administrative and general, net[(1)] | $ 69.4 | $ 22.5 | $ 27.2 |

(1) The 2015 increase in transactions with affiliates is attributable to shared services being provided to TEC from TSI, TECO Energy's centralized services company subsidiary, beginning in Jan. 1, 2015.

**Amounts due from or to affiliates at Dec. 31,**

| *(millions)* | *2015* | *2014* |
|---|---|---|
| Accounts receivable[(1)] | $ 2.3 | $ 2.4 |
| Accounts payable[(1)] | 15.9 | 9.7 |
| Taxes receivable[(2)] | 61.3 | 43.3 |
| Taxes payable[(2)] | 1.0 | 0.0 |

(1) Accounts receivable and accounts payable were incurred in the ordinary course of business and do not bear interest.
(2) Taxes receivable are due from, and taxes payable are due to, TECO Energy.

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 for the year ended Dec. 31, 2013 to Ausley McMullen, P.A. of which Mr. Ausley (who was a director of TEC, 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 719,000 customers in West Central Florida. Its PGS division is engaged in the purchase, distribution and marketing of natural gas for approximately 361,000 residential, commercial, industrial and electric power generation customers in the State of Florida.

| *(millions)* | Tampa Electric | PGS | Eliminations | TEC |
|---|---|---|---|---|
| **2015** | | | | |
| Revenues - external | $ 2,017.7 | $ 401.5 | $ 0.0 | $ 2,419.2 |
| Sales to affiliates | 0.6 | 6.0 | (6.6) | 0.0 |
| Total revenues | 2,018.3 | 407.5 | (6.6) | 2,419.2 |
| Depreciation and amortization | 256.7 | 56.8 | 0.0 | 313.5 |
| Total interest charges | 95.1 | 14.5 | 0.0 | 109.6 |
| Provision for income taxes | 143.6 | 21.9 | 0.0 | 165.5 |
| Net income | 241.0 | 35.3 | 0.0 | 276.3 |
| Total assets | 6,637.1 | 1,099.0 | (9.4) | 7,726.7 |
| Capital expenditures | 592.6 | 94.0 | 0.0 | 686.6 |
| **2014** | | | | |
| Revenues - external | $ 2,020.5 | $ 398.5 | $ 0.0 | $ 2,419.0 |
| Sales to affiliates | 0.5 | 1.1 | (1.6) | 0.0 |
| Total revenues | 2,021.0 | 399.6 | (1.6) | 2,419.0 |
| Depreciation and amortization | 248.6 | 54.0 | 0.0 | 302.6 |
| Total interest charges | 92.8 | 13.8 | 0.0 | 106.6 |
| Provision for income taxes | 133.2 | 22.7 | 0.0 | 155.9 |
| Net income | 224.5 | 35.8 | 0.0 | 260.3 |
| Total assets | 6,234.4 | 1,047.0 | (7.1) | 7,274.3 |
| Capital expenditures | 582.1 | 88.9 | 0.0 | 671.0 |
| **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 | 422.3 | 79.0 | 0.0 | 501.3 |

**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.

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

| | Dec. 31, | |
|---|---|---|
| *(millions)* | *2015* | *2014* |
| Beginning balance | $ 5.3 | $ 4.8 |
| Additional liabilities | 0.9 | 0.1 |
| Revisions to estimated cash flows | (0.5) | 0.2 |
| Other [(1)] | 0.3 | 0.2 |
| Ending balance | $ 6.0 | $ 5.3 |

(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, 2015, all of TEC's physical contracts qualify for the NPNS exception.

The derivatives that are designated as cash flow hedges at Dec. 31, 2015 and 2014 are reflected on TEC's Consolidated Balance Sheets and classified accordingly as current and long term assets and liabilities on a net basis as permitted by their respective master netting agreements. There were no derivative assets as of Dec. 31, 2015 and 2014. Derivative liabilities totaled $26.2 million and $42.7 million as of Dec. 31, 2015 and 2014, respectively. There are minor offset amount differences between the gross derivative assets and liabilities and the net amounts presented on the Consolidated Balance Sheets. There was no collateral posted with or received from any counterparties.

All of the derivative asset and liabilities at Dec. 31, 2015 and 2014 are designated as hedging instruments, which primarily are derivative hedges of natural gas contracts to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers. The corresponding effect of these natural gas related derivatives on the regulated utilities' fuel recovery clause mechanism is reflected on the Consolidated Balance Sheets as current and long term regulatory assets and liabilities. Based on the fair value of the instruments at Dec. 31, 2015, net pretax losses of $24.1 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Statements of Income within the next twelve months.

The Dec. 31, 2015 and 2014 balance in AOCI related to the cash flow hedges and interest rate swaps (unsettled and previously settled) is presented in **Note 8**.

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, 2015, 2014 and 2013, all hedges were effective. The derivative after-tax effect on OCI and the amount of after-tax gain or loss reclassified from AOCI into earnings for the years ended Dec. 31, 2015, 2014 and 2013 is presented in **Note 8**. Gains and losses were the result of interest rate contracts and the reclassifications to income were reflected in Interest expense.

The maximum length of time over which TEC is hedging its exposure to the variability in future cash flows extends to Nov. 30, 2017 for financial natural gas contracts. The following table presents TEC's derivative volumes that, as of Dec. 31, 2015, are expected to settle during the 2016 and 2017 fiscal years:

| *(millions)* | Natural Gas Contracts (MMBTUs) | |
|---|---|---|
| Year | Physical | Financial |
| 2016 | 0.0 | 27.6 |
| 2017 | 0.0 | 5.0 |
| Total | 0.0 | 32.6 |

TEC is exposed to credit risk by 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, 2015, 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 generally do not require a nonperformance risk adjustment 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.

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 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.

## 14. Fair Value Measurements

### Items Measured at Fair Value on a Recurring Basis

Accounting guidance governing fair value measurements and disclosures provides that fair value represents the amount that would be received in selling an asset or the amount that would be paid in transferring a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that is determined based upon assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, accounting guidance also establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1: Observable inputs, such as quoted prices in active markets;

Level 2: Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and

Level 3: Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities are measured at fair value based on one or more of the following three valuation techniques noted under accounting guidance:

*(A)* Market approach: Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities;

*(B)* Cost approach: Amount that would be required to replace the service capacity of an asset (replacement cost); and

*(C)* Income approach: Techniques to convert future amounts to a single present amount based upon market expectations (including present value techniques, option-pricing and excess earnings models).

The fair value of financial instruments is determined by using various market data and other valuation techniques.

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, 2015 and 2014. 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.

**Recurring Derivative Fair Value Measures**

| | *As of Dec. 31, 2015* | | | |
|---|---|---|---|---|
| *(millions)* | *Level 1* | *Level 2* | *Level 3* | *Total* |
| **Liabilities** | | | | |
| Natural gas swaps | $ 0.0 | $ 26.2 | $ 0.0 | $ 26.2 |

| | *As of Dec. 31, 2014* | | | |
|---|---|---|---|---|
| *(millions)* | *Level 1* | *Level 2* | *Level 3* | *Total* |
| **Liabilities** | | | | |
| Natural gas swaps | $ 0.0 | $ 42.7 | $ 0.0 | $ 42.7 |

Natural gas swaps are OTC swap instruments. The fair value of the swaps is estimated utilizing the market approach. The price of swaps is calculated using observable NYMEX quoted closing prices of exchange-traded futures. These prices are applied to the notional quantities 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, 2015, the fair value of derivatives was not materially affected by nonperformance risk. There were no Level 3 assets or liabilities for the periods presented.

**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.

Tampa Electric 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 157 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 variable interests. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. Tampa Electric 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, and have the obligation or right to absorb losses or benefits and hence remain the primary beneficiaries. As a result, Tampa Electric is not required to consolidate any of these entities. Tampa Electric purchased $33.6 million, $25.7 million and $22.1 million, under these PPAs for the three years ended Dec. 31, 2015, 2014 and 2013, respectively.

TEC does not provide any material financial or other support to any of the VIEs it is involved with, nor is TEC under any obligation to absorb losses associated with these VIEs. In the normal course of business, TEC's involvement with these VIEs does not affect its Consolidated Balance Sheets, Statements of Income or Cash Flows.

### 16. Mergers and Acquisitions

**Pending Merger with Emera Inc.**

On Sept. 4, 2015, TECO Energy and Emera entered into the Merger Agreement. Upon closing of the Merger, TECO Energy will become a wholly owned indirect subsidiary of Emera.

Upon the terms and subject to the conditions set forth in the Merger Agreement, which was unanimously approved and adopted by the board of directors of TECO Energy, at the effective time, Merger Sub will merge with and into TECO Energy with TECO Energy continuing as the surviving corporation.

Pursuant to the Merger Agreement, upon the closing of the Merger, which is expected to occur in the summer of 2016, each issued and outstanding share of TECO Energy common stock will be cancelled and converted automatically into the right to receive $27.55 in cash, without interest (Merger Consideration). This represents an aggregate purchase price of approximately $10.4 billion including assumption of approximately $3.9 billion of debt (of which TEC’s portion of debt was $2.3 billion).

The closing of the Merger is subject to certain conditions, including, among others, (i) approval of TECO Energy shareholders representing a majority of the outstanding shares of TECO Energy common stock (which approval was obtained at the special meeting of shareholders held on Dec. 3, 2015), (ii) expiration or termination of the applicable Hart-Scott-Rodino Act waiting period (which expired on Feb. 5, 2016), (iii) receipt of all required regulatory approvals, including from the FERC, the NMPRC and the Committee on Foreign Investment in the United States (which, with respect to the FERC, was obtained on Jan. 20, 2016), (iv) the absence of any law or judgment that prevents, makes illegal or prohibits the closing of the Merger, (v) the absence of any material adverse effect with respect to TECO Energy and (vi) subject to certain exceptions, the accuracy of the representations and warranties of, and compliance with covenants by, each of the parties to the Merger Agreement.

TECO Energy is also subject to a “no shop” restriction that limits its ability to solicit alternative acquisition proposals or provide nonpublic information to, and engage in discussion with, third parties.

The Merger Agreement contains certain termination rights for both TECO Energy and Emera. Either party may terminate the Merger Agreement if (i) the closing of the Merger has not occurred by Sept. 30, 2016 (subject to a 6-month extension if required to obtain necessary regulatory approvals), (ii) a law or judgment preventing or prohibiting the closing of the Merger has become final, (iii) TECO Energy’s shareholders do not approve the Merger or (iv) TECO Energy’s board of directors changes its recommendation so that it is no longer in favor of the Merger. If either party terminates the Merger Agreement because TECO Energy’s board of directors changes its recommendation, TECO Energy must pay Emera a termination fee of $212.5 million. If the Merger Agreement is terminated under certain other circumstances, including the failure to obtain required regulatory approvals, Emera must pay TECO Energy a termination fee of $326.9 million.

### 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, 2015 (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, 2015 based on the 2013 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, 2015.

TECO Energy's internal control over financial reporting as of Dec. 31, 2015 has been audited by PricewaterhouseCoopers LLP, an independent registered certified public accounting firm, as stated in their report which appears herein.

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 were no changes 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, 2015 (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, 2015 based on the 2013 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, 2015.

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.**

On Feb. 24, 2016, TECO Energy and TECO Finance entered into Amendment No. 3 (the Amendment) to its Fourth Amended and Restated Credit Agreement (the TECO Credit Facility) with JPMorgan Chase Bank, N.A., as administrative agent, and certain lenders named therein. The Amendment provides that the closing of the Merger will not constitute an event of default under the TECO Credit Facility. The foregoing description of the Amendment is qualified in its entirety by reference to the Amendment, which is filed as Exhibit 10.59 to this report, and is incorporated herein by reference.

# PART III

## Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

### Executive Officers

The information required by Item 10 concerning executive officers of the registrant is included under the caption "Executive Officers of the Registrant" in Item 1 – Business of this report and incorporated herein by reference.

### Directors

The nine directors listed below were elected at the company's 2015 Annual Shareholders Meeting for terms expiring at the next Annual Shareholder's Meeting or until their successors are elected and qualified.

**James L. Ferman, Jr.**
Age 72
Director since 1985
Presiding Director effective as of 2015 Annual Meeting

President, Ferman Motor Car Company, Inc.

*Committees*
Compensation Committee
Governance and Nominating Committee (Chair)

*Other Directorships*
The Bank of Tampa and its holding company,
The Tampa Bay Banking Company (Chair)

Mr. Ferman has been President of Ferman Motor Car Company, Inc., an automobile dealership business headquartered in Tampa, Florida, since prior to 2011. In addition to the directorships named above, he also serves as a Trustee on the Boards of Emory University and the University of Tampa.

Key Attributes, Experience and Skills: As a result of Mr. Ferman's position as President of Ferman Motor Car Company, one of the largest vehicle dealership groups in the United States, Mr. Ferman brings significant business management and leadership experience to the Board. Also, his position at such a prominent Tampa-area business and his trustee position at the University of Tampa, as well as former chairman positions he has held at several local charitable and business organizations, such as at the Greater Tampa Chamber of Commerce, brings significant community involvement and recognition to the Board. These positions, and his former chairmanship of the Governance Committee of the Board of Trustees of Emory University, also provide additional leadership experience to the Board and additional insight to our Governance and Nominating Committee. Through his long tenure on our Board, he has gained significant industry knowledge and a long-term perspective on our businesses. His other directorships also provide experience in finance and risk management.

**Evelyn V. Follit**
Age 69
Director since 2012

President, Follit Associates
Former Senior Vice President, RadioShack Corporation

*Committees*
Audit Committee
Governance and Nominating Committee

*Other Directorships*
Beall's, Inc.
MarineMax, Inc.

Ms. Follit has been the President of Follit Associates, a corporate technology and executive assessment consulting firm based in Naples, Florida, since she founded the firm in 2007. From 1997 to 2005, she was an executive of RadioShack Corporation, a consumer electronics retail company, where she held the positions of Senior Vice President, Chief Information Officer, and Chief Organizational Enabling Services Officer. Ms. Follit was previously a director of Winn-Dixie Stores, Inc.

Key Attributes, Experience and Skills: As a result of Ms. Follit's over 20 years in leadership positions with major corporations, Ms. Follit brings significant business management and leadership experience to the Board, and in particular brings executive-level expertise to the Board in the areas of information technology, human resources and operations management. Her consulting practice also allows her to provide the Board with her insight into the other industries her firm serves and current business trends. These positions, and her positions on the Audit and Governance and Nominating Committees of MarineMax, Inc. and the Audit and Compensation Committees of the Board of Beall's Inc., provide additional leadership experience and insight to the Board and its committees. Her current and former directorships also provide knowledge in finance and of local markets.

**Sherrill W. Hudson**
Age 73
Director since 2003

*Committees*
Finance Committee

Chairman of the Board
Former Executive Chairman
of the Board and Chief
Executive Officer of TECO Energy

*Other Directorships*
CBIZ, Inc.
Lennar Corporation
United Insurance Holdings Corp.

Mr. Hudson has been the non-executive Chairman of the company's Board since January 2013, and prior to that was Executive Chairman of the Board from August 2010. Mr. Hudson was the company's Chief Executive Officer from 2004 to 2010. He was formerly the Managing Partner for the South Florida offices of the public accounting firm, Deloitte & Touche LLP, in Miami, Florida. Mr. Hudson was previously a director of Publix Supermarkets, Inc.

Key Attributes, Experience and Skills: Mr. Hudson brings significant leadership and business, finance and accounting experience and expertise gained through both his positions at TECO Energy and through his 37-year tenure at Deloitte & Touche, which included 19 years as the Managing Partner for the South Florida offices. His former position as our CEO provides valuable industry knowledge and risk management experience, which he also obtained through his oversight and advising of clients in the utility and other industries while at Deloitte & Touche. Also through his work at Deloitte & Touche, he has experience working with and exposure to many Board and management structures, and insight into the issues facing businesses, from financial and accounting, as well as operational, perspectives. His community service, through membership on the boards of several charitable and business organizations and committees, brings additional community involvement and recognition and leadership experience to the Board. Through his other board memberships, he is familiar with several other significant Florida companies, their governance and management structures, and the local business environment.

**Joseph P. Lacher**
Age 70
Director since 2006

*Committees*
Audit Committee (Chair)
Finance Committee
Governance and Nominating Committee

Former President of Florida Operations for
BellSouth Telecommunications, Inc.

Mr. Lacher is the former President of Florida operations for BellSouth Telecommunications, Inc., a telecommunications services company in Miami, Florida, serving in such role from 1991 until his retirement in 2005. Mr. Lacher was previously a director of Perry Ellis International, Inc.

Key Attributes, Experience and Skills: Mr. Lacher's tenure as former President of Florida operations for BellSouth Telecommunications, Inc. provides significant leadership and management experience. This experience is especially relevant for our Board as it involved a business regulated by the same entity that regulates our Florida utility businesses, and therefore, he is familiar with the unique issues presented in this area. In addition, through this work, he has experience in dealing with deregulation issues. He was also Chair of the Audit Committee at Perry Ellis International, Inc., and is Vice Chairman of the

Board of Goodwill Industries of South Florida (and was previously the Chairman), which provides additional board leadership experience and insight for our board committees.

| | |
|---|---|
| **Loretta A. Penn** | *Committees* |
| Age 66 | Compensation Committee |
| Director since 2005 | Governance and Nominating Committee |

President of PECC, LLC
Former President of Spherion Staffing Services

Ms. Penn has served as the president of PECC, LLC, an executive coaching and consulting company based in Fairfax Station, Virginia, since she founded the company in 2013. She is the former President of Spherion Staffing Services, a division of SFN Group, Inc. (formerly known as Spherion Corporation), a staffing and professional services company, in McLean, Virginia, where she served in such role from December 2008 to December 2011. Ms. Penn also served as the Senior Vice President of SFN Group from November 2007 to December 2011. In addition to other executive-level experience in the recruiting and staffing industry, Ms. Penn was previously associated with the IBM Corporation for ten years in regional executive management, sales and marketing.

Key Attributes, Experience and Skills: Ms. Penn's increasing levels of responsibility and seniority at Spherion, including her most recent position as the President of its largest division, provided valuable business, leadership and management experience. Her role at Spherion brought her into contact with executives in a diverse array of industries and areas of the country, and her insight into these other industries and current business trends is valuable to the Board. Her many years of experience in the recruiting and staffing industry provide expertise in human resources issues, which are important issues to our businesses and to our Compensation Committee. Through her decade-long tenure at IBM Corporation, she also has experience in the technology industry, which is an important area for our current operations and plans for the future.

| | |
|---|---|
| **John B. Ramil** | *Committees* |
| Age 60 | Finance Committee |
| Director since 2008 | |
| President and Chief Executive Officer of TECO Energy, Inc. | *Other Directorships*<br>Blue Cross Blue Shield of Florida, Inc. (chairman of Audit and Compliance Committee, member of Finance Committee) |

Mr. Ramil has been TECO Energy's President and Chief Executive Officer since 2010. During his 40-year career with the company, he has held several leadership positions, including as President and Chief Operating Officer of TECO Energy from 2004 to 2010, President of Tampa Electric Company, Executive Vice President of TECO Energy, Chief Financial Officer for TECO Energy, and Vice President-Energy Services & Planning for Tampa Electric. He has also held a variety of positions in engineering, operations, marketing, customer service and environmental, and has served as president of various other TECO Energy subsidiaries.

Key Attributes, Experience and Skills: Mr. Ramil's long tenure with the company, in a variety of positions, brings extensive knowledge of our businesses, our industry, and significant business, operating and leadership experience to the Board. His experience as TECO Energy's Chief Financial Officer also provides additional financial expertise, and several of his positions, including his current role as Chief Executive Officer, bring risk management experience to the Board. In addition, through his work with non-profit and business groups, including his positions as Chairman of the Board of the University of South Florida and a board member of the Edison Electric Institute, Mr. Ramil provides community and industry involvement and recognition for the company, as well as expertise in leadership development and governance issues.

**Tom L. Rankin**
Age 75
Director since 1997

*Committees*
Audit Committee
Finance Committee (Chair)

Former Chairman of the Board and
Chief Executive Officer of Lykes Energy, Inc.

Mr. Rankin has been an investor based in Tampa, Florida, since prior to 2011. Mr. Rankin is the former Chairman of the Board and Chief Executive Officer of Lykes Energy, Inc. and Lykes Bros. Inc. Mr. Rankin was previously a director of Media General, Inc.

Key Attributes, Experience and Skills: Mr. Rankin brings significant industry experience to the Board through his leadership positions at Lykes Energy, Inc., the former holding company for Peoples Gas System. In addition to his knowledge of the gas utility industry, he has gained valuable experience in the electric utility industry through his tenure on our Board. His leadership role at Lykes Bros. Inc. provides experience in managing the operations of several other types of businesses, as well. His position at Lykes, as well as his investing experience, also provides important insight into finance matters. He was also on the Audit and Governance Committees of Media General, Inc., which provides additional insight and experience for the issues faced by our Board and its committees.

**William D. Rockford**
Age 70
Director since 2000

*Committees*
Finance Committee
Compensation Committee

Former President, CFO and COO of Primary
Energy Ventures, LLC

Mr. Rockford is the former President, Chief Financial Officer and Chief Operating Officer of Primary Energy Ventures LLC, a power generation company located in Oak Brook, Illinois. He is also a former Managing Director of the financial services company, Chase Securities Inc., in New York, New York, where his responsibilities included the Global Power, Project Finance and Environmental Group.

Key Attributes, Experience and Skills: Mr. Rockford provides valuable leadership, management and energy industry experience, obtained through his positions at Primary Energy Ventures. Through his nearly 30-year career at Chase, Mr. Rockford has experience in providing capital markets, corporate finance, project finance and merger and acquisition advice to the utility industry, which adds valuable expertise in these areas to both the Board and to the Finance Committee. Mr. Rockford also has experience in commercial banking, which provides additional finance and risk management expertise to the Board and its committees.

**Paul L. Whiting**
Age 72
Director since 2004

*Committees*
Audit Committee (Audit Committee Financial Expert)
Compensation Committee (Chair)

President of Seabreeze Holdings, Inc.

*Other Directorships*
Sykes Enterprises, Incorporated (Chairman of the Board)
The Bank of Tampa and its holding company, The Tampa Bay Banking Company

Mr. Whiting, has been the President of Seabreeze Holdings, Inc., a private investments company located in Tampa, Florida, since prior to 2011. Previously, Mr. Whiting held various positions within Spalding & Evenflo Companies, Inc., including Chairman, Chief Executive Officer and Chief Financial Officer.

Key Attributes, Experience and Skills: As a result of his experience at the Spalding & Evenflo Companies, Mr. Whiting provides leadership, financial and business experience and expertise. His other board and committee memberships, including as Chairman of the Board and member of the Audit Committee at Sykes Enterprises, provide additional leadership experience, as well as exposure to other governance structures, and additional financial and risk management experience. His notable community service, including as founder, Trustee and former Board President of the Academy Prep Center of Tampa, Inc., a full scholarship, private college preparatory middle school for low-income children, is important to a business such as ours which values involvement in the communities we serve.

**Audit Committee**

The Board of Directors has established an Audit Committee in accordance with Section 3(a)(58)(A) of the Exchange Act. As indicated above, Ms. Follit and Messrs. Lacher, Rankin and Whiting are the members of the Audit Committee. Each member of the Audit Committee is an independent director under SEC rules and NYSE listing standards. The Board has determined that Messrs. Lacher, Rankin and Whiting meet the definition of "audit committee financial expert" under SEC rules.

**Code of Ethics**

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.

**Section 16(a) Beneficial Ownership Reporting Compliance**

Our executive officers and directors are required under Section 16(a) of the Securities Exchange Act of 1934 (the Exchange Act) to file reports of ownership and changes in ownership of our securities with the Securities and Exchange Commission. Copies of those reports must also be furnished to us. Based solely on a review of the copies of reports furnished to us with respect to 2015 and written representations that no other reports were required, we believe that our executive officers and directors have complied in a timely manner with all applicable Section 16(a) filing requirements, except that a Form 4 to report the disposition of shares resulting from the forfeiture of performance shares for Charles A. Attal was inadvertently filed late due to an administrative error.

**Item 11. EXECUTIVE COMPENSATION.**

**Compensation Committee Report**

The Compensation Committee has reviewed and discussed the Compensation Discussion & Analysis set forth below with management and, based on this review and discussion, has recommended to the Board that it be included in this Annual Report on Form 10-K.

By the Compensation Committee:

| | |
|---|---|
| Paul L. Whiting (Chairman) | Loretta A. Penn |
| James L. Ferman, Jr. | William D. Rockford |

**Compensation Discussion and Analysis**

This Compensation Discussion and Analysis (CD&A) explains how we use different elements of compensation to achieve the goals of our executive compensation program and how we determine the amounts of each component to pay. Our executive compensation program is designed to tie a significant portion of executive pay directly to company performance.

The term "named executive officers" as used throughout this CD&A refers to the following executive officers who are currently employed with the company and are named in the Summary Compensation Table:

- John B. Ramil, President and Chief Executive Officer
- Sandra W. Callahan, Senior Vice President – Finance and Accounting and Chief Financial Officer
- Gordon L. Gillette, President, Tampa Electric Company
- Charles A. Attal III, Senior Vice President – General Counsel and Chief Legal Officer and Chief Ethics and Compliance Officer
- Phil L. Barringer, Senior Vice President – Corporate Services and Chief Human Resources Officer

The term "named executive officers" also refers to Clark Taylor, formerly President, TECO Coal LLC, who is no longer employed by the company due to the sale of the company's subsidiary, TECO Coal LLC, in September 2015.

The Compensation Committee of the Board (the Committee) makes decisions with respect to CEO compensation and equity-based incentives, after consultation with the Board. The Board makes all decisions with respect to the compensation of our other named executive officers after considering the recommendations of the Compensation Committee. Therefore, in all cases where we refer to the Committee's actions (except with respect to CEO compensation or equity-based incentives), such actions are carried out through Board approval, upon the recommendation of the Committee.

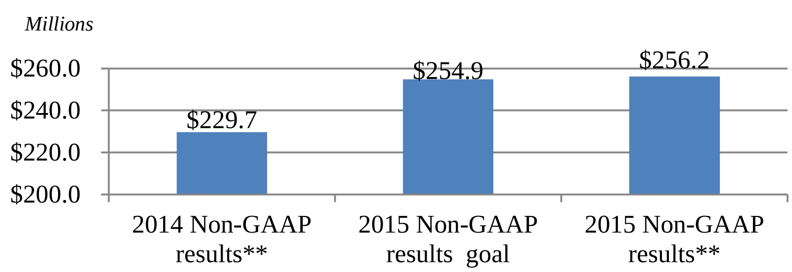
**Executive Summary**

**2015 Executive Compensation Highlights**

- Pay is targeted at the market median* with *an emphasis on stock and performance-based pay*
    - Our named executive officers' total pay was positioned at the market median, consistent with our compensation philosophy
    - Their pay packages are heavily weighted towards long-term incentive awards
    - For example, over 80% of our CEO's total compensation is at risk depending on company performance
    - Seventy percent of the 2015 long-term incentive component consisted of performance shares dependent on earnings per share growth and relative total shareholder return

*Market median compensation is determined using the data provided by the Compensation Committee's independent compensation consultant, as described under **Pay Peer Group** and **Compensation Review Process**.

- *The financial results goal set for the 2015 annual incentive program was 11% higher* than 2014 results




** The tables entitled "Reconciliation of GAAP net income from continuing operations to non-GAAP results" included in **Item 7- Management's Discussion and Analysis** above and in our Annual Report on Form 10-K for the year ended December 31, 2014 show how non-GAAP results are reconciled to GAAP net income.

- Our executive compensation program *incentivizes our leaders to increase shareholder value* as evidenced by the following achievements and their relationship to our compensation program
    - We delivered total shareholder return (TSR) of over 30% in 2015
    - Our TSR outperformed the S&P 500 and the utility industry over the one-, three- and five-year periods ended December 31, 2015
    - A new internal measure for the performance shares was added in 2015, which was designed to provide an incentive for continued earnings growth

- *We engage with shareholders* and take into consideration their input to our executive compensation program, and seek to incorporate compensation practices they value
    - In early 2015, we implemented an internal measure of performance for our performance shares based on robust earnings growth which aligned with our long-term strategy and focused on a measure that is important to our company and industry, while retaining an element of relative total shareholder return; this change was based, in part, on feedback we received from shareholders
    - Over the past several years, we made changes to our program that shareholders were asking for, such as strengthening our stock retention guidelines and adopting policies prohibiting pledging and hedging and providing for clawbacks

- Our program has for many years incorporated *important risk mitigating features and practices that shareholders value*

**Practices we employ**

✓ We have Stock Ownership Guidelines of five times base salary for the CEO and three times base salary for other executive officers, and five times annual retainer for directors

✓ Our Claw-Back Policy applies to all officers in the event of any financial restatement if a lower payment would have been made to the officer under the annual incentive plan based upon the restated financial results, regardless of the cause of the restatement (whether or not due to fraud or the fault of the officer)

✓ Our Hedging Policy prohibits officers and directors from entering into hedging transactions with respect to our stock

✓ Our Pledging Policy prohibits officers and directors from pledging our stock

✓ The Compensation Committee has an independent compensation consultant, Steven Hall & Partners (SH&P), who performs no other services for the company

**Practices we do not employ**

☒ We do not pay dividends on unvested performance shares, unless and until such shares vest

☒ We do not have employment agreements with our officers

☒ We do not provide extra pension service credits to executives

☒ We do not provide tax gross-ups on any benefits or perquisites, and our Compensation Committee determined not to provide excise tax gross-ups in any new change-in-control agreements

☒ We do not provide significant perquisites; in 2015, perquisites or personal benefits (payments not available to all employees) were less than $10,000 for each continuing named executive officer

**Pay for Performance Alignment**

Our executive compensation program ties a significant portion of executive pay directly to company performance in order to link the interests of our executives to the long-term interests of our shareholders.

- Over 80% of our CEO's compensation and, on average, approximately two-thirds of the other named executive officers' compensation, is at risk and varies depending on corporate and individual performance
- 70% of long-term incentive awards are performance shares (pre-2015 grants are tied to TSR as compared with the peer companies in the Dow Jones Conventional Electricity and Multi Utility subsectors of its Utilities Index ("relative total shareholder return"), and 2015 grants of performance shares are tied primarily to earnings growth (with the ability to earn more shares if TSR is in the top quartile of the industry))
- 80% of annual incentive plan awards are based on the achievement of challenging corporate financial goals and 20% are based on achievement of individual goals designed to help the company achieve its overall business plan goals
- No annual incentive awards are paid unless a threshold level of income is achieved
- Incentive plans are designed to avoid encouraging excessive risk-taking

We set well-defined, challenging goals for the annual incentive program and performance-based long-term incentives.

- Annual incentive goals are consistent with the earnings guidance we give to investors, which provides incentives to management to create value consistent with the company's business strategy
- Beginning in 2015, long-term incentive grants included a new performance measure tied to achievement of earnings growth targeted at 5% per year (while retaining a component based on relative total shareholder return), which was designed to incentivize continued high performance

We continually evaluate and update the executive compensation program to ensure that it meets the objectives to attract, retain and motivate highly qualified executives.

**Consideration of Last Year's "Say on Pay" Vote**

At the 2015 annual meeting, shareholders were asked to cast an advisory vote on the compensation of our named executive officers as disclosed in the proxy statement for the 2015 annual meeting, and our shareholders approved the proposal, with over 94% of the votes cast in favor.

The Committee believed that this overwhelming support of the program was in part due to the changes the Committee implemented in early 2015 based on feedback received from shareholder engagement efforts, which included modifications to the long-term incentive program to add a new performance measure tied to robust, long-term earnings growth, while maintaining an incentive to outperform peers on a total return basis.

With the change made to the performance measure in the long-term incentive program described above, as well as changes made in recent years, such as adopting strong policies on pledging, hedging and clawbacks, the Committee is honoring its commitment to continually evaluate and update the program to ensure it continues to attract, retain and motivate highly qualified executives.

**Philosophy and Objectives of our Executive Compensation Program**

We provide competitive compensation to attract and retain the talent needed to successfully manage and build our businesses. Total compensation is targeted at the 50th percentile of companies of similar size in our industry, which provides fair compensation for the executives that is cost-effective for the company.

Payouts under the annual incentive award plan are based on both financial goals and individual qualitative goals based on the company's business plan objectives for that year. Payouts under the performance share awards are based on relative performance goals (and beginning in 2015, are also based on EPS growth). The 2015 short and long-term incentive programs capped potential awards at 150% and 200% of the target amount, respectively. This mix of goals ensures that multiple aspects of business success are considered in determining compensation.

**2015 Achievements**

Following many years of successful recovery from merchant power investments in the early 2000s, in 2015 we achieved our goal to exit non-core operations and focus on regulated utility businesses. This strategy was completed with the sale of our last non-utility business, TECO Coal, in late 2015. The strategy was also furthered by the continued integration of NMGC, which we acquired in 2014, as an addition to our regulated utility portfolio.

In September 2015, the company entered into the Merger Agreement described in **Item 1 – Business Section**. The Merger Agreement contemplates that upon closing, TECO Energy would become a wholly owned indirect subsidiary of Emera. Under the terms of the all-cash deal, if the transaction closes as contemplated by the Merger Agreement, TECO Energy shareholders will receive $27.55 per common share, a premium of (i) approximately 48% to the closing price of TECO Energy's common stock on the New York Stock Exchange on July 15, 2015, which was the last trading day prior to the date that TECO Energy publicly disclosed that it was exploring strategic alternatives, and (ii) approximately 25% to the highest trading price of TECO Energy's common stock for the fifty-two-week period ended on July 15, 2015. In December 2015, the company obtained approval from its shareholders for the transaction.

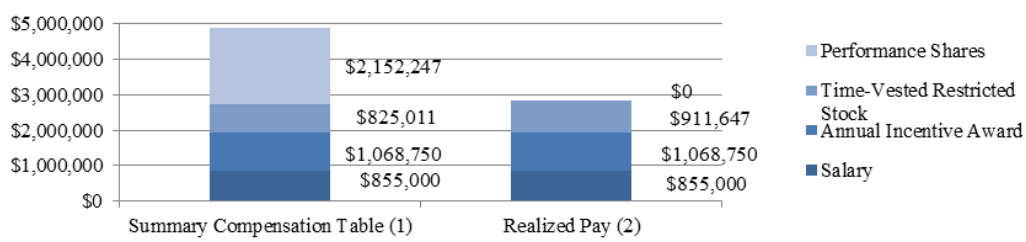
In light of the achievements described above, our stock price significantly outperformed the S&P 500 and the utility industry in 2015 and over the three and five years ending Dec. 31, 2015. See **Item 5 - Shareholder Return Performance Graph**, showing the cumulative total shareholder return of TECO Energy's common stock for a five-year period compared to the S&P 500 and utility industry.

**Realized Pay**

Because our compensation program is designed to align the interests of our executives with those of our shareholders, the amounts actually received by our executives are significantly impacted by the actual results achieved. For example, the grants of performance shares that were scheduled for vesting in 2014 and 2015, which were based on relative total shareholder return compared to industry peers, were each completely forfeited.

The table below compares 2015 compensation paid to John B. Ramil as reported in the Summary Compensation Table to the value of the pay realized by Mr. Ramil in 2015. The primary difference between our CEO's realized pay amount and amounts reported in the **2015 Summary Compensation Table** is the accounting value attributed to his long-term incentive grants, which represent compensation that may have been realized by him in future years, versus the value of the long-term incentive awards that vested in 2015 (which, as described above, were forfeited in the case of the performance shares).

***2015 Realized Pay for our CEO was 42% lower than Summary Compensation Table Pay***




| Total: | $4,901,008 | $2,835,397 |
|---|---|---|

(1) **2015 Summary Compensation Table** pay includes base salary, annual incentive award paid for 2015, and the grant date fair value of long-term equity incentive compensation granted in 2015.

(2) Realized pay includes base salary, annual incentive award paid for 2015, and the value of long-term equity incentive compensation that vested in 2015.

**How We Make Compensation Decisions**

*Role of the Compensation Committee*

The Compensation Committee carries out its responsibilities by (a) evaluating the executive officers' performance annually, (b) reviewing peer group compensation as compared to the compensation of the company's executive officers and tally sheet information showing the total compensation for each executive officer, (c) reviewing and discussing information regarding the company's strategic plans and (d) then recommending (or approving, in the case of the CEO) salaries and annual incentive goals and target incentive awards based on the Committee's review and evaluation of this information. The Committee also reviews the company's performance and the level of achievement of the annual incentive goals, and it recommends (or approves, in the case of the CEO) the level of payment for the annual incentive awards based on this review of company and individual performance. The Committee also reviews information with respect to equity incentive awards, such as market data, and makes such awards (or recommends such awards, with respect to non-employee directors). The Committee also meets to consider other compensation-related issues, such as the design of the equity incentive plan and awards made under that plan and the director compensation program. The Committee also considers external developments related to executive compensation, such as best practices from an investor or external stakeholder perspective, and developments based on new or pending laws or regulations. In fulfilling these responsibilities, the Committee receives input from its independent compensation consultant, SH&P.

*Role of Management*

Management (primarily the CEO and Chief Human Resources Officer) provides the Compensation Committee with information, ideas and input regarding compensation decisions, discusses this information and the recommendations of the Committee's compensation consultant in detail with the Committee, and answers questions. To carry out this role, with the Committee Chairman's consent, management may interface directly with the Committee's executive compensation consultant to give its input on the design of compensation programs and policies, and the development of compensation recommendations. Information regarding the Committee's consultant and the Committee's authority to engage advisors is described under *Role of the Compensation Consultant* below.

The Committee's charter allows the Committee to form and delegate authority to subcommittees, and the equity incentive plan allows the Committee to delegate to one or more executive officers of the company the power to make small equity incentive awards to employees (other than executive officers). The Committee has delegated authority to management to make small restricted stock grants to non-executive officers and key employees and to allow previously granted options to be exercised for their full term and time-vested restricted stock to vest following the termination of employment by certain employees. Management provides a report to the Committee when it exercises this delegated authority.

*Role of the Compensation Consultant*

Pursuant to the Committee's charter, it has authority and necessary funding to retain and terminate any compensation consultant, outside legal counsel or other advisor as the Committee may deem appropriate in its sole discretion, after considering all factors relevant to the advisor's independence, including the factors specified by applicable New York Stock Exchange listing standards. The Compensation Committee has sole authority and is directly responsible for approving the advisor's fees and other retention terms and for overseeing the work of the advisor.

The Committee used SH&P as its independent compensation consultant for 2015. SH&P did not provide any other services to the company in 2015, and SH&P did not receive any fees or compensation from the company other than the customary fees it received as the Committee's independent compensation consultant. The Committee conducted an assessment of SH&P's independence in accordance with New York Stock Exchange listing standards and confirmed that SH&P's work for the Committee did not raise any conflict of interest.

SH&P provides research, data analyses, survey information and design expertise to assist the Committee in developing compensation programs for executives and directors. In addition, SH&P provides the Committee with information regarding regulatory developments and market trends related to executive compensation and governance practices. A representative of SH&P generally attends meetings of the Compensation Committee, is available to participate in executive sessions and communicates directly with the Compensation Committee and its Chairman.

*Maintaining a High Proportion of Performance-Based Pay*

Compensation decisions are made to keep a significant portion of each named executive officer's direct compensation variable and earned based upon performance. The table below shows, for the continuing named executive officers, the proportion of compensation tied to company performance relative to other elements of direct compensation in 2015, based on target values of each element.

| | John B. Ramil | Sandra W. Callahan | Gordon L. Gillette | Charles A. Attal | Phil L. Barringer |
|---|---|---|---|---|---|
| Base Salary | 18% | 31% | 37% | 34% | 34% |
| Annual Incentive Award (at target) | 18% | 21% | 26% | 20% | 18% |
| Time-Vested Restricted Stock (grant date value) | 18% | 13% | 10% | 13% | 13% |
| Performance Shares (grant date value) | 46% | 35% | 27% | 33% | 35% |

*Pay Peer Group*

The Compensation Committee reviews market data provided by its independent compensation consultant to help establish executive compensation levels, in order to provide compensation packages competitive with those of our peers. This market data includes compensation data and pay practices from both the company's peer group identified below and broader compensation survey data. For 2015, the market data that the Compensation Committee reviewed included publicly disclosed compensation data from a peer group (the Pay Peer Group) which was comprised of publicly-traded electric or electric and gas utility companies with revenues ranging between approximately one-half and two-times the company's revenues. The Pay Peer Group, which is used to help establish appropriate levels for total pay opportunities, only includes companies of approximately our size, whereas the TSR peer group described above is a broader group used to determine our TSR compared to the utility industry. The companies in the Pay Peer Group for 2015 were as follows:

| | | | |
|---|---|---|---|
| Alliant Energy Corp. | Hawaiian Electric Industries Inc. | Pepco Holdings, Inc. | SCANA Corp. |
| Avista Corporation | Integrys Energy Group, Inc. | Pinnacle West Capital Corp. | Westar Energy, Inc. |
| CMS Energy Corp. | NiSource Inc. | Portland General Electric Co. | Wisconsin Energy Corp. |
| Great Plains Energy Inc. | OGE Energy Corp. | | |

*Compensation Review Process*

After reviewing market data from its independent compensation consultant and other information described below, management developed 2015 target total compensation recommendations for each named executive officer (other than for the CEO, for whom management did not provide a recommendation), which were then submitted to the Committee for consideration. These recommendations were based on a review and assessment of the following:

- Proxy data from the companies in our Pay Peer Group
- Survey data
- Factors previously identified by the Committee, such as individual performance, time in position, scope of responsibility and experience

Total compensation for each named executive officer is generally targeted at the median of the market data for similar positions, while also taking into consideration the factors noted above. How market data is used in determining levels of compensation is discussed in more detail with respect to each element of compensation below.

The Compensation Committee annually reviews a tally sheet for each named executive officer, which shows each element of compensation discussed above, the total compensation paid to each executive officer for the past three years, and percentage changes year over year with respect to each element. These tally sheets also show the value of each executive officer's total equity holdings, for both vested and unvested or restricted holdings, and the amounts that would be payable to each executive officer in the event of voluntary termination, termination for cause, termination without cause, and termination in connection with a change in control of the company. This information provides the Committee with a clear picture of (i) how its decisions with respect to one element of compensation affect the total compensation package, (ii) how current compensation relates to compensation in previous years, and (iii) the total amount executive officers would receive, including the value of equity awards, under various termination scenarios. The Committee also reviews the total value of each executive officer's proposed salary, target bonus and grant date value of equity awards for the year compared to the median total compensation of individuals in similar positions as described above. Reviewing this information allows the Committee to make an overall assessment of the reasonableness of the total compensation that the company is providing to its executive officers.

As part of this review, the Committee also considers internal pay equity, both in terms of the total compensation of each executive officer as compared to the CEO, and within the officer group as compared to each other, considering individual responsibilities and experience levels. The Committee believes the executive compensation program should be internally consistent and equitable in order for it to achieve the objectives outlined in this **CD&A**.

*Compensation Program Risk Assessment*

The Compensation Committee annually reviews the structure of the company's compensation program in light of the key business risks as identified by the company's enterprise-wide risk assessment conducted annually by management and reviewed with the Board. In its annual review, the Committee considered how the elements of the compensation program encourage or discourage certain risk-taking behaviors. Based on the Committee's review of the compensation program in the context of the company's risk assessment, the Compensation Committee determined that the compensation program provides appropriate incentives and does not encourage executives to take excessive business risks.

**Components of the 2015 Executive Compensation Program**

The table below summarizes the elements of our executive compensation program, which are described in more detail in the following sections. Note that the description of the long-term incentive program in the table below is based on the terms of that program when the shares were granted in early 2015 and does not reflect the terms of the Merger Agreement, and the impact of the terms of that agreement if the transaction is closed. For a description of the potential impact of that agreement on the terms of the long-term incentive awards, please see the **Long-Term Incentive Awards** section below.

| | |
|---|---|
| **Base Salary** | Fixed amount of cash compensation. |
| **Annual Incentive Awards** | Annual cash incentive based on the achievement of quantitative corporate financial goals (80%) and qualitative individual business plan goals (20%). |
| **Long-Term Incentive Awards**<br>(See the **Long-Term Incentive Awards** section below for a description of the impact of the terms of the Merger Agreement with respect to these awards) | Restricted stock: 70% performance shares; 30% time-vested shares.<br>Three year vesting period – shares are forfeited upon voluntary departure from the company or termination with cause within this period. |
| ▪ **Performance-Based Restricted Stock (or "performance shares")** | Vests after three years based on earnings per share targets and total shareholder return compared to other companies in our industry. |
| ▪ **Time-Vested Restricted Stock** | Vests after three years if still employed at the company. |
| **Pension Plan** | Tax-qualified defined benefit pension plan available to all of our employees. |
| **Supplemental Retirement Plan** | Provides retirement benefits not available under the tax-qualified plan. |
| **Change-in-Control Agreements** | Provides severance payments if there is a change in control and executive is terminated without cause or terminates employment with good reason ("double-trigger"). |

**Base Salary**

*Summary*

The Compensation Committee considers potential adjustments to each named executive officer's base salary on an annual basis, taking into account written evaluations of each named executive officer's individual performance and responsibilities and the market data described above. The Committee believes that reviewing salary levels, market data and performance evaluations allows it to consider appropriate variables, such as individual officer's responsibilities and experience levels, and to tailor salaries accordingly, while remaining competitive with the marketplace.

*2015 Changes*

In early 2015, the Committee reviewed this information and took into consideration the relevant market data, the company's financial results from 2014 and forecast for 2015, and the individual considerations described above. The following table shows salary decisions for 2015 compared to 2014 for the continuing named executive officers:

| *Name* | *2014 Salary ($)* | *2015 Salary ($)* |
|---|---|---|
| John B. Ramil | 785,000 | 855,000 |
| Sandra W. Callahan | 475,000 | 489,250 |
| Gordon L. Gillette | 546,000 | 546,000 |
| Charles A. Attal III | 380,000 | 391,400 |
| Phil L. Barringer | 332,000 | 380,000 |

**Annual Incentive Awards**

The annual incentive awards paid for 2015 were based on a target award percentage and the level of achievement of the performance goals established for each named executive officer at the beginning of 2015, as described below.

*2015 Target Award Levels*

At the beginning of the year, the Compensation Committee set a target award (determined as a percentage of base salary) for the CEO and recommended a target award for each of the other named executive officers. The Committee established the target awards by reviewing the market data described under *Compensation Review Process* above, and based on the median total compensation for each position, selecting a target award that was designed to provide a competitive total cash opportunity consistent with the total target compensation amount determined for each executive officer. In setting the target award, the Compensation Committee also considered the portion of compensation "at risk" and whether this portion was reflective of the level of that officer's accountability for contributing to financial results and the degree of influence that officer would have over results and our success compared to other companies in our industry. The annual incentive target award percentages and amounts for the continuing named executive officers are shown below.

| *Name* | *2015 Annual Incentive Target Award (% of Salary)* | | *2015 Annual Incentive Target Award Amount* |
|---|---|---|---|
| John B. Ramil | 100% | $ | 855,000 |
| Sandra W. Callahan | 70% | $ | 342,475 |
| Gordon L. Gillette | 70% | $ | 382,200 |
| Charles A. Attal III | 60% | $ | 234,840 |
| Phil L. Barringer | 55% | $ | 209,000 |

*2015 Performance Metrics, Targets and Results*

*Financial Goals*

Our annual incentive plan provides for financial and/or operational effectiveness goals to be set each year for the plan participants. The Board set threshold, target and maximum goals for the income goals and capital expenditure goals as shown in the table below. The target goals were based on the relevant income and capital expenditure targets contained in the company's 2015 business plan, and were consistent with the earnings guidance given for the year. Threshold performance represents the minimum performance that warrants incentive recognition for that particular goal (paid at 50% of the target award level), and maximum performance represents extraordinary performance measured against target (capped at 150% of the target award level for financial goals). These goals are designed to recognize exceptional performance for the year at above the 100% level, while only providing a payout when performance meets or exceeds the threshold. If TECO Energy's threshold income goal is not achieved, then no incentive awards are paid to any officer, including the operating company officers.

TECO Energy officers' goals were based on achievement of TECO Energy financial performance targets, while Mr. Gillette's goals were based primarily on the performance of the company's Florida operations, over which he has direct responsibility, with a smaller percentage tied to overall TECO Energy performance.

Below are definitions for each of the goals used for the 2015 Annual Incentive Plan:

- Non-GAAP Results Goals: Income from continuing operations before charges and gains, calculated on the same basis as the results we refer to in communications with investors as our "non-GAAP results."
- Capital Expenditure Goals: This goal focuses on each company's net investment in operating assets for the year and its use of available capital in relation to the Board-approved capital investment plan for that year. It is calculated based on capital expenditures and disbursements for the year, less allowance for funds used during construction and proceeds from the sale of property and equipment.
- Individual Business Plan Goals: Individual goals for each officer designed to help the company achieve its overall business plan goals (each named executive officer's individual goals are described below).

The 2015 annual incentive goals and financial goal results are shown below.

| | *Relative Weightings* | | *2015 Financial Performance Goals (millions)* | | | | | |
|---|---|---|---|---|---|---|---|---|
| *Performance Measure* | *TECO Energy Officer %* | *Tampa Electric Co. President %* | *Threshold (50% Payout)* | | *Target (100% Payout)* | | *Maximum (150% Payout)* | |
| TECO Energy Non-GAAP Results Goal | 60% | 15% | $ | 229.4 | $ | 254.9 | $ | 262.7 |
| TECO Energy Capital Expenditure Goal | 20% | 5% | $ | (806.9) | | ($716.4) to ($750.6) | $ | (660.2) |
| Florida Operations Non-GAAP Results Goal | 0% | 45% | $ | 251.7 | $ | 279.7 | $ | 286.3 |
| Florida Operations Capital Expenditure Goal | 0% | 15% | $ | (741.7) | | ($657.2) to ($691.4) | $ | (606.9) |
| Individual Business Plan Goals | 20% | 20% | Goals described below; Level of achievement can range from 0% to 200% | | | | | |

*2015 Financial Goal Results*

| *Performance Measure* | *Target (millions)* | *2015 Results[(1)] (millions)* | *Achievement Percentage* |
|---|---|---|---|
| TECO Energy Non-GAAP Results Goal | $ 254.9 | $ 256.2 | 108.3% |
| TECO Energy Capital Expenditure Goal | ($716.4) to ($750.6) | ($739.1) | 100.0% |
| Florida Operations Non-GAAP Results Goal | $ 279.7 | $ 280.2 | 103.8% |
| Florida Operations Capital Expenditure Goal | ($657.2) to ($691.4) | ($684.8) | 100.0% |

(1) The table entitled **2015 Reconciliation of GAAP Net Income to Non-GAAP Results** in the **Results Summary** section of the **MD&A** shows how the results goal achievements are reconciled to GAAP net income.

*Individual Goals*

Our annual incentive plan also provides for each executive officer to have individual qualitative goals that are designed to help the company achieve its overall business plan goals. At the beginning of the year, each executive officer (other than the CEO) worked with the CEO to develop such goals. These individual goals were then presented to the Compensation Committee for review and recommendation to the company's Board of Directors for approval. The CEO's individual goals were reviewed by and discussed with the Chairman of the Board and then presented to the Compensation Committee for review and approval. The level of achievement of the individual business plan goals is a qualitative determination made by the Compensation Committee after reviewing a performance evaluation of each executive officer with respect to each specific goal, which are first reviewed by the CEO and then presented to the Compensation Committee for its evaluation. The Committee recommends individual performance achievement percentages for Board approval for the named executive officers after this evaluation. Individual performance for the CEO is based on the Compensation Committee's qualitative assessment of his performance, which it makes after reviewing the recommendation of the Chairman of the Board.

Individual business plan goals and achievement percentages for the respective continuing named executive officers are described below:

| | *2015 Individual Business Plan Goals* | *2015 Achievement* |
|---|---|---|
| John B. Ramil | Leadership of strategic growth initiatives to help achieve return on equity and earnings per share growth goals; close on the sale of TECO Coal; service and quality initiatives; community relationships; integration of NMGC; values initiatives; and technology and business process strategies | 200% |
| Sandra W. Callahan | Financial leadership in growth initiatives to help achieve return on equity and earnings per share growth goals; close on the sale of TECO Coal; financial community communications; community relationships; integration of NMGC; values initiatives; and technology and business process strategies | 150% |
| Gordon L. Gillette | Leadership of business plan execution and utility-related initiatives to help achieve return on equity and earnings per share growth goals; close on the sale of TECO Coal; service and quality initiatives; customer relations and communications initiatives, reliability and safety; community relationships; integration of NMGC; values initiatives; and technology and business process strategies | 125% |
| Charles A. Attal III | Leadership in supporting growth and expense control initiatives to help achieve return on equity and earnings per share growth goals; close on the sale of TECO Coal; cost-effective legal services supporting significant transactions, litigation, and emerging industry pressures; policy strategies and community relationships; integration of NMGC; values initiatives; and technology and business process strategies | 200% |
| Phil L. Barringer | Leadership in supporting growth and expense control initiatives to help achieve return on equity and earnings per share growth goals; close on the sale of TECO Coal; identified business processes and corporate services initiatives; policy strategies and community relationships; integration of NMGC; values initiatives; and technology and business process strategies | 175% |

*2015 Annual Incentive Plan Payouts*

The 2015 awards to the executive officers under the annual incentive program, which are shown in the table below, were based on the achievement of the corporate financial goals and the individual business plan goals described above. The Committee has discretion to increase or decrease awards if it determines that the plan formula would unduly reward or penalize management. The Committee did not make any adjustments to the 2015 awards calculated pursuant to the plan's formula. The total amounts awarded under the 2015 annual incentive program are also shown under the "Non-Equity Incentive Plan Compensation" column in the **2015 Summary Compensation Table**.

*2015 Annual Incentive Award Payouts*

| *Name* | *2015 Annual Incentive Target Award Amount* | *2015 Annual Incentive Award Paid* | *2015 Award as Percentage of Target Award* |
|---|---|---|---|
| John B. Ramil | $ 855,000 | $ 1,068,750 | 125% |
| Sandra W. Callahan | $ 342,475 | $ 393,846 | 115% |
| Gordon L. Gillette | $ 382,200 | $ 412,600 | 108% |
| Charles A. Attal III | $ 234,840 | $ 293,550 | 125% |
| Phil L. Barringer | $ 209,000 | $ 250,800 | 120% |

**Long-Term Incentive Awards**

*Mix of Types of Awards*

The long-term incentive component of our compensation program consists of equity-based grants, which in 2015 were in the form of 70% performance shares and 30% time-vested restricted stock. This mix was designed to tie the largest percentage of the equity incentives directly to our performance relative to companies in our industry, with the value of the remaining incentives also being tied to stock price and continued service.

The Committee does not grant stock options because it previously determined that performance shares and time-vested restricted stock grants more closely serve the goals of tying compensation levels to company performance and promoting long-term retention of executives. Also, by granting such stock awards instead of stock options, fewer shares are used to deliver the same value to employees, resulting in less dilution to shareholders. The grant date of the restricted stock awards is the same day that the Committee approves the grants, which since 2013 has occurred at the Committee's first quarterly meeting of the year.

*Performance Share Formula*

The payout of the performance shares granted in 2015 is based on a combination of meeting a cumulative earnings per share goal and relative total shareholder return for the three-year performance period of Jan. 1, 2015 to Dec. 31, 2017. (See *Treatment of Outstanding Equity Awards Under the Merger Agreement* below for a description of the impact of that agreement on these awards.)

Below are the cumulative earnings per share goals for the 2015 performance share grants and the corresponding payout for meeting those goals. Cumulative EPS is calculated by adding the company's EPS for each calendar year in the performance period. The calculation of earnings on a per share basis may be adjusted at the discretion of the Committee to exclude the effect of certain events that impact such calculation as specified in the performance share grant agreement and permitted by the company's 2010 Equity Incentive Plan. Payouts are prorated for performance between the minimum and maximum goals.

| | |
|---|---|
| Cumulative EPS of less than $3.280 | 0% payout |
| Cumulative EPS of $3.280 | 50% payout |
| Cumulative EPS of $3.437 | 100% payout |
| Cumulative EPS of $3.543 or more | 150% payout |

In addition, if the company's TSR is in the top 25 percent of the peer group described below, an additional 33% of shares would be awarded (the "TSR bonus multiplier"), with a potential maximum payout of 200% if the maximum earnings per share goal is achieved and the company is the top 25% of the peer group for the three-year period beginning Jan. 1, 2015 and ending Dec. 31, 2017.

The TSR bonus multiplier is based on our TSR compared to the companies listed in the Dow Jones Conventional Electricity and Multi Utility subsectors of its Utilities index.

These grants were designed to directly tie a portion of compensation to achieving our earnings per growth strategy, while retaining a long-term performance measure relative to other companies in our industry. The three-year performance period was also designed to aid in the retention of our executives.

TSR is calculated by dividing (1) the sum of (a) the difference between the share price at the end and beginning of the three-year performance period, and (b) the amount of dividends with respect to the three-year performance period, assuming dividend reinvestment, by (2) the closing share price at the beginning of the three-year performance period, with the share price in each case being determined by using the average closing price during the 20 trading days ending on the date of determination. Share price is equitably adjusted for stock splits and other similar corporate actions affecting the stock.

*Equity Vesting Schedules*

At the end of the three-year performance period described above, the performance results are calculated, and either (i) the performance shares are forfeited or (ii) the shares vest and, potentially, additional shares are granted. The time-vested restricted stock vests in a single installment three years from the date of grant. At the time of vesting of either the performance shares or time-vested restricted stock, the holder becomes the holder of shares of non-restricted common stock with the same terms as our common stock. Beginning with the equity grants in 2014, the terms of the time-vested restricted awards granted to executive officers also provide that shares under such awards, which would otherwise vest in any year strictly upon the passage of time, will not vest unless and until the Compensation Committee certifies that the financial goal designated in advance by the Compensation Committee has been achieved.

If employment is terminated during the three-year period without cause by the company or through a normal retirement by the employee (as described below in the *Pension Benefits – Supplemental Plan* section), a prorated amount of shares would vest based on the amount of time employed during the three-year period, and in the case of the performance shares, based on the calculation of the performance measurement as specified in the grant document. All shares are forfeited if employment is terminated for cause by the company or is terminated by the employee voluntarily (except in the case of a normal retirement).

The agreements governing all outstanding time-vested restricted stock and performance share awards are “double-trigger” arrangements, such that vesting of the shares would only be accelerated following a change in control if the grantee is also terminated without cause or terminates employment with good reason. (The payout of the performance shares under those circumstances would still be based on the applicable performance calculation.) As described below, the Merger Agreement with Emera provides how outstanding awards would be treated upon the closing of that transaction.

*Determination of 2015 Long-Term Incentive Awards*

Long-term incentive awards were granted at levels that provided each executive officer with total target compensation that was in line with the amounts developed for each officer using the data and process described under *Compensation Review Process* above.

The Committee also considered the total number of shares subject to equity incentive grants in relation to the total number of our outstanding shares, and reviewed information with respect to the estimated total and annual accounting expense associated with the equity incentive grants.

Using this information, the Committee made equity incentive grants at a level designed to continue to attract, retain and motivate our executives, control dilution and maintain reasonable annual accounting expense.

The 2015 target long-term equity incentive award opportunity for each named executive officer whose awards are still outstanding is shown below based on the grant date fair value of the shares on the date of grant (calculated under applicable accounting rules):

| | *Performance Shares (Target Amount)* | | *Time-Based Restricted Stock* | | |
|---|---|---|---|---|---|
| *Name* | *# of shares* | *Grant Date Fair Value ($)* | *# of shares* | *Grant Date Fair Value ($)* | *Total Target LTI Opportunity ($)* |
| John B. Ramil | 88,792 | 2,152,247 | 38,054 | 825,011 | 2,977,258 |
| Sandra W. Callahan | 22,924 | 555,659 | 9,825 | 213,006 | 768,665 |
| Gordon L. Gillette | 16,144 | 391,318 | 6,919 | 150,004 | 541,322 |
| Charles A. Attal III | 16,144 | 391,318 | 6,919 | 150,004 | 541,322 |
| Phil L. Barringer | 16,144 | 391,318 | 6,919 | 150,004 | 541,322 |

*Payment of Dividends*

Dividends are not paid on unvested performance-based awards. (Dividends on such awards are accumulated and paid on the amount of the award that vests and are forfeited for any shares that do not vest.) Holders of time-vested restricted stock receive the same dividends as holders of other shares of our common stock.

*Treatment of Outstanding Equity Awards Under the Merger Agreement*

Pursuant to the Merger Agreement, at the closing of the Merger, each outstanding performance share and share of time-vested restricted stock will vest and will be cancelled and converted into the right to receive a lump-sum cash payment (paid as promptly as practicable following closing, less any applicable withholding) equal to the per-share merger consideration ($27.55), plus any accrued dividends. With respect to the performance shares, the applicable performance goals and bonus multipliers will be deemed achieved at the maximum level as of immediately prior to the closing.

**Retirement and Other Benefits**

*Supplemental Executive Retirement Plan*

Our named executive officers participate in a supplemental retirement plan that provides benefits at a level not available under the tax-qualified plan and is meant as an additional aid in attracting and retaining officers in key positions.

*Change-in-Control Agreements*

We have change-in-control agreements with each of our named executive officers. These agreements are all “double-trigger” arrangements, meaning that payments are only made if there is a change in control of the company or one is being contemplated and the officer’s employment is terminated without cause or the officer terminates employment for good reason. Since 2010, new change-in-control agreements have not included an excise tax gross-up. The agreements for our named executive officers are discussed in greater detail under the **Post-Termination Benefits** section. The Committee periodically reviews the level of benefits in these agreements to ensure they remain reasonable, given practices in the market. We believe that providing these agreements helps increase our ability to attract, retain and motivate highly qualified management personnel and encourage their continued dedication without distraction from concerns over job security relating to a change in control of the company.

*Minimal “Other Compensation”*

In 2015, the “Other Compensation” reported in the **2015 Summary Compensation Table** for each continuing named executive officer was less than 1% of total compensation for the year. These amounts were for company matches to our 401(k) plan, a benefit that is available to all of our employees that contribute to such plan, and an annual premium of $312 for a $100,000 supplemental life insurance policy for each of our officers and key employees.

**Agreements with Former Executive Officer**

Pursuant to Clark Taylor’s change-in-control agreement with TECO Coal, payment under which was triggered by the closing of the sale of that company in September 2015, he received a payment equal to three times the sum of (a) his annual salary in effect prior to the sale of TECO Coal and (b) his highest annual incentive target award in effect during the three-year period prior to the date of termination of employment. The agreement also provided for participation available in our life, disability, accident and health insurance plans for a three-year period, except to the extent these benefits are provided by a subsequent employer. The agreement included a release of any claims against the company. Mr. Taylor also received a lump sum payment of $489,600 pursuant to the terms of a retention agreement entered into in connection with sale process.

**Other Compensation-Related Policies**

*Share Ownership Guidelines*

We have share ownership guidelines of five times base salary for the CEO and three times base salary for the other executive officers. The guidelines require that each executive hold at least 50% of net, after-tax shares obtained through the vesting or exercise of long-term incentive awards until the share ownership guidelines are met. Unvested performance shares do not count for the purposes of this guideline. The Committee reviews share ownership on an annual basis to ensure continued compliance with these guidelines and determined that, as of Dec. 31, 2015, there were no violations of this policy.

*Hedging and Pledging Policies*

Our hedging policy prohibits hedging transactions such as zero-cost collars and forward sale contracts, which would allow the person to own the covered securities without the full risks and rewards of ownership, potentially causing that person’s objectives to diverge from that of our other shareholders. Our pledging policy prohibits officers and directors from pledging stock in our company.

*Claw-Back Policy*

Our Claw-Back Policy applies to annual incentive awards in the case of any financial restatements if a lower payment would have been made to the officer based upon the restated financial results, regardless of the cause of the restatement (whether or not due to the fraud or fault of the officer). The policy applies to proceeds from stock and option sales if an officer engaged in an act of embezzlement, fraud or breach of fiduciary duty that contributed to the need to restate the company’s financials. The full text of the policy is included in the company’s Corporate Governance Guidelines available in the Corporate Governance section of the Investor Relations page of our website, www.tecoenergy.com.

**Tax Considerations**

Section 162(m) of the Internal Revenue Code limits the federal income tax deductibility of certain compensation to $1 million per year for the CEO and the other three highest paid named executive officers (other than the CFO) who were employed at year-end. However, if certain conditions are satisfied, “performance-based” compensation may be excluded from this limitation on deductibility.

The annual incentive awards and stock awards granted in 2015 were designed to meet the definition of "performance-based" compensation in the Code. The Committee seeks to maintain the deductibility of compensation for the company; however, its primary objective in making compensation decisions is to provide compensation that best meets the goals of the compensation program. Therefore, while the tax impact of any compensation arrangement is one factor to be considered, this impact is evaluated in light of the objectives of the compensation program described above, and compensation may be awarded that is not fully deductible if necessary to meet these objectives.

The following tables give information regarding the compensation provided to our Chief Executive Officer, Chief Financial Officer, and the three other most highly compensated executive officers who were employed by the company as of Dec. 31, 2015. In addition, information is included on one former executive officer (Clark Taylor, formerly President of TECO Coal) whose total compensation would have made him one of the three other most highly compensated executive officers for 2015. (Mr. Taylor did not receive any equity or non-equity incentive plan-based awards in 2015 and had no outstanding equity awards at 2015 fiscal year-end, and is therefore not listed in those tables.)

**2015 Summary Compensation Table**

| *Name and Principal Position* | *Year* | *Salary ($)* | *Stock Awards[(1)] ($)* | *Non-Equity Incentive Plan Compensa-tion ($)* | *Change in Pension Value and Nonqualified Deferred Compensation Earnings [(2)] ($)* | *All Other Compen-sation [(3)]($)* | *Total ($)* |
|---|---|---|---|---|---|---|---|
| John B. Ramil | 2015 | 855,000 | 2,977,258 | 1,068,750 | 1,626,432 | 11,919 | 6,539,359 |
| President and | 2014 | 785,000 | 2,345,728 | 867,456 | 1,327,441 | 12,948 | 5,338,573 |
| Chief Executive Officer | 2013 | 765,000 | 2,602,789 | 825,710 | 669,711 | 10,051 | 4,873,261 |
| Sandra W. Callahan | 2015 | 489,250 | 768,665 | 393,846 | 1,042,411 | 11,919 | 2,706,091 |
| Senior Vice President – Finance | 2014 | 475,000 | 586,435 | 367,426 | 740,164 | 12,948 | 2,181,973 |
| and Accounting and Chief Financial Officer | 2013 | 460,000 | 602,500 | 321,981 | 591,624 | 10,051 | 1,986,156 |
| Gordon L. Gillette | 2015 | 546,000 | 541,322 | 412,600 | 299,759 | 11,919 | 1,811,600 |
| President, Tampa | 2014 | 546,000 | 651,595 | 382,200 | 665,850 | 12,948 | 2,258,593 |
| Electric Company | 2013 | 535,000 | 655,531 | 412,356 | 0 [(4)] | 10,051 | 1,612,938 |
| Charles A. Attal III | 2015 | 391,400 | 541,322 | 293,550 | 410,175 | 11,919 | 1,648,366 |
| Senior Vice President – General Counsel | 2014 | 380,000 | 417,017 | 251,949 | 414,777 | 12,948 | 1,476,691 |
| and Chief Legal Officer and Chief Ethics and Compliance Officer | 2013 | 366,000 | 433,810 | 234,996 | 181,792 | 10,051 | 1,226,649 |
| Phil L. Barringer | 2015 | 380,000 | 541,322 | 250,800 | 649,293 | 11,919 | 1,833,334 |
| Senior Vice President Corporate Services and Chief Human Resources Officer | 2014 | 332,000 | 364,881 | 201,780 | 494,985 | 12,948 | 1,406,594 |
| | 2013 | 320,000 | 385,595 | 188,515 | 283,353 | 10,051 | 1,187,514 |
| Clark Taylor, formerly President, TECO Coal[(5)] | 2015 | 249,508 | 0 | 0 | 556,037 | 2,051,811 [(6)] | 2,857,356 |

(1) The amounts reported for stock awards reflect the aggregate grant date fair value based on the "target awards," computed in accordance with FASB ASC Topic 718. See **Note 9 to the TECO Energy Consolidated Financial Statements** for a discussion of the assumptions made in valuations of stock awards. As noted in the description of "Long-Term Incentive Awards" above, 70% of the value of stock awards are provided in the form of performance shares, which for the years shown in the table above are shares of restricted stock that vest or are forfeited depending on the satisfaction of performance conditions based on TSR and EPS over a three-year period. Therefore, depending on the company's stock performance and EPS, up to 70% of the shares, the value of which are reported under "Stock Awards," may ultimately be forfeited, or an additional 50% of the shares granted in 2013 and 2014, or an additional 100% of the shares granted in 2015, may be earned. The grant date fair values of such maximum potential awards for 2015 were as follows: $4,304,494 for Mr. Ramil; $1,111,319 for Ms. Callahan; and $782,635 for Messrs. Gillette, Attal and Barringer.

(2) This column shows the change in the actuarial present value of the benefits that would be provided under our tax-qualified defined benefit plan and our supplemental retirement plan. This value is calculated based on variables such as average earnings and years of service, and therefore a larger increase in value may be attributable, for example, to an increase in pay, year over year. Other factors affecting the present value include interest rates and the age of the officer. See **Pension Benefits** below for a description of our retirement plans. The changes in value shown above are attributable to both plans, with the change in value attributed only to the tax-qualified plan in: 2015, 2014, and 2013, respectively, of: $54,656, $195,427, and $(6,887), for Mr. Ramil; $20,047, $159,168, and $(25,441), for Mr. Gillette; $105,718, $211,904, and $30,302, for Ms. Callahan; $25,750, $19,460, and $20,160, for Mr. Attal; $88,426, $212,211, and $212,211, for Mr. Barringer; and $115,522 for Mr. Taylor in 2015.

The balance in each case represents the change in value of the supplemental plan. The company does not maintain a non-qualified deferred compensation plan for employees.

(3) The amounts reported in this column for 2015 include for each named executive officer $312 in premiums paid by us for supplemental life insurance and $11,130 of employer contributions under the TECO Energy Group Retirement Savings Plan.

(4) Mr. Gillette's pension value decreased by $102,163 in 2013, due primarily to the impact of a higher discount rate than in the previous year.

(5) Mr. Taylor was not a named executive officer before 2015. His employment with the company terminated in September 2015 upon the sale of TECO Coal.

(6) All Other Compensation for Mr. Taylor included the payments as described under the **Agreements with Former Executive Officer** above.

**Grants of Plan-Based Awards for the 2015 Fiscal Year**

| | | *Estimated Possible Payouts Under Non-Equity Incentive Plan Awards (1),(2)* | | | *Estimated Future Payouts Under Equity Incentive Plan Awards (2), (3) (performance shares)* | | | *All Other Stock Awards: Number of Shares of Stock or Units (4)* | *Grant Date Fair Value of Stock and Option Awards (5)* |
|---|---|---|---|---|---|---|---|---|---|
| *Name/Award Type* | *Grant Date* | *Threshold ($)* | *Target ($)* | *Maximum ($)* | *Threshold (#)* | *Target (#)* | *Maximum (#)* | *(#)* | *($)* |
| John B. Ramil | | | | | | | | | |
| annual incentive plan | 2/4/15 | 427,500 | 855,000 | 1,282,500 | | | | | |
| performance shares | 2/4/15 | | | | 22,198 | 88,792 | 177,584 | | 2,152,247 |
| time-vested restricted stock | 2/4/15 | | | | | | | 38,054 | 825,011 |
| Sandra W. Callahan | | | | | | | | | |
| annual incentive plan | 2/4/15 | 171,238 | 342,475 | 513,713 | | | | | |
| performance shares | 2/4/15 | | | | 5,731 | 22,924 | 45,848 | | 555,659 |
| time-vested restricted stock | 2/4/15 | | | | | | | 9,825 | 213,006 |
| Gordon L. Gillette | | | | | | | | | |
| annual incentive plan | 2/4/15 | 191,100 | 382,200 | 573,300 | | | | | |
| performance shares | 2/4/15 | | | | 4,036 | 16,144 | 32,288 | | 391,318 |
| time-vested restricted stock | 2/4/15 | | | | | | | 6,919 | 150,004 |
| Charles A. Attal III | | | | | | | | | |
| annual incentive plan | 2/4/15 | 117,420 | 234,840 | 352,260 | | | | | |
| performance shares | 2/4/15 | | | | 4,036 | 16,144 | 32,288 | | 391,318 |
| time-vested restricted stock | 2/4/15 | | | | | | | 6,919 | 150,004 |
| Phil L. Barringer | | | | | | | | | |
| annual incentive plan | 2/4/15 | 104,500 | 209,000 | 313,500 | | | | | |
| performance shares | 2/4/15 | | | | 4,036 | 16,144 | 32,288 | | 391,318 |
| time-vested restricted stock | 2/4/15 | | | | | | | 6,919 | 150,004 |

(1) The amount that was received in 2015 under the annual incentive plan is reported for each officer in the "Non-Equity Incentive Plan Compensation" column of the **2015 Summary Compensation Table**.

(2) See the descriptions in the **CD&A** section above regarding how the threshold, target and maximum awards are determined.

(3) Amounts in these columns represent performance share grants made under our 2010 Equity Incentive Plan.

(4) Amounts in this column represent time-vested restricted stock grants made under our 2010 Equity Incentive Plan.

(5) Amounts in this column are based on the grant date fair value based on the target number of performance shares granted and management's expected achievement of the EPS goal, plus the expected outcome of the TSR bonus multiplier as of the date of grant based on a relative total shareholder return model using a Monte-Carlo simulation, in accordance with FASB ASC Topic 718.

The amounts payable under the annual incentive plan are determined based on the achievement of certain corporate financial and individual qualitative goals described in the **CD&A** section above. The threshold, target and maximum amounts that could have been paid under the 2015 annual incentive plan are shown in the table above in the "Estimated Possible Payout Under Non-Equity Incentive Plan Awards."

Information regarding the formula used to determine the payout of the performance shares, equity vesting schedules and the payment of dividends is included in the **CD&A** section above under corresponding headings.

**Outstanding Equity Awards at 2015 Fiscal Year-End**

| | *Option Awards* | | | *Stock Awards* | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| *Name* | *Number of Securities Underlying Unexercised Options Exercisable (#)* | *Option Exercise Price ($)* | *Option Expiration Date* | *Number of Shares or Units of Stock That Have Not Vested (#)*[1] | | *Market Value of Shares or Units of Stock That Have Not Vested ($)*[1] | *Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)*[2] | | *Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)*[2] |
| John B. Ramil | | | | | | | | | |
| | | | | 3,900 | 3 | 103,935 | 106,299 | 4 | 2,832,868 |
| | | | | 45,557 | 5 | 1,214,094 | 112,971 | 6 | 3,010,677 |
| | | | | 48,416 | 7 | 1,290,286 | 88,792 | 8 | 2,366,307 |
| | | | | 38,054 | 9 | 1,014,139 | | | |
| Sandra W. Callahan | | | | | | | | | |
| | | | | 10,546 | 5 | 281,051 | 24,606 | 4 | 655,750 |
| | | | | 12,104 | 7 | 322,572 | 28,243 | 6 | 752,676 |
| | | | | 9,825 | 9 | 261,836 | 22,924 | 8 | 610,925 |
| Gordon L. Gillette | | | | | | | | | |
| | | | | 11,474 | 5 | 305,782 | 26,772 | 4 | 713,474 |
| | | | | 13,449 | 7 | 358,416 | 31,381 | 6 | 836,304 |
| | | | | 6,919 | 9 | 184,391 | 16,144 | 8 | 430,238 |
| Charles A. Attal III | | | | | | | | | |
| | | | | 7,593 | 5 | 202,353 | 17,717 | 4 | 472,158 |
| | | | | 8,607 | 7 | 229,377 | 20,084 | 6 | 535,239 |
| | | | | 6,919 | 9 | 184,391 | 16,144 | 8 | 430,238 |
| Phil L. Barringer | | | | | | | | | |
| | 6,650 | 16.2950 | 04/25/2016 | 6,749 | 5 | 179,861 | 15,748 | 4 | 419,684 |
| | | | | 7,531 | 7 | 200,701 | 17,573 | 6 | 468,320 |
| | | | | 6,919 | 9 | 184,391 | 16,144 | 8 | 430,238 |

(1) Shares shown under these columns are time-vested restricted shares that vest three years following the date of grant on the dates shown in footnotes 5, 7 and 9 below, or vest at normal retirement age, as shown in footnote 3, below.

(2) Shares shown under these columns are the target amount of performance shares that vest only if certain performance criteria are met at the end of a three-year performance period; the performance periods for such shares end on the dates shown in footnotes 4, 6 and 8, below. The market value shown assumes that the shares are paid out at target and is based on the closing stock price on Dec. 31, 2015 of $26.65.

(3) These shares, which were granted to Mr. Ramil in 1997, vest at normal retirement age, as defined in the TECO Energy Group Retirement Plan, or upon the closing of the transaction contemplated by the Merger Agreement.

(4) Vest upon the satisfaction of performance criteria following the end of the performance period for such shares, Dec. 31, 2015, or upon the closing of the transaction contemplated by the Merger Agreement.

(5) Vest in one installment on Jan. 30, 2016, three years from the date of grant, or upon the closing of the transaction contemplated by the Merger Agreement.

(6) Vest upon the satisfaction of performance criteria following the end of the performance period for such shares, Dec. 31, 2016.

(7) Vest in one installment on Jan. 29, 2017, three years from the date of grant, or upon the closing of the transaction contemplated by the Merger Agreement.

(8) Vest upon the satisfaction of performance criteria following the end of the performance period for such shares, Dec. 31, 2017, or upon the closing of the transaction contemplated by the Merger Agreement.

(9) Vest in one installment on Feb. 4, 2018, three years from the date of grant, or upon the closing of the transaction contemplated by the Merger Agreement.

### Option Exercises and Stock Vested in the 2015 Fiscal Year

| | *Option Awards* | | *Stock Awards* | |
|---|---|---|---|---|
| *Name* | *Number of Shares Acquired on Exercise (#)* | *Value Realized on Exercise ($)* | *Number of Shares Acquired on Vesting [1] (#)* | *Value Realized on Vesting [2] ($)* |
| John B. Ramil | 72,450 | 302,645 | 48,108 | 911,647 |
| Sandra W. Callahan | 6,383 | 53,489 | 10,584 | 200,567 |
| Gordon L. Gillette | — | — | 12,508 | 237,027 |
| Charles A. Attal III | 8,900 | 92,054 | 9,333 | 176,860 |
| Phil L. Barringer | — | — | 6,735 | 127,628 |
| Clark Taylor | 22,450 | 145,425 | 40,082 | 1,021,484 |

(1) The shares acquired on vesting were time-vested restricted stock. (The performance shares due for vesting in 2015 were forfeited.)

(2) The value realized on vesting is the market value of the underlying shares on the vesting date, computed based on the closing price of the stock on the day prior to vesting.

### Pension Benefits

The following table shows the present values of accumulated benefits payable under our pension plan arrangements for the named executive officers as of Dec. 31, 2015, the most recent pension plan measurement date for financial reporting purposes. The "qualified plan" refers to the TECO Energy Group Retirement Plan, our tax-qualified defined benefit plan that is available to our U.S. employees. The "supplemental plan" refers to the TECO Energy Group Supplemental Executive Retirement Plan, a supplemental executive retirement plan described in the **CD&A** under the **Retirement and Other Benefits** section.

| ***Name*** | ***Plan Name*** | ***Number of Years Credited Service [1] (#)*** | ***Present Value of Accumulated Benefit ($)*** | ***Payments During Last Fiscal Year ($)*** |
|---|---|---|---|---|
| John B. Ramil | qualified plan | 40 | 1,062,847 | — |
| | supplemental plan | | 10,371,843 | |
| Sandra W. Callahan | qualified plan | 28 | 1,265,966 | — |
| | supplemental plan | | 5,183,992 | |
| Gordon L. Gillette | qualified plan | 35 | 698,178 | — |
| | supplemental plan | | 4,250,261 | |
| Charles A. Attal III | qualified plan | 14 | 201,450 | — |
| | supplemental plan | | 2,064,850 | |
| Phil L. Barringer | qualified plan | 31 | 1,211,400 | — |
| | supplemental plan | | 2,851,623 | |
| Clark Taylor | qualified plan | 31 | 1,474,416 | 25,932 |
| | supplemental plan | | 2,121,310 | |

(1) The number of years of credited service is the same for both plans and is rounded to the nearest whole year.

*Qualified Plan*

Our employees, including executive officers, are eligible to participate in our tax-qualified defined benefit plan, and become 100% vested in the benefit they have accrued upon completion of three years of service or reaching the age of 65. All of our named executive officers are vested in this plan. Normal retirement age for the qualified plan is the same as the eligibility age for unreduced Social Security benefits. Under the terms of the qualified plan applicable to the named executive officers, the earliest age at which retirement benefits are available without reduction for age is three years before the normal retirement age.

The qualified plan's normal retirement payment and benefit formula is based on the employee's age, years of service and final average earnings. Benefits can be paid as an annuity or in a lump sum, at the election of the participant.

The present value of the accumulated benefit under the qualified plan in the table above was calculated assuming that participants retire at the earliest age at which retirement benefits are available without reduction for age, using the same assumptions the company used for pension plan measurement for 2015 financial statement reporting purposes with respect to the present value discount rate (4.685%), lump sum conversion rate (4.7% for Mr. Ramil, 4.9% for Mr. Gillette, 4.1% for Ms. Callahan, 4.8% for Mr. Attal, 4.5% for Mr. Barringer and 4.0% for Mr. Taylor), and form of payment and mortality assumptions.

*Supplemental Plan*

The normal retirement payment and benefit formula for the named executive officers who are participants in the supplemental plan is 3% times final average earnings times years of credited service, up to a maximum of 20 years (therefore, the maximum amount payable is 60% of final average earnings). Final average earnings are based on the greater of (a) the officer's final 36 months of earnings or (b) the officer's highest three consecutive calendar years of earnings out of the five calendar years preceding retirement. The plan was amended in 2007 to provide that the benefit formula for new participants is 2% times final average earnings times years of credited service, up to a maximum of 30 years; however, all of our named executive officers became participants in the plan prior to that change.

The earnings covered by the qualified plan and supplemental plan are the same as those reported as salary and non-equity incentive plan awards in the summary compensation table above. The pension benefits are computed as a straight-life annuity commencing at the officer's normal retirement age and are reduced by the officer's Social Security benefits. Benefits payable under the supplemental plan are also reduced by benefits payable under the qualified pension plan. Normal retirement age is 63 and two months for Mr. Ramil, 64 for Mr. Gillette, 63 for Ms. Callahan, 63 and 10 months for Mr. Attal, and 63 for Mr. Barringer. A reduced amount of benefits may be received upon retirement any time after age 55, as long as the officer has five years of service. If early retirement is elected, payment is based on actual years of service at early retirement using the formula described above, however, benefits are reduced by 5% for each year that payment begins before the normal retirement date.

Pursuant to the terms of the supplemental plan, if a change in control of the company occurs, an officer who had reached early retirement age would be eligible to receive the same benefit that would normally be payable for early retirement, except the minimum five years of service requirement would not apply. If a change in control occurs before an officer has reached early retirement age, the benefit payable would be based on length of service and final average earnings on the date of the change of control, reduced by an early retirement factor of at least 0.59, based on the number of years the change of control occurred before the participant's normal retirement age. Pursuant to the terms of the named executive officers' change-in-control severance agreements, if those agreements are triggered as described below, the officers would receive a cash payment equal to the actuarial equivalent of the additional retirement benefit that would have been earned under our retirement plans if employment had continued for three years following the date of termination.

The benefit payable under the supplemental plan is paid in the form of a lump sum only (not an annuity). The present value of the accumulated benefit for the supplemental plan shown in the table above was calculated by discounting the lump sum that would be payable at the officer's normal retirement age using a discount rate of 4.734%.

If the officer dies during employment before reaching normal retirement age, the officer's benefits under the supplemental and qualified plan are payable to the surviving spouse in a reduced amount. This death benefit is equal to 50% of the benefit that would have been payable to the officer based on the officer's service as if employment had continued until retirement age. The supplemental plan death benefit is payable in the form of a lump sum to the spouse minus benefits payable to the spouse under the qualified plan.

**Post-Termination Benefits**

*Change-in-Control Agreements*

We have change-in-control severance agreements with the named executive officers under which payments will be made under certain circumstances in connection with a change in control of TECO Energy. A change in control means in general an acquisition by any person of 30% or more of our common stock, a change in a majority of our directors, a merger or consolidation in which our shareholders have less than 50% of the voting power in the surviving entity, or a liquidation or sale of substantially all of our assets.

The change-in-control agreements are "double-trigger" arrangements that only provide for payment of the benefits described below if there is a change in control or one is contemplated and

- employment is terminated by us without cause (as defined below) or
- employment is terminated by the officer for good reason (as defined below).

If employment is terminated under those circumstances, after expiration of a six-month deferral period as may be required under Section 409A of the Internal Revenue Code, we will make or provide:

- a lump sum severance payment to the executive officer of three times his or her annual salary and highest target annual incentive award in effect at any time during the thirty-six months prior to the date of termination,
- a cash payment equal to the actuarial equivalent of the additional retirement benefit that would have been earned under our retirement plans if employment had continued for three years following the date of termination,
- company-paid life, disability, accident and health insurance plans for a three-year period, except to the extent these benefits are provided by a subsequent employer, and
- for Messrs. Ramil, Gillette and Attal (whose change-in-control severance agreements were put in place before 2010), a payment in compensation for any additional taxes that may be payable as a result the 20% excise tax imposed under Section

4999 of the Internal Revenue Code on the benefits received under the change-in-control severance agreements and any other benefits contingent on a change in control; however, such payment will only be made if the total payment due in connection with a change-in-control exceeds the amount at which an excise tax is first imposed by at least 10%. If the total payment due does not exceed by at least 10% the amount at which an excise tax is first imposed, the total payment will be reduced to the point that an excise tax would not be imposed. In 2010, the Compensation Committee determined not to provide excise tax gross-ups (described in the last bullet point above) in change-in-control agreements going forward. Accordingly, Ms. Callahan's and Mr. Barringer's change-in-control agreements (which were amended since that time) do not provide for an excise tax-gross up, but rather provide that benefits will be capped in those instances in which applying such cap would provide greater after-tax benefits after the application of Section 4999 of the Internal Revenue Code.

For the purposes of the change-in-control agreements, termination with "cause" is defined as termination resulting from the willful and continued failure to substantially perform job duties or willful engagement in conduct which is demonstrably and materially injurious to the company, monetarily or otherwise. Termination of employment for "good reason" is defined as termination by the officer following the assignment to the officer of any duties inconsistent (except in the nature of a promotion) with the position held immediately prior to the change in control or a substantial adverse alteration in the nature or status, responsibilities or the conditions of employment, a reduction in annual base salary, the company's requiring the officer to be based more than 50 miles from current job location, the failure by the company to pay compensation within seven days of the due date, the discontinuation without substitution of any material compensation or benefit plan or other benefits the officer participated in immediately prior to the change in control or reduction of those benefits, or the company's attempt to terminate the officer's employment in a manner not consistent with the terms of the agreement.

Under the terms of the change-in-control agreements, in the event employment is terminated in contemplation of or following a change in control, the officer would be entitled to receive his or her base salary through the termination date, and under the terms of our annual incentive plan, an incentive award equal to the target incentive amount for the year or the target incentive amount for the prior year (if greater), prorated for the number of days served in the year the termination occurred. Under the terms of the Merger Agreement, if the officer experiences an involuntary termination of employment on or within 30 days following the closing of the Merger or if the officer terminates his or her employment with good reason (as defined above) arising within 30 days following the closing of the Merger, the officer will receive a prorated bonus amount calculated at the maximum payout level.

The agreements require that the officer, subject to the terms of the agreement, remain our employee for one year following a potential change in control (unless an actual change in control occurs, as defined above). The agreements define potential change in control more broadly than an actual change in control to ensure that the company receives the benefit of the continued employment of the officer after such an event occurs. A "potential change in control" occurred when we entered into the Merger Agreement.

Other benefits may also be paid in connection with a change in control under the supplemental executive retirement plan (as described above under "Pension Benefits"). In addition, the Agreement and Plan of Merger with Emera provide that vesting of outstanding equity awards will be accelerated, as described under "Long-Term Incentive Awards," above.

*Post-Termination Benefits Table*

The table below shows the amounts that would be payable to each of the named executive officers in connection with a termination without cause or for good reason in contemplation of or following a change of control. There are no agreements or arrangements with these officers for any termination scenarios not involving a change in control.

The amounts below are calculated as if such event had occurred on Dec. 31, 2015, based on our closing stock price on that day of $26.65. Other assumptions that were made in order to calculate these amounts are that no accrued base salary or prorated incentive payment was owed on that date.

The change-in-control agreements provide enhancements to the benefit formula of the retirement plans, as described above, and the retirement-related benefits shown below are the incremental amounts representing the enhanced benefit. The tax-qualified defined benefit plan and supplemental executive retirement plan are described in more detail under "Pension Benefits" above, and the present value of accumulated benefits under our pension arrangements are shown in that section. Any value of such arrangements that is not directly attributable to the change in control is not included in this section.

Health care benefits are based on the continuation of benefits for three years at the officer's current level of coverage.

Under the terms of our change-in-control agreements, as described in more detail above, under certain circumstances Messrs. Ramil, Gillette and Attal would be eligible to receive an excise tax gross-up payment if additional taxes are due by that officer as a result of the application of the excise tax associated with Section 280G of the Internal Revenue Code. The amounts shown below are pre-tax; the officer would be responsible for paying income, excise, and any other applicable taxes on the amounts received.

| *Name* | *Cash Severance ($)* | *Accelerated Equity Vesting ($)* | *Health Care Benefits ($)* | *Retirement-Related Benefits ($)* | *Excise Tax Gross-Up ($)* | *Total ($)* |
|---|---|---|---|---|---|---|
| John B. Ramil | 5,130,000 | 17,016,451 | 38,634 | 476,434 | 9,628,064 | 32,289,583 |
| Sandra W. Callahan | 2,495,175 | 4,199,947 | 31,077 | 0 | 0 | 6,726,199 |
| Gordon L. Gillette | 2,784,600 | 4,033,731 | 48,171 | 346,067 | 2,874,538 | 10,087,107 |
| Charles A. Attal III | 1,878,720 | 2,987,692 | 31,077 | 820,442 | 2,478,614 | 8,196,545 |
| Phil L. Barringer | 1,767,000 | 2,757,436 | 48,171 | 0 | 0 | 4,572,607 |

**Item 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.**

**Share Ownership**

*Directors and Executive Officers*

The following table gives information regarding the shares of common stock beneficially owned as of Feb. 1, 2016 by our directors and nominees, the named executive officers, and directors and executive officers as a group. Except as otherwise noted, such persons have sole investment and voting power over the shares. The number of shares of our common stock beneficially owned by any director or executive officer did not exceed 1% of the total shares outstanding at Feb. 1, 2016; the percentage beneficially owned by all directors and executive officers as a group as of that date was 1.2%.

| Name | Shares [(1)] | Name | Shares [(1)] |
|---|---|---|---|
| James L. Ferman, Jr. | 30,012 [(2)] | William D. Rockford | 47,394 |
| Evelyn V. Follit | 15,231 | Paul L. Whiting | 136,454 [(7)] |
| Sherrill W. Hudson | 495,107 | Sandra W. Callahan | 181,982 [(4),(8)] |
| Joseph P. Lacher | 55,451 [(3)] | Gordon L. Gillette | 273,796 [(4),(9)] |
| Loretta A. Penn | 31,546 | Charles A. Attal III | 137,644 [(4)] |
| John B. Ramil | 597,544 [(4),(5)] | Phil L. Barringer | 127,292 [(4)] |
| Tom L. Rankin | 734,681 [(6)] | Clark Taylor | 38,316 [(4)] |
| | | All directors and executive officers as a group (15 persons) | 2,911,676 [(4),(10)] |

(1) The amounts listed include the following shares that are subject to options granted under our stock option plans (all of which are currently exercisable): Mr. Hudson, 138,200 shares; Mr. Barringer, 6,650 shares; and all directors and executive officers as a group, 144,850 shares. The amounts listed also include unvested restricted stock with respect to both directors and executive officers, and with respect to executive officers, unvested performance shares. Unvested restricted stock and performance shares cannot be transferred and are subject to forfeiture.

(2) Includes 18,125 shares owned jointly by Mr. Ferman and his wife. Also includes 2,772 shares owned by Mr. Ferman's wife, as to which shares he disclaims any beneficial interest.

(3) Includes 9,565 shares owned by Mr. Lacher's wife, as to which shares he disclaims any beneficial interest.

(4) Includes the following shares held by our benefit plans for an officer's account: Mr. Ramil, 11,484 shares; Mr. Gillette, 14,949 shares; Ms. Callahan, 9,005 shares; Mr. Attal, 922 shares; Mr. Barringer, 8,147 shares; Mr. Taylor, 33 shares and all directors and executive officers as a group, 44,540 shares.

(5) Includes 289,136 shares owned jointly by Mr. Ramil and his wife; also includes 4,791 shares owned by Mr. Ramil's son, as to which shares he disclaims any beneficial interest.

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

(7) Includes 41,393 shares owned jointly by Mr. Whiting and other family members; also includes 5,836 shares owned by Mr. Whiting's wife, and 2,500 shares held in a trust of which Mr. Whiting's wife is trustee, as to which shares he disclaims any beneficial interest.

(8) Includes 9,477 shares owned jointly by Ms. Callahan and her husband.

(9) Includes 1,042 shares owned by Mr. Gillette's daughter, as to which shares he disclaims any beneficial interest.

(10) Includes a total of 358,131 shares owned jointly. Also includes a total of 28,922 shares owned by family members, as to which shares beneficial interest is disclaimed.

*Five Percent Shareholders*

The following table gives information with respect to all persons who are known to us to be the beneficial owners of more than 5% of our outstanding common stock as of Dec. 31, 2015.

| Name and Address | Shares | Percent of Class |
|---|---|---|
| The Vanguard Group, Inc.<br>100 Vanguard Blvd., Malvern, PA 19355 | 20,125,724 (1) | 8.6% |
| BlackRock, Inc.<br>55 East 52nd Street, New York, NY 10055 | 16,340,409 (2) | 6.9% |

(1) Based on a Schedule 13G/A filed with the Securities and Exchange Commission on Feb. 10, 2016, which reported that the Vanguard Group, Inc. has sole voting and investment power over 397,795 and 19,749,529 of such shares, respectively, and shared voting and investment power over 11,400 and 376,195 of such shares, respectively, and that its wholly-owned subsidiaries, Vanguard Fiduciary Trust Company (VFTC) and Vanguard Investments Australia, Ltd. (VIA), are the beneficial owners of 364,795 and 44,400 of such shares, respectively, as a result of VFTC serving as investment manager of collective trust accounts and VIA serving as investment manager of Australian investment offerings.

(2) Based on a Schedule 13G/A filed with the Securities and Exchange Commission on Feb. 10, 2016, which reported that BlackRock, Inc. had sole investment power over these shares and sole voting power over 14,763,803 of these shares.

**Equity Compensation Plan Information**

| *(thousands, except per share price)* | *(a)* | *(b)* | *(c)* |
|---|---|---|---|
| *Plan Category* | *Number of securities to be issued upon exercise of outstanding options, warrants and rights (1)* | *Weighted-average exercise price per share of outstanding options, warrants and rights* | *Number of securities remaining available for Future issuance under equity compensation plans (excluding securities reflected in column (a)(2))* |
| **Equity compensation plans/arrangements approved by the stockholders** | | | |
| 2010 Equity Incentive Plan | 254 | $ 16.30 | 2,429 |
| **Equity compensation plans/arrangements not approved by the stockholders** | | | |
| None | 0 | 0.00 | 0 |
| Total | 254 | $ 16.30 | 2,429 |

(1) The reported amount for the 2010 Equity Incentive Plan excludes performance shares which have been issued or may potentially be issued due to performance, subject to a performance-based vesting schedule. Because of the nature of these awards, these shares have also not been taken into account in calculating the weighted-average exercise price under column (b) of this table.

(2) The reported amount for the 2010 Equity Incentive Plan includes shares which may be issued as restricted stock, performance shares, performance-accelerated restricted stock, bonus stock, phantom stock, performance units, dividend equivalents and other forms of award available for grant under the plan.

### Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE.

**Certain Relationships and Related Person Transactions**

Our Board has adopted a written policy regarding the review, approval or ratification of related person transactions. A related person transaction for the purposes of the policy is a transaction between the company and one of our directors, executive officers or 5% shareholders, or a member of one of these person’s immediate family, in which such person has a direct or indirect material interest and involves more than $120,000. Under this policy, related person transactions are prohibited unless the Audit Committee has determined in advance that the transaction is fair and reasonable to the company. The policy contains procedures that require the Audit Committee receive the following information regarding the transaction and consider the following factors before deciding whether to approve a proposed transaction:

- information regarding the parties involved in the transaction and their relationship to the company,
- a complete description of the material terms of the transaction, including economic and non-economic features,

- the direct and indirect interests present in the proposed transaction,
- the relationships present in the proposed transaction, and
- the conflicts or potential conflicts present in the proposed transaction.

After receiving such information and considering the above factors, the policy calls for the Audit Committee to determine, in its judgment, whether the transaction is fair and reasonable to the company, and whether or not such transaction should be approved on such basis. In the event the company enters into such a transaction without Audit Committee approval, the Audit Committee must promptly review its terms and may ratify the transaction if it determines it is fair and reasonable to the company and any failure to comply with the pre-approval policy was not due to fraud or deceit. In 2015, there were no related person transactions as defined above.

**Director Independence**

The Board has determined that all of the directors except Messrs. Hudson and Ramil meet the independence standards of the New York Stock Exchange and those set forth in our Corporate Governance Guidelines. The Board annually reviews business and charitable relationships of directors in order to make a determination as to the independence of each director. Only those directors who the Board affirmatively determines have no material relationship with us that would impair their independent judgment are considered independent directors. After performing such a review, the Board determined that (i) Mss. Penn and Follit and Mr. Rockford have no relationships with us except as directors and (ii) the only other relationships between the company and Messrs. Ferman, Lacher, Rankin and Whiting were charitable contributions by us in amounts below $100,000 to organizations of which these directors are board members. Since this type of relationship with us is not considered a material relationship under the categorical standards contained in our Corporate Governance Guidelines (described below), they were not considered by the Board as relationships that would affect their independence.

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

1. If a director is an employee, or if the immediate family member of the director is an executive officer, of another company that does business with us and the annual sales to, or purchases from, us are less than the greater of $1 million or 1% of the consolidated annual gross revenues of the company for which he or she serves as an executive officer or employee;
2. If a director is an executive officer of another company which is indebted to us, or to which we are indebted, and the total amount of either company's indebtedness to the other is less than 1% of the total consolidated assets of the company for which he or she serves as an executive officer; and
3. If a director is an executive officer, director or trustee of a charitable organization and our discretionary annual charitable contributions to the organization do not exceed the greater of $1 million or 1% of that organization's total annual charitable receipts.

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

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

1. A director shall not be independent if, within the preceding three years: (i) the director was employed by us; (ii) an immediate family member of the director was employed by us as an executive officer; (iii) the director or an immediate family member of the director received more than $120,000 in direct compensation from us, other than director fees, pension, or other deferred compensation for prior service in any 12-month period; or (iv) one of our executive officers was on the compensation committee of a company which during that same time period employed the director, or which employed an immediate family member of the director, as an executive officer.
2. A director shall not be independent if (i) the director is a current employee or partner of our independent or internal auditor; (ii) an immediate family member of the director is a current partner of our independent or internal auditor, or is a current employee who personally works on our audit; or (iii) the director or an immediate family member was a partner or an employee of the independent auditor and personally worked on our audit within the last three years.

For relationships the character of which are not included in the categories in paragraphs 1 or 2 above or do not meet the categorically immaterial standards described above, the determination of whether the relationship is material or not and, therefore, whether the director would be independent or not, shall be made by the directors who satisfy these independence guidelines.

**Item 14. PRINCIPAL ACCOUNTING FEES AND SERVICES.**

*Fees Paid by TECO Energy to the Independent Auditor*

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers LLP, our independent auditor (referred to throughout this Item as the "independent auditor"), for the audit of our annual financial statements for the years ended Dec. 31, 2015 and 2014, and fees billed for other services rendered by PricewaterhouseCoopers LLP during these periods.

| | 2015 | 2014 |
|---|---|---|
| Audit fees | $ 2,353,368 | $ 2,683,060 |
| Audit-related fees | 704,559 | 187,182 |
| Tax fees | | |
| Tax compliance fees | 0 | 0 |
| Tax planning fees | 42,889 | 47,762 |
| All other fees | 0 | 1,055,785 |
| Total | $ 3,100,816 | $ 3,973,789 |

Audit fees consist of fees for professional services performed for (i) the audit of our annual financial statements, including management's assessment of our internal control over financial reporting, (ii) the related reviews of the financial statements included in our 10-Q filings, (iii) services that are normally provided in connection with statutory and regulatory filings or engagements and (iv) subsidiary stand-alone financial statements.

Audit-related fees consist of fees for professional services that are reasonably related to the performance of the audit or review of our financial statements, such as due diligence services pertaining to potential and completed business acquisitions/dispositions and required activities related to debt and equity offerings. Audit-related fees for 2015 included $193,167 in support of financing activities related to the Merger that were, pursuant to the terms of the Merger Agreement, fully reimbursed to the company by Emera.

Tax fees consist of tax compliance fees for tax return review and income tax provision review, and tax planning fees, including tax audit advice.

All other fees consist of fees for other work performed by PricewaterhouseCoopers LLP, including fees for assessments and recommendations related to specific transactions, regulatory accounting advice and other miscellaneous services.

In the first half of 2013, we engaged Booz & Co., a consulting firm, to provide us with integration services in connection with our then-pending acquisition of New Mexico Gas Company. In October 2013, PricewaterhouseCoopers LLP entered into an agreement to acquire Booz & Co., which acquisition was completed in early 2014. The integration services provided by Booz & Co. (subsequently renamed Strategy&) after that closing totaled $1,053,985 and were pre-approved by the Audit Committee under the policy described below prior to the performance of the services. These fees are included in the "All other fees" disclosed for 2014. In engaging PricewaterhouseCoopers LLP as the company's independent auditor for 2014, the Audit Committee considered appropriate factors with respect to such services, including the size of the expected fees for such non-audit services (which did not exceed the sum of the 2014 audit fees, audit-related fees and tax fees payable to PricewaterhouseCoopers LLP), the nature of the services to be provided, the nature of the pre-existing relationship with Booz & Co., and the required communications regarding independence of PricewaterhouseCoopers LLP to the Audit Committee.

*Fees Paid by TEC to the Independent Auditor*

The following table presents fees for professional audit services rendered by PricewaterhouseCoopers LLP for the audit of TEC's annual financial statements for the years ended Dec. 31, 2015 and 2014, and fees billed for other services rendered by PricewaterhouseCoopers LLP during these periods.

| | 2015 | 2014 |
|---|---|---|
| Audit fees | $ 1,120,027 | $ 932,186 |
| Audit-related fees | 395,682 | 65,000 |
| Tax fees | | |
| Tax compliance fees | 0 | 0 |
| Tax planning fees | 0 | 14,424 |
| All other fees | 0 | 0 |
| Total | $ 1,515,709 | $ 1,011,610 |

*Audit Committee Pre-Approval Policy*

The Audit Committee has adopted a policy for pre-approval of services to be provided by our independent auditor. Under the policy, the Audit Committee pre-approves the annual audit engagement terms and fees and the specific types of services to be performed by the independent auditor throughout the year, based on the Audit Committee's determination that the provision of the services would not be likely to impair the auditor's independence. The pre-approval is effective for the current fiscal year and until the Audit Committee meets to re-approve services for the following year, or such other period as the Committee may designate. The policy permits the Audit Committee to delegate pre-approval authority to one or more of its members to ensure prompt handling of unexpected matters, with such delegated pre-approvals to be reported to the Audit Committee at its next meeting. The policy also contains a list of prohibited non-audit services and requires that the independent auditor ensure that all audit and non-audit services provided to us have been pre-approved by the Audit Committee.

# 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
      Report of Independent Registered Public Accounting Firm dated February 26, 2016 of PricewaterhouseCoopers LLP
      Consolidated Balance Sheets at December 31, 2015 and 2014
      Consolidated Statements of Income for the Years Ended December 31, 2015, 2014 and 2013
      Consolidated Statements of Comprehensive Income for the Years Ended December 31, 2015, 2014 and 2013
      Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013
      Consolidated Statements of Capital for the Years Ended December 31, 2015, 2014 and 2013
      Notes to Consolidated Financial Statements
   Tampa Electric Company Financial Statements
      Report of Independent Registered Public Accounting Firm dated February 26, 2016 of PricewaterhouseCoopers LLP
      Consolidated Balance Sheets at December 31, 2015 and 2014
      Consolidated Statements of Income and Comprehensive Income for the Years Ended December 31, 2015, 2014 and 2013
      Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013
      Consolidated Statements of Retained Earnings for the Years Ended December 31, 2015, 2014 and 2013
      Consolidated Statements of Capitalization for the Years Ended December 31, 2015, 2014 and 2013
      Notes to Consolidated Financial Statements

2. Financial Statement Schedules
   TECO Energy, Inc. Schedule II
   Tampa Electric Company Schedule II

3. Exhibits

(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, 2015, 2014 and 2013

*(millions)*

| | Balance at Beginning of Period | Additions: Charged to Income | Additions: Other Charges | Payments & Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| **Allowance for Uncollectible Accounts:** | | | | | |
| 2015 | $ 2.1 | $ 2.7 | $ 0.0 | $ 2.7 (1) | $ 2.1 |
| 2014 | $ 4.7 | $ 1.4 | $ 0.7 | $ 4.7 (1) | $ 2.1 |
| 2013 | $ 4.2 | $ 3.3 | $ 0.0 | $ 2.8 (1) | $ 4.7 |
| **Deferred Tax Valuation Allowance:** | | | | | |
| 2015 | $ 4.6 | $ 1.0 | $ 0.0 | $ 3.6 (2) | $ 2.0 |
| 2014 | $ 0.0 | $ 4.6 | $ 0.0 | $ 0.0 | $ 4.6 |
| 2013 | $ 3.0 | $ 0.0 | $ 0.0 | $ 3.0 (2) | $ 0.0 |

(1) Write-off of individual bad debt accounts
(2) Release of valuation allowance

## SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

### TAMPA ELECTRIC COMPANY
### VALUATION AND QUALIFYING ACCOUNTS AND RESERVES
### For the Years Ended Dec. 31, 2015, 2014 and 2013

*(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:** | | | | | |
| 2015 | $ 1.4 | $ 2.7 | $ 0.0 | $ 2.6 | $ 1.5 |
| 2014 | $ 2.0 | $ 2.7 | $ 0.0 | $ 3.3 | $ 1.4 |
| 2013 | $ 1.5 | $ 3.3 | $ 0.0 | $ 2.8 | $ 2.0 |

(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 26, 2016

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 26, 2016:

| Signature | Title |
|---|---|
| /s/ JOHN B. RAMIL<br>JOHN B. RAMIL | President, Chief Executive Officer and Director<br>(Principal Executive Officer) |
| /s/ SANDRA W. CALLAHAN<br>SANDRA W. CALLAHAN | Senior Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer)<br>(Principal Financial and Principal Accounting Officer) |

| Signature | Title | Signature | Title |
|---|---|---|---|
| /s/ JAMES L. FERMAN, JR.<br>JAMES L. FERMAN, JR. | Director | /s/ LORETTA A. PENN<br>LORETTA A. PENN | Director |
| /s/ EVELYN V. FOLLIT<br>EVELYN V. FOLLIT | Director | /s/ TOM L. RANKIN<br>TOM L. RANKIN | Director |
| /s/ SHERRILL W. HUDSON<br>SHERRILL W. HUDSON | Chairman of the Board and Director | /s/ WILLIAM D. ROCKFORD<br>WILLIAM D. ROCKFORD | Director |
| /s/ JOSEPH P. LACHER<br>JOSEPH P. LACHER | Director | /s/ PAUL L. WHITING<br>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 26, 2016

By: /s/ JOHN B. RAMIL
JOHN B. RAMIL
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 26, 2016:

| | Title |
|---|---|
| /s/ JOHN B. RAMIL<br>JOHN B. RAMIL | Chief Executive Officer and Director<br>(Principal Executive Officer) |
| /s/ SANDRA W. CALLAHAN<br>SANDRA W. CALLAHAN | Vice President-Finance and Accounting and Chief Financial Officer (Chief Accounting Officer)<br>(Principal Financial and Principal Accounting Officer) |

| Signature | Title | Signature | Title |
|---|---|---|---|
| /s/ JAMES L. FERMAN, JR.<br>JAMES L. FERMAN, JR. | Director | /s/ LORETTA A. PENN<br>LORETTA A. PENN | Director |
| /s/ EVELYN V. FOLLIT<br>EVELYN V. FOLLIT | Director | /s/ TOM L. RANKIN<br>TOM L. RANKIN | Director |
| /s/ SHERRILL W. HUDSON<br>SHERRILL W. HUDSON | Chairman of the Board and Director | /s/ WILLIAM D. ROCKFORD<br>WILLIAM D. ROCKFORD | Director |
| /s/ JOSEPH P. LACHER<br>JOSEPH P. LACHER | Director | /s/ PAUL L. WHITING<br>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 | 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.). | * |
| 2.2 | Agreement and Plan of Merger, dated as of Sept. 4, 2015, by and among TECO Energy, Emera and Merger Sub (Exhibit 2.1, Form 8-K dated Sept. 8, 2015 of TECO Energy, Inc.). | * |
| 2.3 | Securities Purchase Agreement dated as of Sept. 21, 2015, by and between TECO Diversified, Inc., as Seller, and Cambrian Coal Corporation, as Purchaser (Exhibit 2.1, Form 8-K dated Sept. 21, 2015 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 3.2, Form 8-K dated May 4, 2012 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 2010 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 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). | * |
| 4.3 | 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). | * |
| 4.4 | 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). | * |
| 4.5 | 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). | * |
| 4.6 | 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). | * |
| 4.7 | 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). | * |
| 4.8 | 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). | * |
| 4.9 | 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). | * |
| 4.10 | 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). | * |
| 4.11 | 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). | * |

| Exhibit No. | Description | |
|---|---|---|
| 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 | Eleventh Supplemental Indenture dated as of May 12, 2014 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 4.35% Notes due 2044) (Exhibit 4.27, Form 8-K dated May 15, 2014). | * |
| 4.17 | 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.). | * |
| 4.18 | 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.). | * |
| 4.19 | 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.). | * |
| 4.20 | 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.). | * |
| 4.21 | 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.). | * |
| 4.22 | 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.). | * |
| 4.23 | 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.). | * |
| 4.24 | 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.). | * |
| 4.25 | 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.). | * |
| 4.26 | 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.). | * |
| 4.27 | 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.). | * |
| 4.28 | 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.). | * |
| 4.29 | Twentieth Supplemental Indenture dated as of December 1, 2013 between Tampa Electric Company and US Bank, N.A., as successor trustee, amending and restating 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 (Exhibit 4.30, Form 10-K for 2013 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 4.30 | Note Purchase Agreement, dated as of February 8, 2011, by and among New Mexico Gas Company, Inc. and the | * |

| Exhibit No. | Description | |
|---|---|---|
| | purchasers party thereto (including the Form of Senior Secured Note as Exhibit 1.1 thereto) (Exhibit 4.1, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | |
| 4.31 | Amendment No. 1 to Note Purchase Agreement, dated as of July 16, 2014, by and between New Mexico Gas Company, Inc. and the noteholders party thereto, to the Note Purchase Agreement dated as of February 8, 2011, by and among New Mexico Gas Company, Inc. and the purchasers party thereto (Exhibit 4.2, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 4.32 | Amendment No. 2 to Note Purchase Agreement, dated as of July 16, 2014, by and between New Mexico Gas Company, Inc. and the noteholders party thereto, to the Note Purchase Agreement dated as of February 8, 2011, as amended, by and among New Mexico Gas Company, Inc. and the purchasers party thereto (Exhibit 4.3, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 4.33 | Note Purchase Agreement, dated as of July 30, 2014, by and among New Mexico Gas Company, Inc. and the purchasers party thereto (including the Form of Senior Unsecured Note as Exhibit 1 thereto) (Exhibit 4.4, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 4.34 | Note Purchase Agreement, dated as of July 30, 2014, by and among New Mexico Gas Intermediate, Inc. and the purchasers party thereto (including the Form of Series A Senior Unsecured Note as Exhibit 1(a) thereto and Form of Series B Senior Unsecured Note as Exhibit 1(b) thereto) (Exhibit 4.5, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 4.35 | Fourth Supplemental Indenture dated as of Apr. 10, 2015, among TECO Finance, Inc., as issuer, TECO Energy, Inc., as guarantor, and The Bank of New York Mellon Trust Company, N.A., as trustee and calculation agent, supplementing the Indenture dated as of Dec. 21, 2007 (including the form of Floating Rate Notes due 2018) (Exhibit 4.22, Form 8-K dated Apr. 10, 2015 of TECO Energy, Inc.). | * |
| 4.36 | Twelfth Supplemental Indenture dated as of May 20, 2015, 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 4.20% Notes due 2045) (Exhibit 4.24, Form 8-K dated May 20, 2015 of Tampa Electric Company). | * |
| 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 | TECO Energy Group Benefit Restoration Plan dated as of Nov. 13, 2015. | |
| 10.5 | 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). | * |
| 10.6 | 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 Sept. 30, 2008 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.7 | 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.). | * |
| 10.8 | 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 Sept. 30, 2007 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.9 | 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 June 30, 2009 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.10 | 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 June 30, 1999 of TECO Energy, Inc.). | * |
| 10.11 | TECO Energy, Inc. 1997 Director Equity Plan (Exhibit 10.1, Form 8-K dated Apr. 16, 1997 of TECO Energy, Inc.). | * |
| 10.12 | 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). | * |

| Exhibit No. | Description | |
|---|---|---|
| 10.13 | 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). | * |
| 10.14 | 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 June 30, 2009 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.15 | 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 June 30, 2009 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.16 | Nonstatutory Stock Option granted to S. W. Hudson, dated as of July 6, 2004, under the TECO Energy, Inc. 2004 Equity Incentive Plan (Exhibit 10.1, Form 10-Q for the quarter ended June 30, 2004 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.17 | 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.). | * |
| 10.18 | 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 June 30, 2010 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.19 | 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 June 30, 2010 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.20 | 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 June 30, 2010 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.21 | 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 Mar. 31, 2013). | * |
| 10.22 | Form of Performance Shares Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan, as amended (Exhibit 10.1, Form 10-Q for the quarter ended Mar. 31, 2015). | * |
| 10.23 | Form of Restricted Stock Agreement between TECO Energy, Inc. and certain officers under the TECO Energy, Inc. 2010 Equity Incentive Plan, as amended (Exhibit 10.2, Form 10-Q for the quarter ended Mar. 31, 2015). | * |
| 10.24 | Compensatory Arrangements with Executive Officers of TECO Energy, Inc. | |
| 10.25 | Compensatory Arrangements with Non-Management Directors of TECO Energy, Inc. | |
| 10.26 | 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). | * |
| 10.27 | 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). | * |
| 10.28 | Retention Agreement dated as of August 14, 2014 with Clark Taylor (Exhibit 10.9, Form 10-Q for the quarter ended Sept. 31, 2014). | * |
| 10.29 | Voluntary Retirement Agreement and General Release between TECO Services, Inc. and Deirdre A. Brown dated as of Nov. 11, 2014 (Exhibit 10.26, Form 10-K for the year ended Dec. 31, 2014 of TECO Energy, Inc.). | * |
| 10.30 | Separation Agreement and General Release between New Mexico Gas Company, Inc. and Annette Gardiner dated as of Dec. 1, 2014 (Exhibit 10.27, Form 10-K for the year ended Dec. 31, 2014 of TECO Energy, Inc.). | * |
| 10.31 | 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). | * |
| 10.32 | 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.). | * |

| Exhibit No. | Description | |
|---|---|---|
| 10.33 | 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). | * |
| 10.34 | 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). | * |
| 10.35 | 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). | * |
| 10.36 | 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). | * |
| 10.37 | 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). | * |
| 10.38 | 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). | * |
| 10.39 | 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, N.A. as Program Agent (Exhibit 10.37, Form 10-K for 2010 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.41 | 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, N.A. as Program Agent (Exhibit 10.38, Form 10-K for 2011 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.41 | 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, N.A. as Program Agent (Exhibit 10.39, Form 10-K for 2012 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.42 | 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. as Program Agent (Exhibit 10.37, Form 10-K for 2013 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.43 | Amendment No. 13 to Loan and Servicing Agreement dated as of Feb. 3, 2015, among TEC Receivables Corp. as Borrower, Tampa Electric Company as Servicer, certain lenders named therein and Citibank, N.A. as Program Agent (Exhibit 10.40, Form 10-K for the year ended Dec. 31, 2014 of TECO Energy, Inc.). | * |
| 10.44 | Amended and Restated Purchase and Contribution Agreement dated as of Mar. 24, 2015, between Tampa Electric Company, as the Originator, and TEC Receivables Corp., as the Purchaser (Exhibit 10.1, Form 8-K dated Mar. 24, 2015 of TECO Energy, Inc.). | * |
| 10.45 | Loan and Servicing Agreement dated as of Mar. 24, 2015, among TEC Receivables Corp., as Borrower, Tampa Electric Company, as Servicer, certain lenders named therein, and The Bank of Tokyo-Mitsubishi UFJ, Ltd., New York Branch, as Program Agent (Exhibit 10.2, Form 8-K dated Mar. 24, 2015 of TECO Energy, Inc.). | * |
| 10.46 | 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.). | * |
| 10.47 | 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.). | * |
| 10.48 | Fourth Amended and Restated Credit Agreement dated as of Dec. 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 | * |

| Exhibit No. | Description | |
|---|---|---|
| | Issuing Banks party thereto (Exhibit 10.1, Form 8-K dated Dec. 17, 2013 of TECO Energy, Inc. and Tampa Electric Company). | |
| 10.49 | Fourth Amended and Restated Credit Agreement dated as of Dec. 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). | * |
| 10.50 | Credit Agreement dated as of Dec. 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). | * |
| 10.51 | Amendment No. 1, dated as of July 31, 2014, to the Senior Unsecured Bridge Credit Agreement, dated as of June 24, 2013, by and among TECO Finance, Inc., as Borrower, TECO Energy, Inc., as Guarantor, Morgan Stanley Senior Funding, Inc., as Administrative Agent, and the Lenders party thereto (Exhibit 10.1, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.52 | Amendment No. 1, dated as of Aug. 1, 2014, to the Fourth Amended and Restated Credit Agreement dated as of Dec. 17, 2013, 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 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.53 | Amendment No. 1, dated as of Aug. 1, 2014, to the Fourth Amended and Restated Credit Agreement dated as of Dec. 17, 2013, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.3, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.54 | Amendment No. 1, dated as of Aug. 1, 2014, to the 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 party thereto (Exhibit 10.4, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.55 | Joinder and Release Agreement, dated as of Sept. 2, 2014, among TECO Energy, Inc., New Mexico Gas Company, Inc. and JPMorgan Chase Bank, N.A., as Administrative Agent, to the Credit Agreement dated as of Dec. 17, 2013, as amended, among TECO Energy, Inc., as Initial Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.5, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.56 | Amendment No. 2, dated as of Sept. 30, 2014, to the Fourth Amended and Restated Credit Agreement dated as of Dec. 17, 2013, as amended, 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 10.6, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.57 | Amendment No. 2, dated as of Sept. 30, 2014, to the Fourth Amended and Restated Credit Agreement dated as of Dec. 17, 2013, as amended, among Tampa Electric Company, as Borrower, Citibank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.7, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.58 | Amendment No. 2, dated as of Sept. 30, 2014, to the Credit Agreement dated as of Dec. 17, 2013, as amended, among New Mexico Gas Company, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto (Exhibit 10.8, Form 10-Q for the quarter ended Sept. 30, 2014 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 10.59 | Amendment No. 3, dated as of Feb. 24, 2016, to the Fourth Amended and Restated Credit Agreement dated as of Dec. 17, 2013, as amended, among TECO Finance, Inc., as Borrower, TECO Energy, Inc., as Guarantor, JPMorgan Chase Bank, N.A., as Administrative Agent, and the Lenders party thereto. | |
| 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. | |

| Exhibit No. | Description |
|---|---|
| 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 10.30, above are management contracts or compensatory plans or arrangements in which executive officers or directors of TECO Energy, Inc. participate.

**Exhibit 12.1**

## TECO ENERGY, INC.
## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth TECO Energy's ratio of earnings to fixed charges for the periods indicated.

| | Year Ended Dec. 31, | | | | |
|---|---|---|---|---|---|
| (millions) | 2015 | 2014 | 2013 | 2012 | 2011 |
| Income from continuing operations, before income taxes | $ 396.5 | $ 345.3 | $ 301.3 | $ 317.8 | $ 326.5 |
| Interest expense | 201.8 | 181.3 | 169.2 | 180.9 | 193.3 |
| Earnings before taxes and fixed charges | $ 598.3 | $ 526.6 | $ 470.5 | $ 498.7 | $ 519.8 |
| Interest expense | $ 201.8 | $ 181.3 | $ 169.2 | $ 180.9 | $ 193.3 |
| Total fixed charges | $ 201.8 | $ 181.3 | $ 169.2 | $ 180.9 | $ 193.3 |
| Ratio of earnings to fixed charges | 2.96x | 2.90x | 2.78x | 2.76x | 2.69x |

For the purposes of calculating these ratios, earnings consist of income from continuing operations before income taxes and fixed charges. Fixed charges consist of interest expense on indebtedness, amortization of debt premium and an estimate of the interest component of rentals. Interest expense includes total interest expense, excluding AFUDC, and an estimate of the interest component of rentals. TECO Energy, Inc. does not have any preferred stock outstanding, and there were no preferred stock dividends paid or accrued during the periods presented.

The sale of TECO Guatemala was completed in December 2012, and TECO Guatemala is considered a discontinued operation. Prior periods presented have been adjusted to reflect the classification of TECO Guatemala as discontinued operations.

The sale of TECO Coal was completed in September 2015, and TECO Coal is considered a discontinued operation. Prior periods presented have been adjusted to reflect the classification of TECO Coal as discontinued operations.

**Exhibit 12.2**

## TAMPA ELECTRIC COMPANY
## RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth Tampa Electric Company's ratio of earnings to fixed charges for the periods indicated.

| | Year Ended Dec. 31, | | | | |
|---|---|---|---|---|---|
| (millions) | 2015 | 2014 | 2013 | 2012 | 2011 |
| Income from continuing operations, before income taxes | $ 441.8 | $ 416.2 | $ 364.4 | $ 368.9 | $ 380.7 |
| Interest expense | 122.1 | 115.8 | 112.7 | 129.9 | 141.9 |
| Earnings before taxes and fixed charges | $ 563.9 | $ 532.0 | $ 477.1 | $ 498.8 | $ 522.6 |
| Interest expense | $ 122.1 | $ 115.8 | $ 112.7 | $ 129.9 | $ 141.9 |
| Total fixed charges | $ 122.1 | $ 115.8 | $ 112.7 | $ 129.9 | $ 141.9 |
| Ratio of earnings to fixed charges | 4.62x | 4.59x | 4.23x | 3.84x | 3.68x |

For the purposes of calculating these ratios, earnings consist of income from continuing operations before income taxes and fixed charges. Fixed charges consist of interest expense on indebtedness, amortization of debt premium and an estimate of the interest component of rentals. Interest expense includes total interest expense, excluding AFUDC, and an estimate of the interest component of rentals.

# Exhibit A-2

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

# FORM 10-Q

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

**For the quarterly period ended June 30, 2016**

**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.**<br>(a Florida corporation)<br>TECO Plaza<br>702 N. Franklin Street<br>Tampa, Florida 33602<br>(813) 228-1111 | **59-2052286** |
| **1-5007** | **TAMPA ELECTRIC COMPANY**<br>(a Florida corporation)<br>TECO Plaza<br>702 N. Franklin Street<br>Tampa, Florida 33602<br>(813) 228-1111 | **59-0475140** |

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 ☒ NO ☐

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate website, 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 ☒ NO ☐

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 | ☒ | 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 | ☒ | Smaller reporting company | ☐ |

Indicate by check mark whether TECO Energy, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

Indicate by check mark whether Tampa Electric Company is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

As of July 29, 2016, there were 1,000 shares of TECO Energy, Inc.’s common stock outstanding, all of which were held, beneficially and of record, by Emera Inc. As of July 29, 2016, 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.

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

This combined Form 10-Q 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. Each registrant makes representations only as to information relating to itself and its subsidiaries.

## 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 |
| 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 |
| CAIR | Clean Air Interstate Rule |
| Cambrian | Cambrian Coal Corporation |
| capacity clause | capacity cost-recovery clause, as established by the FPSC |
| CCRs | coal combustion residuals |
| CES | Continental Energy Systems |
| CMO | collateralized mortgage obligation |
| CNG | compressed natural gas |
| company | TECO Energy, Inc. |
| CPI | consumer price index |
| CSAPR | Cross State Air Pollution Rule |
| $CO_2$ | carbon dioxide |
| CT | combustion turbine |
| DR-CAFTA | Dominican Republic Central America – United States Free Trade Agreement |
| ECRC | environmental cost recovery clause |
| EEI | Edison Electric Institute |
| EGWP | Employee Group Waiver Plan |
| Emera | Emera Inc., a geographically diverse energy and services company headquartered in Nova Scotia, Canada |
| EPA | U.S. Environmental Protection Agency |
| EPS | earnings per share |
| ERISA | Employee Retirement Income Security Act |
| EROA | expected return on plan assets |
| 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 |
| GCBF | gas cost billing factor |
| GHG | greenhouse gas(es) |
| HAFTA | Highway and Transportation Funding Act |
| HCIDA | Hillsborough County Industrial Development Authority |
| ICSID | International Centre for the Settlement of Investment Disputes |
| IGCC | integrated gasification combined-cycle |
| IOU | investor owned utility |
| IRS | Internal Revenue Service |
| ISDA | International Swaps and Derivatives Association |
| 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 | the section of this report entitled Management's Discussion and Analysis of Financial Condition and Results of Operations |
| Merger | Merger of Merger Sub with and into TECO Energy, with TECO Energy as the surviving corporation |
| Merger Agreement | Agreement and Plan of Merger dated Sept. 4, 2015, by and among TECO Energy, Emera and Merger Sub |
| Merger Sub | Emera US Inc., a Florida corporation |
| MMA | The Medicare Prescription Drug, Improvement and Modernization Act of 2003 |

| Term | Meaning |
|---|---|
| MMBTU | one million British Thermal Units |
| MRV | market-related value |
| MW | megawatt(s) |
| MWH | megawatt-hour(s) |
| NAESB | North American Energy Standards Board |
| NAV | net asset value |
| NMGC | New Mexico Gas Company, Inc. |
| 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 |
| OCI | other comprehensive income |
| OPC | Office of Public Counsel |
| OPEB | other postretirement benefits |
| OTC | over-the-counter |
| Parent | TECO Energy (the holding company, excluding subsidiaries) |
| PBGC | Pension Benefit Guarantee Corporation |
| PBO | postretirement benefit obligation |
| PCI | pulverized coal injection |
| PGA | purchased gas adjustment |
| PGAC | purchased gas adjustment clause |
| PGS | Peoples Gas System, the gas division of Tampa Electric Company |
| PPA | power purchase agreement |
| PPSA | Power Plant Siting Act |
| PRP | potentially responsible party |
| REIT | real estate investment trust |
| RFP | request for proposal |
| ROE | return on common equity |
| Regulatory ROE | return on common equity as determined for regulatory purposes |
| ROW | rights-of-way |
| 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 | Securities Purchase Agreement dated Sept. 21, 2015, by and between TECO Diversified and Cambrian relating to the purchase of TECO Coal by Cambrian |
| 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 Coal | TECO Coal LLC, and its subsidiaries, a coal producing subsidiary of TECO Diversified |
| TECO Diversified | TECO Diversified, Inc., a subsidiary of TECO Energy, Inc. and parent of TECO Coal Corporation |
| TECO Energy | TECO Energy, Inc. |
| 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 |
| TGH | TECO Guatemala Holdings, LLC |
| TRC | TEC Receivables Company |
| TSI | TECO Services, Inc. |
| U.S. GAAP | generally accepted accounting principles in the United States |
| VIE | variable interest entity |
| WRERA | The Worker, Retiree and Employer Recovery Act of 2008 |

# PART I. FINANCIAL INFORMATION

## Item 1. CONSOLIDATED CONDENSED FINANCIAL STATEMENTS

# TECO ENERGY, INC.
## Consolidated Condensed Balance Sheets
## Unaudited

| *Assets* <br> *(millions)* | *June 30, 2016* | *Dec. 31, 2015* |
|---|---|---|
| **Current assets** | | |
| Cash and cash equivalents | $ 29.2 | $ 23.8 |
| Receivables, less allowance for uncollectibles of $2.0 and $2.1 at June 30, 2016 and Dec. 31, 2015, respectively | 256.5 | 280.7 |
| Inventories, at average cost | | |
| Fuel | 106.8 | 113.4 |
| Materials and supplies | 78.8 | 76.8 |
| Regulatory assets | 18.4 | 44.8 |
| Prepayments and other current assets | 29.4 | 30.8 |
| Total current assets | 519.1 | 570.3 |
| **Property, plant and equipment** | | |
| Utility plant in service | | |
| Electric | 7,419.5 | 7,270.3 |
| Gas | 2,191.9 | 2,113.8 |
| Construction work in progress | 855.9 | 794.7 |
| Other property | 16.4 | 15.9 |
| Property, plant and equipment, at original costs | 10,483.7 | 10,194.7 |
| Accumulated depreciation | (2,810.1) | (2,712.9) |
| Total property, plant and equipment, net | 7,673.6 | 7,481.8 |
| **Other assets** | | |
| Regulatory assets | 392.9 | 395.2 |
| Goodwill | 408.4 | 408.4 |
| Deferred charges and other assets | 85.7 | 77.8 |
| Total other assets | 887.0 | 881.4 |
| **Total assets** | $ 9,079.7 | $ 8,933.5 |

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

**TECO ENERGY, INC.**
**Consolidated Condensed Balance Sheets - continued**
**Unaudited**

| *Liabilities and Capital* *(millions)* | *June 30, 2016* | *Dec. 31, 2015* |
|---|---|---|
| **Current liabilities** | | |
| Long-term debt due within one year | $ 0.0 | $ 333.3 |
| Notes payable | 615.0 | 247.0 |
| Accounts payable | 295.1 | 255.4 |
| Customer deposits | 168.5 | 182.1 |
| Regulatory liabilities | 130.1 | 84.8 |
| Derivative liabilities | 1.1 | 24.1 |
| Interest accrued | 34.3 | 36.2 |
| Taxes accrued | 46.0 | 13.2 |
| Dividends declared | 26.8 | 0.0 |
| Other | 21.8 | 22.6 |
| Total current liabilities | 1,338.7 | 1,198.7 |
| | | |
| **Other liabilities** | | |
| Deferred income taxes | 635.1 | 570.7 |
| Investment tax credits | 10.3 | 10.5 |
| Regulatory liabilities | 723.8 | 715.8 |
| Deferred credits and other liabilities | 371.5 | 389.6 |
| Long-term debt, less amount due within one year | 3,490.0 | 3,489.2 |
| Total other liabilities | 5,230.7 | 5,175.8 |
| | | |
| **Commitments and contingencies (see Note 10)** | | |
| | | |
| **Capital** | | |
| Common equity (400.0 million shares authorized; par value $1; 235.5 million and 235.3 million shares outstanding at June 30, 2016 and Dec. 31, 2015, respectively) | 235.5 | 235.3 |
| Additional paid in capital | 1,898.5 | 1,894.5 |
| Retained earnings | 387.7 | 441.4 |
| Accumulated other comprehensive loss | (11.4) | (12.2) |
| Total capital | 2,510.3 | 2,559.0 |
| **Total liabilities and capital** | $ 9,079.7 | $ 8,933.5 |

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

**TECO ENERGY, INC.**
**Consolidated Condensed Statements of Income**
**Unaudited**

| *(millions, except per share amounts)* | | *Three months ended June 30,* *2016* | *2015* |
|---|---|---|---|
| **Revenues** | | | |
| Regulated electric | | $ 498.0 | $ 531.7 |
| Regulated gas | | 151.4 | 146.5 |
| Unregulated | | 2.9 | 2.4 |
| Total revenues | | 652.3 | 680.6 |
| **Expenses** | | | |
| Regulated operations and maintenance | | | |
| Fuel | | 137.4 | 171.8 |
| Purchased power | | 27.8 | 19.6 |
| Cost of natural gas sold | | 50.8 | 49.1 |
| Other | | 154.6 | 155.4 |
| Operations and maintenance other expense | | 1.4 | 1.1 |
| Merger transaction-related costs | | 71.4 | 0.0 |
| Depreciation and amortization | | 90.2 | 87.0 |
| Taxes, other than income | | 52.0 | 53.3 |
| Total expenses | | 585.6 | 537.3 |
| **Income from operations** | | 66.7 | 143.3 |
| **Other income** | | | |
| Allowance for other funds used during construction | | 5.9 | 3.7 |
| Other income, net | | 1.0 | 1.4 |
| Total other income | | 6.9 | 5.1 |
| **Interest charges** | | | |
| Interest expense | | 46.7 | 48.2 |
| Allowance for borrowed funds used during construction | | (2.9) | (1.8) |
| Total interest charges | | 43.8 | 46.4 |
| **Income from continuing operations before provision for income taxes** | | 29.8 | 102.0 |
| Provision for income taxes | | 24.3 | 40.5 |
| **Net income from continuing operations** | | 5.5 | 61.5 |
| **Discontinued operations** | | | |
| Loss from discontinued operations | | (0.4) | (78.1) |
| Benefit for income taxes | | (0.2) | (28.4) |
| Loss from discontinued operations, net | | (0.2) | (49.7) |
| **Net income** | | $ 5.3 | $ 11.8 |
| **Average common shares outstanding** | – Basic | 234.3 | 233.0 |
| | – Diluted | 235.5 | 233.6 |
| **Earnings per share from continuing operations** | – Basic | $ 0.03 | $ 0.26 |
| | – Diluted | $ 0.03 | $ 0.26 |
| **Earnings per share from discontinued operations** | – Basic | $ 0.00 | $ (0.21) |
| | – Diluted | $ 0.00 | $ (0.21) |
| **Earnings per share** | – Basic | $ 0.03 | $ 0.05 |
| | – Diluted | $ 0.03 | $ 0.05 |
| Dividends paid per common share outstanding | | $ 0.230 | $ 0.225 |

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

# TECO ENERGY, INC.
## Consolidated Condensed Statements of Income
## Unaudited

| *(millions, except per share amounts)* | | *Six months ended June 30, 2016* | *2015* |
|---|---|---|---|
| **Revenues** | | | |
| Regulated electric | | $ 921.4 | $ 981.4 |
| Regulated gas | | 384.3 | 386.7 |
| Unregulated | | 6.1 | 5.5 |
| Total revenues | | 1,311.8 | 1,373.6 |
| **Expenses** | | | |
| Regulated operations and maintenance | | | |
| Fuel | | 252.6 | 315.9 |
| Purchased power | | 42.2 | 36.7 |
| Cost of natural gas sold | | 147.6 | 152.1 |
| Other | | 296.9 | 299.1 |
| Operations and maintenance other expense | | 1.3 | 2.7 |
| Merger transaction-related costs | | 71.5 | 0.0 |
| Depreciation and amortization | | 180.0 | 172.5 |
| Taxes, other than income | | 104.9 | 105.1 |
| Total expenses | | 1,097.0 | 1,084.1 |
| **Income from operations** | | 214.8 | 289.5 |
| **Other income** | | | |
| Allowance for other funds used during construction | | 11.6 | 7.5 |
| Other income, net | | 2.5 | 3.0 |
| Total other income | | 14.1 | 10.5 |
| **Interest charges** | | | |
| Interest expense | | 95.6 | 98.0 |
| Allowance for borrowed funds used during construction | | (5.9) | (3.7) |
| Total interest charges | | 89.7 | 94.3 |
| **Income from continuing operations before provision for income taxes** | | 139.2 | 205.7 |
| Provision for income taxes | | 60.0 | 80.4 |
| **Net income from continuing operations** | | 79.2 | 125.3 |
| **Discontinued operations** | | | |
| Loss from discontinued operations | | (0.2) | (87.7) |
| Benefit for income taxes | | (0.1) | (32.2) |
| Loss from discontinued operations, net | | (0.1) | (55.5) |
| **Net income** | | $ 79.1 | $ 69.8 |
| **Average common shares outstanding** | – Basic | 234.1 | 232.9 |
| | – Diluted | 235.4 | 233.5 |
| **Earnings per share from continuing operations** | – Basic | $ 0.34 | $ 0.53 |
| | – Diluted | $ 0.34 | $ 0.53 |
| **Earnings per share from discontinued operations** | – Basic | $ 0.00 | $ (0.23) |
| | – Diluted | $ 0.00 | $ (0.23) |
| **Earnings per share** | – Basic | $ 0.34 | $ 0.30 |
| | – Diluted | $ 0.34 | $ 0.30 |
| Dividends paid per common share outstanding | | $ 0.46 | $ 0.45 |

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

**TECO ENERGY, INC.**
**Consolidated Condensed Statements of Comprehensive Income**
**Unaudited**

| | *Three months ended June 30,* | | *Six months ended June 30,* | |
|---|---|---|---|---|
| *(millions)* | *2016* | *2015* | *2016* | *2015* |
| **Net income** | $ 5.3 | $ 11.8 | $ 79.1 | $ 69.8 |
| **Other comprehensive income, net of tax** | | | | |
| Gain on cash flow hedges | 0.2 | 2.8 | 0.4 | 3.1 |
| Amortization of unrecognized benefit costs and other | (0.2) | 1.0 | 0.3 | 1.6 |
| Recognized cost due to curtailment | 0.1 | 0.0 | 0.1 | 0.0 |
| Other comprehensive income, net of tax | 0.1 | 3.8 | 0.8 | 4.7 |
| **Comprehensive income** | $ 5.4 | $ 15.6 | $ 79.9 | $ 74.5 |

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

# TECO ENERGY, INC.
## Consolidated Condensed Statements of Cash Flows
## Unaudited

| *(millions)* | *Six months ended June 30, 2016* | *2015* |
|---|---|---|
| **Cash flows from operating activities** | | |
| Net income | $ 79.1 | $ 69.8 |
| Adjustments to reconcile net income to net cash from operating activities: | | |
| Depreciation and amortization | 180.0 | 173.3 |
| Deferred income taxes and investment tax credits | 60.3 | 46.9 |
| Allowance for other funds used during construction | (11.6) | (7.5) |
| Non-cash stock compensation | 6.4 | 6.9 |
| Loss on disposals of business/assets, pretax | 0.3 | 0.0 |
| Deferred recovery clauses | 42.5 | (4.1) |
| Asset impairment, pretax | 0.0 | 78.6 |
| Receivables, less allowance for uncollectibles | 24.2 | 39.8 |
| Inventories | 4.6 | (37.2) |
| Prepayments and other current assets | 2.9 | (12.2) |
| Taxes accrued | 35.9 | 19.0 |
| Interest accrued | (1.9) | (1.8) |
| Accounts payable | 55.7 | (58.3) |
| Other | (20.2) | (15.1) |
| Cash flows from operating activities | 458.2 | 298.1 |
| **Cash flows from investing activities** | | |
| Capital expenditures | (384.8) | (335.7) |
| Net proceeds from sale of business/assets | 8.7 | 0.0 |
| Other investing activities | (0.2) | (0.1) |
| Cash flows used in investing activities | (376.3) | (335.8) |
| **Cash flows from financing activities** | | |
| Dividends and dividend equivalents | (108.6) | (105.9) |
| Proceeds from the sale of common stock | 4.1 | 3.5 |
| Proceeds from long-term debt issuance | 0.0 | 500.0 |
| Repayment of long-term debt | (333.3) | (274.5) |
| Net decrease in short-term debt (maturities of 90 days or less) | (32.0) | (53.5) |
| Proceeds from other short-term debt (maturities over 90 days) | 400.0 | 0.0 |
| Other financing activities | (6.7) | (1.3) |
| Cash flows from (used in) financing activities | (76.5) | 68.3 |
| **Net increase in cash and cash equivalents** | 5.4 | 30.6 |
| **Cash and cash equivalents at beginning of the period** | 23.8 | 25.4 |
| **Cash and cash equivalents at end of the period** | $ 29.2 | $ 56.0 |
| **Supplemental disclosure of non-cash activities** | | |
| Change in accrued capital expenditures | $ (14.2) | $ 1.6 |
| Dividends declared and not paid | $ 26.8 | $ 0.0 |

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

**TECO ENERGY, INC.**
**NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS**
**UNAUDITED**

## 1. Summary of Significant Accounting Policies

See TECO Energy, Inc.'s 2015 Annual Report on Form 10-K for a complete discussion of the company's accounting policies. The significant accounting policies for all utility and diversified operations include:

### Principles of Consolidation and Basis of Presentation

Intercompany balances and intercompany transactions have been eliminated in consolidation. In the opinion of management, the unaudited consolidated condensed financial statements include all adjustments that are of a recurring nature and necessary to state fairly the financial position of TECO Energy, Inc. and its subsidiaries as of June 30, 2016 and Dec. 31, 2015, and the results of operations and cash flows for the periods ended June 30, 2016 and 2015. The results of operations for the three and six months ended June 30, 2016 are not necessarily indicative of the results that can be expected for the entire fiscal year ending Dec. 31, 2016.

The use of estimates is inherent in the preparation of financial statements in accordance with U.S. GAAP. Actual results could differ from these estimates. The year-end consolidated condensed balance sheet data was derived from audited financial statements; however, this quarterly report on Form 10-Q does not include all year-end disclosures required for an annual report on Form 10-K by U.S. GAAP.

On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on Sept. 4, 2015. As a result of the Merger, Merger Sub merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera. See **Note 16** for further information.

### Revenues

As of June 30, 2016 and Dec. 31, 2015, unbilled revenues of $73.2 million and $81.1 million, respectively, are included in the "Receivables" line item on the Consolidated Condensed Balance Sheets.

### Accounting for Franchise Fees and Gross Receipt Taxes

Tampa Electric and PGS are allowed to recover certain costs from customers on a dollar-per-dollar basis 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 Condensed Statements of Income. Franchise fees and gross receipt taxes payable by Tampa Electric and PGS are included as an expense on the Consolidated Condensed Statements of Income in "Taxes, other than income". These amounts totaled $28.6 million and $56.5 million for the three and six months ended June 30, 2016, respectively, compared to $29.3 million and $56.6 million for the three and six months ended June 30, 2015, respectively.

NMGC is an agent in the collection and payment of franchise fees and gross receipt taxes and is not required by a tariff to present the amounts on a gross basis. Therefore, NMGC's franchise fees and gross receipt taxes are presented net with no line-item impact on the Consolidated Condensed Statements of Income.

## 2. New Accounting Pronouncements

### Change in Accounting Policy

*Presentation of Debt Issuance Costs*

In April 2015, the FASB issued guidance regarding the presentation of debt issuance costs on the balance sheet. Under the new guidance, an entity is required to present debt issuance costs as a direct deduction from the carrying amount of the related debt liability rather than as a deferred charge (i.e., as an asset) under current guidance. In August 2015, the FASB amended the guidance to include an SEC staff announcement that it will not object to a company presenting debt issuance costs related to line-of-credit arrangements as an asset, regardless of whether a balance is outstanding. This guidance became effective for the company beginning in 2016 and is required to be applied on a retrospective basis for all periods presented. As of June 30, 2016 and Dec. 31, 2015, the company classified $25.2 million and $27.7 million, respectively, of debt issuance costs, which do not include costs for line-of-credit arrangements, as a deduction in the "Long-term debt, less amount due within one year" line item on the company's Consolidated Condensed Balance Sheet (previously classified in the "Deferred charges and other assets" line item). The guidance did not affect the company's results of operations or cash flows.

*Stock Compensation*

In March 2016, the FASB issued guidance regarding employee share-based payment accounting. The guidance simplifies several aspects of the accounting for share-based payment transactions, including the income tax consequences, accounting for forfeitures, classification of awards as either equity or liability, and presentation on the statement of cash flows. This guidance will be required for the company beginning in 2017. As early adoption is permitted, the company adopted the standard as of Jan. 1, 2016. Each aspect has an accounting impact and was implemented as follows:

- Income tax consequences – Under the new guidance, the company will no longer recognize excess tax benefits and certain tax deficiencies in additional paid in capital. Instead, the company will recognize all excess tax benefits and tax deficiencies as income tax expense or benefit on the income statement. In addition, the guidance eliminates the requirement that excess tax benefits be realized before the company can recognize them. Accordingly, the company recorded a $2.6 million cumulative adjustment to retained earnings as of Jan. 1, 2016 for excess tax benefits related to prior periods. In accordance with the new guidance, the company will no longer include excess tax benefits and tax deficiencies in the dilutive EPS calculation on a prospective basis.
- Accounting for forfeitures – The company's policy is to estimate the number of awards expected to be forfeited, which is consistent with prior periods.
- Classification of awards - The company had no share-based payments classified as liability awards as of June 30, 2016 or Dec. 31, 2015.
- Presentation on the statement of cash flows – Excess tax benefits are required to be presented as an operating activity on the statement of cash flows rather than as a financing activity. The change may be applied retrospectively or prospectively. The company elected to apply it prospectively, and prior periods were not retrospectively adjusted. Additionally, employee taxes paid by an employer to a tax authority when shares are withheld for tax-withholding purposes are required to be presented as a financing activity on a retrospective basis for all periods presented. Therefore, the company reclassified $1.3 million from operating activities to financing activities for the six months ended June 30, 2015.

**Future Accounting Pronouncements**

*Revenue from Contracts with Customers*

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The standard is principle-based and provides a five-step model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In addition, the guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. This guidance will be effective for the company beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. The company will adopt this guidance effective Jan. 1, 2018. The company has developed an implementation plan and is continuing to evaluate the available adoption methods and the impact of the adoption of this guidance on its financial statements, but does not expect the impact to be significant.

*Recognition and Measurement of Financial Assets and Financial Liabilities*

In January 2016, the FASB issued guidance related to accounting for financial instruments, including equity investments, financial liabilities under the fair value option, valuation allowances for available-for-sale debt securities, and the presentation and disclosure requirements for financial instruments. The company does not have equity investments or available-for-sale debt securities and it does not record financial liabilities under the fair value option. However, it is evaluating the impact of the adoption of this guidance on its financial statement disclosures, including those regarding the fair value of its long-term debt, but it does not expect the impact to be significant. The guidance will be effective for the company beginning in 2018.

*Leases*

In February 2016, the FASB issued guidance regarding the accounting for leases. The objective is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with a lease term of more than 12 months. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. Recognition of expenses for both operating and finance leases will be similar to existing guidance and as a result is expected to limit the impact of the changes on the income statement and statement of cash flows. In addition, the guidance will require additional disclosures regarding key information about leasing arrangements. This guidance will be effective for the company beginning in 2019, with early adoption permitted, and will be applied using a modified retrospective approach. The company is currently evaluating the impacts of the adoption of the guidance on its financial statements.

*Derivative Contract Novations*

In March 2016, the FASB issued guidance clarifying that a change in the counterparty to a derivative contract, in and of itself, does not require the dedesignation of a hedging relationship provided that all other hedge accounting criteria continue to be met. The guidance is effective for the company beginning in 2017, with early adoption permitted, and may be applied on a prospective or modified retrospective basis. The guidance will not affect the company's current financial statements. However, the company will assess the impact of this guidance on future derivative contract novations, if any.

*Measurement of Credit Losses on Financial Instruments*

In June 2016, the FASB issued guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. In addition, the guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. This guidance will be effective for the company beginning in 2020, with early adoption permitted in 2019, and will be applied using a modified retrospective approach. The company is currently evaluating the impacts of the adoption of the guidance on its financial statements.

## 3. Regulatory

Tampa Electric's retail business and PGS are regulated by the FPSC. Tampa Electric is also subject to regulation by the FERC. 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 requirement) equal to their cost of providing service, plus a reasonable return on invested capital.

NMGC is subject to regulation by the NMPRC. The NMPRC has jurisdiction over the regulatory matters related, directly and indirectly, to NMGC providing service to its customers, including, among other things, rates, accounting procedures, securities issuances, and standards of service. NMGC must follow certain accounting guidance that pertains specifically to entities that are subject to such regulation. Comparable to the FPSC, the NMPRC sets rates at a level that allows utilities such as NMGC to collect total revenues (revenue requirement) equal to their cost of providing service, plus a reasonable return on invested capital.

### Regulatory Assets and Liabilities

Tampa Electric, PGS and NMGC 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; 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; and the advance recovery of expenditures for approved costs such as future storm damage or the future removal of property. All regulatory assets are recovered through the regulatory process.

Details of the regulatory assets and liabilities are presented in the following table:

**Regulatory Assets and Liabilities**

| *(millions)* | *June 30, 2016* | *Dec. 31, 2015* |
|---|---|---|
| **Regulatory assets:** | | |
| Regulatory tax asset [1] | $ 80.8 | $ 74.7 |
| Cost-recovery clauses - deferred balances [2] | 2.5 | 5.5 |
| Cost-recovery clauses - offsets to derivative liabilities [2] | 1.1 | 26.5 |
| Environmental remediation [3] | 54.6 | 54.0 |
| Postretirement benefits [4] | 236.2 | 240.6 |
| Deferred bond refinancing costs [5] | 7.4 | 6.5 |
| Debt basis adjustment [6] | 15.8 | 17.5 |
| Competitive rate adjustment [2] | 2.5 | 2.6 |
| Other | 10.4 | 12.1 |
| Total regulatory assets | 411.3 | 440.0 |
| Less: Current portion | 18.4 | 44.8 |
| Long-term regulatory assets | $ 392.9 | $ 395.2 |
| **Regulatory liabilities:** | | |
| Regulatory tax liability | $ 7.3 | $ 7.9 |
| Cost-recovery clauses [2] | 98.0 | 55.9 |
| Transmission and delivery storm reserve | 56.1 | 56.1 |
| Accumulated reserve - cost of removal [7] | 678.6 | 679.9 |
| Other | 13.9 | 0.8 |
| Total regulatory liabilities | 853.9 | 800.6 |
| Less: Current portion | 130.1 | 84.8 |
| Long-term regulatory liabilities | $ 723.8 | $ 715.8 |

(1) The regulatory tax asset is primarily associated with the depreciation and recovery of AFUDC-equity. This asset does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be recovered over the expected life of the related assets.
(2) These assets and liabilities are related to FPSC and NMPRC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC or NMPRC, as applicable, on a dollar-for-dollar basis in the next year. In the case of the regulatory asset related to derivative liabilities, recovery occurs in the year following the settlement of the derivative position.
(3) This asset is related to costs associated with environmental remediation primarily at manufactured gas plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is impacted by the timing of the expenditures related to remediation.
(4) This asset is related to the deferred costs of postretirement benefits. It is included in rate base and earns a rate of return as permitted by the FPSC or NMPRC, as applicable. It is amortized over the remaining service life of plan participants.
(5) This asset represents the past costs associated with refinancing debt. It does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be amortized over the term of the related debt instruments.
(6) This asset represents the difference between the fair value and pre-merger carrying amounts for NMGC's long-term debt on the acquisition date. It does not earn a return and is not included in the regulatory capital structure. It is amortized over the term of the related debt instrument.
(7) This item represents the non-ARO cost of removal in the accumulated reserve for depreciation. AROs are costs for legally required removal of property, plant and equipment. Non-ARO cost of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment, net of salvage value upon retirement, which reduces rate base for ratemaking purposes. This liability is reduced as costs of removal are incurred.

**4. Income Taxes**

The effective tax rate increased to 43.10% for the six months ended June 30, 2016 from 39.09% for the same period in 2015 primarily due to non-deductible Merger transaction costs offset by the tax benefit related to long-term incentive compensation (see **Notes 2 and 16** for further description).

The company's subsidiaries join in the filing of a U.S. federal consolidated income tax return. The IRS concluded its examination of the company's 2014 consolidated federal income tax return in December 2015. The U.S. federal statute of limitations remains open for the year 2012 and forward. Years 2015 and 2016 are currently under examination by the IRS under its Compliance Assurance Program (CAP). Due to the Merger with Emera, the company is only eligible to participate in the CAP through its short tax year ending June 30, 2016. U.S. state jurisdictions have statutes of limitations generally ranging from three to four years from the filing of an income tax return. Additionally, any state net operating losses that were generated in prior years and are still being utilized are subject to examination by state jurisdictions. 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 and foreign jurisdictions include 2005 and forward. TECO Energy does not expect the settlement of audit examinations to significantly change the total amount of unrecognized tax benefits by the end of 2016.

**5. Employee Postretirement Benefits**

Included in the table below is the periodic expense for pension and other postretirement benefits offered by the company. Amounts disclosed for pension benefits include the amounts related to the qualified pension plan and the non-qualified, non-contributory SERP.

**Pension Expense**

| *(millions)* | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| *Three months ended June 30,* | *2016* | *2015* | *2016* | *2015* |
| **Components of net periodic benefit expense** | | | | |
| Service cost | $ 4.6 | $ 6.4 | $ 0.4 | $ 0.5 |
| Interest cost | 8.3 | 8.7 | 2.2 | 2.1 |
| Expected return on assets | (11.4) | (12.5) | (0.3) | (0.2) |
| Amortization of: | | | | |
| Prior service (benefit) cost | 0.2 | 0.0 | (0.7) | (0.6) |
| Actuarial loss | 3.5 | 4.8 | 0.0 | 0.0 |
| Regulatory asset | 0.0 | 0.0 | 0.3 | 0.2 |
| Curtailment cost | 1.3 | 0.0 | 0.0 | 0.0 |
| Settlement cost | 0.6 | 0.0 | 0.0 | 0.0 |
| Net pension expense recognized in the TECO Energy Consolidated Condensed Statements of Income | $ 7.1 | $ 7.4 | $ 1.9 | $ 2.0 |
| *Six months ended June 30,* | | | | |
| **Components of net periodic benefit expense** | | | | |
| Service cost | $ 9.0 | $ 10.9 | $ 0.9 | $ 1.1 |
| Interest cost | 16.4 | 16.1 | 4.4 | 4.1 |
| Expected return on assets | (22.7) | (23.3) | (0.6) | (0.5) |
| Amortization of: | | | | |
| Prior service (benefit) cost | 0.2 | (0.1) | (1.3) | (1.2) |
| Actuarial loss | 6.9 | 8.2 | 0.0 | 0.0 |
| Regulatory asset | 0.0 | 0.0 | 0.5 | 0.5 |
| Curtailment cost | 1.3 | 0.0 | 0.0 | 0.0 |
| Settlement cost | 0.6 | 0.0 | 0.0 | 0.0 |
| Net pension expense recognized in the TECO Energy Consolidated Condensed Statements of Income | $ 11.7 | $ 11.8 | $ 3.9 | $ 4.0 |

For the 2016 plan year, TECO Energy is using an assumed long-term EROA of 7.00% and a discount rate of 4.685% for pension benefits under its qualified pension plan. For the Jan. 1, 2016 measurement of TECO Energy's other postretirement benefits, TECO Energy assumed a discount rate of 4.667% for the Florida-based plan and 4.687% for the NMGC plan. Additionally, TECO Energy made contributions of $15.6 million and $24.5 million to its pension plan for the six months ended June 30, 2016 and 2015, respectively.

For the three and six months ended June 30, 2016, TECO Energy and its subsidiaries reclassified $0.2 million and $1.0 million, respectively, of pretax unamortized prior service benefit and actuarial losses from AOCI to net income as part of periodic benefit expense, compared with $1.4 million and $2.2 million for the three and six months ended June 30, 2015, respectively. In addition, during the three and six months ended June, 2016, the regulated companies reclassified $3.1 million and $5.3 million, respectively, of unamortized prior service benefit and actuarial losses from regulatory assets to net income as part of periodic benefit expense, compared with $3.0 million and $5.2 million for the three and six months ended June 30, 2015, respectively.

The settlement cost recognized relates to the settlement of the SERP liability for the TECO Coal participant. An estimated curtailment loss for the SERP of $1.3 million was recognized in the second quarter of 2016 as a result of retirements expected in the third quarter of 2016 due to the Merger.

The company's postretirement benefit plans were not explicitly impacted by the Merger. However, TECO Energy expects to recognize a settlement charge related to the SERP of approximately $8.0 million in the first quarter of 2017 due to retirements that will take place as a result of the Merger.

**6. Short-Term Debt**

Details of the credit facilities and related borrowings are presented in the following table:

**Credit Facilities**

| | *June 30, 2016* | | | *Dec. 31, 2015* | | |
|---|---|---|---|---|---|---|
| *(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 | $ 0.0 | $ 0.5 | $ 325.0 | $ 0.0 | $ 0.5 |
| 3-year accounts receivable facility (3) | 150.0 | 123.0 | 0.0 | 150.0 | 61.0 | 0.0 |
| TECO Energy/TECO Finance: | | | | | | |
| 5-year facility (2)(4) | 300.0 | 90.0 | 0.0 | 300.0 | 163.0 | 0.0 |
| 1-year term facility (4)(5) | 400.0 | 400.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| New Mexico Gas Company: | | | | | | |
| 5-year facility (2) | 125.0 | 2.0 | 1.7 | 125.0 | 23.0 | 1.7 |
| **Total** | $ 1,300.0 | $ 615.0 | $ 2.2 | $ 900.0 | $ 247.0 | $ 2.2 |

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) Prior to Mar. 24, 2015, this was a 1-year facility. This 3-year facility matures Mar. 23, 2018.
(4) TECO Finance is the borrower and TECO Energy is the guarantor of this facility.
(5) This 1-year facility matures Mar. 14, 2017.

At June 30, 2016, these credit facilities required commitment fees ranging from 12.5 to 30.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at June 30, 2016 and Dec. 31, 2015 was 1.33% and 1.29%, respectively.

*TECO Energy/TECO Finance Credit Facility*

On Mar. 14, 2016, TECO Finance entered into a one-year, $400 million credit agreement. The credit agreement (i) has a maturity date of Mar. 14, 2017; (ii) contains customary representations and warranties, events of default, and financial and other covenants; and (iii) provides for interest to accrue at variable rates based on the London interbank deposit rate plus a margin, or, as an alternative to such interest rate, 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 one-month London interbank deposit rate plus 1.00%.

**7. Long-Term Debt**

*Fair Value of Long-Term Debt*

At June 30, 2016, total long-term debt had a carrying amount of $3,490.0 million and an estimated fair market value of $3,845.8 million. At Dec. 31, 2015, total long-term debt had a carrying amount of $3,822.5 million and an estimated fair market value of $4,061.6 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. The fair value of debt securities totaling $58.8 million is determined using Level 1 measurements; the fair value of the remaining debt securities is determined using Level 2 measurements (see **Note 13** for information regarding the fair value hierarchy).

*Purchase in Lieu of Redemption of Revenue Refunding Bonds*

On Mar. 19, 2008, the HCIDA remarketed $86.0 million HCIDA Pollution Control Revenue Refunding Bonds, Series 2006 (Non-AMT) (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 Mar. 19, 2008 to Mar. 15, 2012. On Mar. 15, 2012, TEC purchased in lieu of redemption the Series 2006 HCIDA Bonds. The Series 2006 HCIDA Bonds bore interest at a term rate of 1.875% per annum from Mar. 15, 2012 to Mar. 15, 2016. On Mar. 15, 2016, pursuant to the terms of the Loan and Trust Agreement governing the Series 2006 HCIDA Bonds, a mandatory tender occurred and a term rate of 2.00% per annum will apply from Mar. 15, 2016 to Mar. 15, 2020. The 2016 mandatory tender did not impact the Consolidated Condensed Balance Sheet. 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.

As of June 30, 2016, $232.6 million of bonds purchased in lieu of redemption, including the Series 2006 HCIDA Bonds described above, were held by the trustee at the direction of TEC to provide an opportunity to evaluate refinancing alternatives.

## 8. Other Comprehensive Income

TECO Energy reported the following OCI related to changes in the fair value of cash flow hedges, recognized cost due to curtailment and amortization of unrecognized benefit costs associated with the company's postretirement plans:

**Other Comprehensive Income**

| | *Three months ended June 30,* | | | *Six months ended June 30,* | | |
|---|---|---|---|---|---|---|
| *(millions)* | Gross | Tax | Net | Gross | Tax | Net |
| **2016** | | | | | | |
| Unrealized gain on cash flow hedges | $ 0.0 | $ 0.0 | $ 0.0 | $ 0.0 | $ 0.0 | $ 0.0 |
| Reclassification from AOCI to net income (1) | 0.3 | (0.1) | 0.2 | 0.7 | (0.3) | 0.4 |
| Gain on cash flow hedges | 0.3 | (0.1) | 0.2 | 0.7 | (0.3) | 0.4 |
| Amortization of unrecognized benefit costs and other (2) | (0.3) | 0.1 | (0.2) | 0.5 | (0.2) | 0.3 |
| Recognized cost due to curtailment (3) | 0.1 | 0.0 | 0.1 | 0.1 | 0.0 | 0.1 |
| Total other comprehensive income | $ 0.1 | $ 0.0 | $ 0.1 | $ 1.3 | $ (0.5) | $ 0.8 |
| **2015** | | | | | | |
| Unrealized gain on cash flow hedges | $ 4.0 | $ (1.4) | $ 2.6 | $ 4.3 | $ (1.5) | $ 2.8 |
| Reclassification from AOCI to net income (1) | 0.3 | (0.1) | 0.2 | 0.7 | (0.4) | 0.3 |
| Gain on cash flow hedges | 4.3 | (1.5) | 2.8 | 5.0 | (1.9) | 3.1 |
| Amortization of unrecognized benefit costs (2) | 1.6 | (0.6) | 1.0 | 2.5 | (0.9) | 1.6 |
| Total other comprehensive income | $ 5.9 | $ (2.1) | $ 3.8 | $ 7.5 | $ (2.8) | $ 4.7 |

(1) Related to interest rate contracts recognized in Interest expense.
(2) Related to postretirement benefits. See **Note 5** for additional information.
(3) Related to the estimated curtailment loss for the SERP. See **Note 5** for additional information.

**Accumulated Other Comprehensive Loss**

| *(millions)* | June 30, 2016 | Dec. 31, 2015 |
|---|---|---|
| Unamortized pension loss and prior service credit (1) | $ (33.6) | $ (34.2) |
| Unamortized other benefit gains, prior service costs and transition obligations (2) | 25.4 | 25.6 |
| Net unrealized losses from cash flow hedges (3) | (3.2) | (3.6) |
| Total accumulated other comprehensive loss | $ (11.4) | $ (12.2) |

(1) Net of tax benefit of $20.9 million and $21.5 million as of June 30, 2016 and Dec. 31, 2015, respectively.
(2) Net of tax expense of $15.8 million and $16.1 million as of June 30, 2016 and Dec. 31, 2015, respectively.
(3) Net of tax benefit of $2.0 million and $2.3 million as of June 30, 2016 and Dec. 31, 2015, respectively.

## 9. Earnings Per Share

| *(millions, except per share amounts)* | *For the three months ended June 30, 2016* | *2015* | *For the six months ended June 30, 2016* | *2015* |
|---|---|---|---|---|
| **Basic earnings per share** | | | | |
| Net income from continuing operations | $ 5.5 | $ 61.5 | $ 79.2 | $ 125.3 |
| Amount allocated to nonvested participating shareholders | (0.1) | (0.2) | (0.2) | (0.4) |
| Income before discontinued operations available to common shareholders - Basic | $ 5.4 | $ 61.3 | $ 79.0 | $ 124.9 |
| Income (loss) from discontinued operations, net | $ (0.2) | $ (49.7) | $ (0.1) | $ (55.5) |
| Amount allocated to nonvested participating shareholders | 0.0 | 0.0 | 0.0 | 0.0 |
| Income (loss) from discontinued operations available to common shareholders - Basic | $ (0.2) | $ (49.7) | $ (0.1) | $ (55.5) |
| Net income | $ 5.3 | $ 11.8 | $ 79.1 | $ 69.8 |
| Amount allocated to nonvested participating shareholders | (0.1) | (0.2) | (0.2) | (0.4) |
| Net income available to common shareholders - Basic | $ 5.2 | $ 11.6 | $ 78.9 | $ 69.4 |
| Average common shares outstanding - Basic | 234.3 | 233.0 | 234.1 | 232.9 |
| Earnings per share from continuing operations available to common shareholders - Basic | $ 0.03 | $ 0.26 | $ 0.34 | $ 0.53 |
| Earnings per share from discontinued operations available to common shareholders - Basic | $ 0.0 | $ (0.21) | $ 0.0 | $ (0.23) |
| **Earnings per share available to common shareholders - Basic** | **$ 0.03** | **$ 0.05** | **$ 0.34** | **$ 0.30** |
| **Diluted earnings per share** | | | | |
| Net income from continuing operations | $ 5.5 | $ 61.5 | $ 79.2 | $ 125.3 |
| Amount allocated to nonvested participating shareholders | (0.1) | (0.2) | (0.2) | (0.4) |
| Income before discontinued operations available to common shareholders - Diluted | $ 5.4 | $ 61.3 | $ 79.0 | $ 124.9 |
| Income (loss) from discontinued operations, net | $ (0.2) | $ (49.7) | $ (0.1) | $ (55.5) |
| Amount allocated to nonvested participating shareholders | 0.0 | 0.0 | 0.0 | 0.0 |
| Income (loss) from discontinued operations available to common shareholders - Diluted | $ (0.2) | $ (49.7) | $ (0.1) | $ (55.5) |
| Net income | $ 5.3 | $ 11.8 | $ 79.1 | $ 69.8 |
| Amount allocated to nonvested participating shareholders | (0.1) | (0.2) | (0.2) | (0.4) |
| Net income available to common shareholders - Diluted | $ 5.2 | $ 11.6 | $ 78.9 | $ 69.4 |
| Unadjusted average common shares outstanding - Diluted | 234.3 | 233.0 | 234.1 | 232.9 |
| Assumed conversion of stock options, unvested restricted stock, unvested RSUs and contingent performance shares, net | 1.2 | 0.6 | 1.3 | 0.6 |
| Average common shares outstanding - Diluted | 235.5 | 233.6 | 235.4 | 233.5 |
| Earnings per share from continuing operations available to common shareholders - Diluted | $ 0.03 | $ 0.26 | $ 0.34 | $ 0.53 |
| Earnings per share from discontinued operations available to common shareholders - Diluted | $ 0.0 | $ (0.21) | $ 0.0 | $ (0.23) |
| **Earnings per share available to common shareholders - Diluted** | **$ 0.03** | **$ 0.05** | **$ 0.34** | **$ 0.30** |
| Anti-dilutive shares | 0.0 | 0.4 | 0.3 | 0.3 |

**10. 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. The company believes the claims in which the company or a subsidiary of the company is a defendant in the pending actions described below are without merit and intends to defend the matters vigorously.

*Peoples Gas 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. 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, a suit was 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 and a PGS contractor involved in the project, seeking damages for his injuries. The suit remains pending, with a trial currently expected in October 2016. The company is unable at this time to estimate the possible loss or range of loss with respect to this matter. While the outcome of such proceeding is uncertain, management does not believe that its ultimate resolution will have a material adverse effect on the company's results of operations, financial condition or cash flows.

*New Mexico Gas Company Legal Proceedings*

In February 2011, NMGC experienced gas shortages due to weather-related interruptions of electric service, weather-related problems on the systems of various interstate pipelines and in gas fields that are the sources of gas supplied to NMGC, and high weather-driven usage. This gas supply disruption and high usage resulted in the declaration of system emergencies by NMGC causing involuntary curtailments of gas utility service to approximately 28,700 customers (residential and business).

In March 2011, a customer purporting to represent a class consisting of all "32,000 [sic] customers" who had their gas utility service curtailed during the early-February system emergencies filed a putative class action lawsuit against NMGC. In March 2011, the Town of Bernalillo, New Mexico, purporting to represent a class consisting of all "New Mexico municipalities and governmental entities who have suffered damages as a result of the natural gas utility shut off" also filed a putative class action lawsuit against NMGC, four of its officers, and John and Jane Does at NMGC. In July 2011, the plaintiff in the Bernalillo class action filed an amended complaint to add an additional plaintiff purporting to represent a class of all "similarly situated New Mexico private businesses and enterprises."

In September 2015, a settlement was reached with all the named plaintiff class representatives in both of the class actions. The settlements were on an individual basis and not a class basis.

In addition to the two settled class actions described above, 18 insurance carriers have filed two subrogation lawsuits for monies paid to their insureds as a result of the curtailment of natural gas service in February 2011. In January 2016, the judge entered summary judgment in favor of NMGC and all of the subrogation lawsuits were dismissed. The insurance carriers subsequently filed a timely appeal of the summary judgment. In late May 2016, a settlement was reached with all the named plaintiffs in the subrogation lawsuits.

The settlements are not material to the company's financial position as of June 30, 2016.

*Proceedings in connection with the Merger with Emera*

Twelve securities class action lawsuits were filed against the company and its directors by holders of TECO Energy securities following the announcement of the Emera transaction. Eleven suits were filed in the Circuit Court for the 13th Judicial Circuit, in and for Hillsborough County, Florida. They alleged that TECO Energy's board of directors breached its fiduciary duties in agreeing to the Merger Agreement and sought to enjoin the Merger. In addition, several of these suits alleged that one or more of TECO Energy, Emera and an Emera affiliate aided and abetted such alleged breaches. The securities class action lawsuits have been consolidated per court order. Since the consolidation, two of the complaints have been amended. One of those complaints has added a claim against the individual defendants for breach of fiduciary duty to disclose. The twelfth suit was filed in the Middle District of Florida Federal Court and has subsequently been voluntarily dismissed.

The company also received two separate shareholder demand letters from purported shareholders of the company. Both of these letters demanded that the company maximize shareholder value and remove alleged conflicts of interest as well as eliminate allegedly preclusive deal protection devices. One of the letters also demanded that the company refrain from consummating the transaction with Emera. Both of these demand letters have subsequently been withdrawn.

In November 2015, the parties to the lawsuits entered into a Memorandum of Understanding with the various shareholder plaintiffs to settle, subject to court approval, all of the pending shareholder lawsuits challenging the proposed Merger. As a result of the Memorandum of Understanding, the company made additional disclosures related to the proposed Merger in a proxy supplement. Subsequent to the Merger closing the parties are expected to enter into a formal settlement agreement in August, which will be filed with the Hillsborough Circuit Court Judge for approval. There can be no assurance that the parties will ultimately enter into a stipulation of settlement or that the court will approve the settlement even if the parties were to enter into a stipulation of settlement. While the outcome of such proceeding is uncertain, management does not believe that its ultimate resolution will have a material adverse effect on the company's results of operations, financial condition or cash flows.

*Claim in connection with the Sale of TECO Coal*

As discussed in **Note 15**, TECO Coal was sold on Sept. 21, 2015 to Cambrian. On Mar. 18, 2016, Cambrian delivered a notice of a purported claim to TECO Diversified asserting breach of certain representations, and fraud and willful misconduct in connection therewith, of the SPA. While the outcome of such matter is uncertain, management does not believe that its ultimate resolution will have a material adverse effect on the company's results of operations, financial condition or cash flows.

*TECO Guatemala Holdings, LLC v. The Republic of Guatemala*

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

On Apr. 18, 2014, Guatemala filed an application for annulment of the entire Award (or, alternatively, certain parts of the Award) pursuant to applicable ICSID rules.

Also on Apr. 18, 2014, TGH separately filed an application for partial annulment of the Award on the basis of certain deficiencies in the ICSID Tribunal's determination of the amount of TGH's damages.

On Apr. 5, 2016, an ICSID ad hoc Committee issued a decision in favor of TGH in the annulment proceedings. In its decision, the ad hoc Committee unanimously dismissed Guatemala's application for annulment of the award and upheld the original $21.1 million award, plus interest. In addition, the ad hoc Committee granted TGH's application for partial annulment of the award, and ordered Guatemala to pay certain costs relating to the annulment proceedings. Because the Tribunal's award of costs to TGH in its original arbitration was based on the Tribunal's assessment that TGH had prevailed on liability and Guatemala had partially prevailed on damages, and the latter finding was annulled by the ad hoc Committee, the Committee also annulled the Tribunal's award of costs to TGH. As a result, TGH has the right to resubmit its arbitration claim against Guatemala to seek additional damages (in addition to the previously awarded $21.1 million), as well as additional interest on the $21.1 million, and its full costs relating to the original arbitration and the new arbitration proceeding. Results to date do not reflect any benefit of this decision.

**PGS Compliance Matter**

In 2015, FPSC staff presented PGS with a summary of alleged safety rule violations, many of which were identified during PGS' implementation of an action plan it instituted as a result of audit findings cited by FPSC audit staff in 2013. Following the 2013 audit and 2015 discussions with FPSC staff, PGS took immediate and significant corrective actions. The FPSC audit staff published a follow-up audit report that acknowledged the progress that had been made and found that further improvements were needed. As a result of this report, the Office of Public Counsel (OPC) filed a petition with the FPSC pointing to the violations of rules for safety inspections seeking fines or possible refunds to customers by PGS. On Feb. 25, 2016, the FPSC staff issued a notice informing PGS that the staff would be making a recommendation to the FPSC to initiate a show cause proceeding against PGS for alleged safety rule violations, with total potential penalties of up to $3.9 million. On Apr. 18, 2016, PGS reached a settlement regarding this matter with the OPC and FPSC staff and agreed to pay a $1 million civil penalty and customer refunds of $2 million. The FPSC approved the settlement agreement on May 5, 2016.

**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 June 30, 2016, TEC has estimated its ultimate financial liability to be $33.9 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Deferred credits and other liabilities" 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 rates.

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.

**Merger Commitments**

In connection with the Merger with Emera, TECO Energy made certain commitments approved by the NMPRC. See **Note 16** for additional information.

**Guarantees and Letters of Credit**

A summary of the face amount or maximum theoretical obligation and the year of expiration under letters of credit and guarantees as of June 30, 2016 is as follows:

| *(millions)* | | | | Maximum | |
|---|---|---|---|---|---|
| *Guarantees for the Benefit of:* | *2016* | *2017-2020* | *After [1] 2020* | *Theoretical Obligation* | *Liabilities Recognized at June 30, 2016* |
| **TECO Energy** | | | | | |
| Fuel sales and transportation [2] | $ 0.0 | $ 0.0 | $ 93.9 | $ 93.9 | $ 0.0 |
| Letters of indemnity - coal mining permits [3] | 85.9 | 0.0 | 0.0 | 85.9 | 0.0 |
| | $ 85.9 | $ 0.0 | $ 93.9 | $ 179.8 | $ 0.0 |

| *(millions)* | | | | *Maximum* | |
|---|---|---|---|---|---|
| *Letters of Credit for the Benefit of:* | *2016* | *2017-2020* | *After [1] 2020* | *Theoretical Obligation* | *Liabilities Recognized at June 30, 2016 [4]* |
| **TEC** | $ 0.0 | $ 0.0 | $ 0.5 | $ 0.5 | $ 0.1 |
| **NMGC** | 0.0 | 0.0 | 1.7 | 1.7 | 0.8 |
| | $ 0.0 | $ 0.0 | $ 2.2 | $ 2.2 | $ 0.9 |

(1) These letters of credit and guarantees renew annually and are shown on the basis that they will continue to renew beyond 2020.

(2) The amounts shown represent the maximum theoretical amounts of cash collateral that TECO Energy would be required to post in the event of a downgrade below investment grade for its long-term debt ratings by the major credit rating agencies. Liabilities recognized represent the associated potential obligation related to net derivative liabilities under these agreements at June 30, 2016. See **Note 12** for additional information.

(3) These letters of indemnity guarantee payments to certain surety companies that issued reclamation bonds to the Commonwealths of Kentucky and Virginia in connection with TECO Coal's mining operations. Payments to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder, TECO Coal, does not pay the surety. The amounts shown represent the maximum theoretical amounts that TECO Energy would be required to pay to the surety companies. As discussed in **Note 15**, TECO Coal was sold on Sept. 21, 2015 to Cambrian. Pursuant to the SPA, Cambrian is obligated to file applications required in connection with the change of control with the appropriate governmental entities. Once the applicable governmental agency deems each application to be acceptable, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond secured by the TECO Energy indemnity for that permit. Until the bonds secured by TECO Energy's indemnity are released, TECO Energy's indemnity will remain effective. At the date of sale in September 2015, the letters of indemnity guaranteed $93.8 million. The company is working with Cambrian on the process to replace the bonds. Pursuant to the SPA, Cambrian has the obligation to indemnify and hold TECO Energy harmless from any losses incurred, subject to the indemnification terms set forth in the SPA, that arise out of the coal mining permits during the period commencing on the closing date through the date all permit approvals are obtained.

(4) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation of TECO Energy, TEC or NMGC under these agreements at June 30, 2016. The obligations under these letters of credit include certain accrued injuries and damages when a letter of credit covers the failure to pay these claims.

### Financial Covenants

In order to utilize their respective bank facilities, TECO Energy and its subsidiaries must meet certain financial tests, including a debt to capital ratio, as defined in the applicable agreements. In addition, TECO Energy and its subsidiaries have certain restrictive covenants in specific agreements and debt instruments. At June 30, 2016, TECO Energy and its subsidiaries were in compliance with all applicable financial covenants.

## 11. Segment Information

TECO Energy is an electric and gas utility holding company with 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. Intercompany transactions are eliminated in the Consolidated Condensed Financial Statements of TECO Energy, but are included in determining reportable segments.

**Segment Information [(1)]**

| *(millions)* *Three months ended June 30,* | Tampa Electric | Peoples Gas | New Mexico Gas Co. [(2)] | TECO Coal [(1)] | Other [(2)] | Eliminations | TECO Energy |
|---|---|---|---|---|---|---|---|
| **2016** | | | | | | | |
| Revenues - external | $ 498.1 | $ 99.9 | $ 51.7 | $ 0.0 | $ 2.6 | $ 0.0 | $ 652.3 |
| Sales to affiliates | 1.1 | 2.0 | 0.0 | 0.0 | 0.0 | (3.1) | 0.0 |
| Total revenues | 499.2 | 101.9 | 51.7 | 0.0 | 2.6 | (3.1) | 652.3 |
| Depreciation and amortization | 66.5 | 14.9 | 8.5 | 0.0 | 0.3 | 0.0 | 90.2 |
| Total interest charges | 22.6 | 3.7 | 3.3 | 0.0 | 14.5 | (0.3) | 43.8 |
| Internally allocated interest | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 | (0.3) | 0.0 |
| Provision (benefit) for income taxes | 36.9 | 4.6 | (0.1) | 0.0 | (17.1) | 0.0 | 24.3 |
| Net income (loss) from continuing operations | 68.6 | 7.1 | (0.2) | 0.0 | (70.0) [(5)] | 0.0 | 5.5 |
| Income (loss) from discontinued operations, net [(1)] | 0.0 | 0.0 | 0.0 | 0.0 | (0.2) | 0.0 | (0.2) |
| Net income (loss) | $ 68.6 | $ 7.1 | $ (0.2) | $ 0.0 | $ (70.2) | $ 0.0 | 5.3 |
| **2015** | | | | | | | |
| Revenues - external | $ 531.6 | $ 92.2 | $ 54.0 | $ 0.0 | $ 2.8 | $ 0.0 | $ 680.6 |
| Sales to affiliates | 0.8 | 1.3 | 0.0 | 0.0 | 0.1 | (2.2) | 0.0 |
| Total revenues | 532.4 | 93.5 | 54.0 | 0.0 | 2.9 | (2.2) | 680.6 |
| Depreciation and amortization | 64.0 | 14.0 | 8.4 | 0.0 | 0.6 | 0.0 | 87.0 |
| Total interest charges | 23.6 | 3.6 | 3.3 | 0.0 | 16.3 | (0.4) | 46.4 |
| Internally allocated interest | 0.0 | 0.0 | 0.0 | 0.0 | 0.4 | (0.4) | 0.0 |
| Provision (benefit) for income taxes | 38.9 | 4.8 | 0.0 | 0.0 | (3.2) | 0.0 | 40.5 |
| Net income (loss) from continuing operations | 67.7 | 7.6 | (0.1) | 0.0 | (13.7) | 0.0 | 61.5 |
| Income (loss) from discontinued operations, net [(1)] | 0.0 | 0.0 | 0.0 | (51.5) | 1.8 | 0.0 | (49.7) |
| Net income (loss) | $ 67.7 | $ 7.6 | $ (0.1) | $(51.5) | $ (11.9) | $ 0.0 | 11.8 |

| *(millions)* *Six months ended June 30,* | Tampa Electric | Peoples Gas | New Mexico Gas Co. [2] | TECO Coal [1] | Other [2] | Eliminations | TECO Energy |
|---|---|---|---|---|---|---|---|
| **2016** | | | | | | | |
| Revenues - external | $ 921.5 | $ 226.7 | $ 158.3 | $ 0.0 | $ 5.3 | $ 0.0 | $ 1,311.8 |
| Sales to affiliates | 2.2 | 6.4 | 0.0 | 0.0 | 0.0 | (8.6) | 0.0 |
| Total revenues | 923.7 | 233.1 | 158.3 | 0.0 | 5.3 | (8.6) | 1,311.8 |
| Depreciation and amortization | 132.6 | 29.7 | 16.9 | 0.0 | 0.8 | 0.0 | 180.0 |
| Total interest charges | 46.4 | 7.4 | 6.3 | 0.0 | 30.1 | (0.5) | 89.7 |
| Internally allocated interest | 0.0 | 0.0 | 0.0 | 0.0 | 0.5 | (0.5) | 0.0 |
| Provision (benefit) for income taxes | 64.7 | 13.5 | 9.6 | 0.0 | (27.8) | 0.0 | 60.0 |
| Net income (loss) from continuing operations | 118.8 | 20.2 | 15.0 | 0.0 | (74.8) [5] | 0.0 | 79.2 |
| Income (loss) from discontinued operations, net [1] | 0.0 | 0.0 | 0.0 | 0.0 | (0.1) | 0.0 | (0.1) |
| Net income (loss) | $ 118.8 | $ 20.2 | $ 15.0 | $ 0.0 | $ (74.9) | $ 0.0 | $ 79.1 |
| **2015** | | | | | | | |
| Revenues - external | $ 981.4 | $ 213.9 | $ 173.0 | $ 0.0 | $ 5.3 | $ 0.0 | $ 1,373.6 |
| Sales to affiliates | 1.6 | 2.5 | 0.0 | 0.0 | 0.1 | (4.2) | 0.0 |
| Total revenues | 983.0 | 216.4 | 173.0 | 0.0 | 5.4 | (4.2) | 1,373.6 |
| Depreciation and amortization | 126.9 | 27.9 | 16.8 | 0.0 | 0.9 | 0.0 | 172.5 |
| Total interest charges | 47.1 | 7.1 | 6.6 | 0.0 | 34.2 | (0.7) | 94.3 |
| Internally allocated interest | 0.0 | 0.0 | 0.0 | 0.0 | 0.7 | (0.7) | 0.0 |
| Provision (benefit) for income taxes | 66.3 | 14.0 | 9.0 | 0.0 | (8.9) | 0.0 | 80.4 |
| Net income (loss) from continuing operations | 115.9 | 22.2 | 13.8 | 0.0 | (26.6) | 0.0 | 125.3 |
| Income (loss) from discontinued operations, net [1] | 0.0 | 0.0 | 0.0 | (57.5) | 2.0 | 0.0 | (55.5) |
| Net income (loss) | $ 115.9 | $ 22.2 | $ 13.8 | $(57.5) | $ (24.6) | $ 0.0 | $ 69.8 |
| **At June 30, 2016** | | | | | | | |
| Total assets | $ 7,103.4 | $ 1,135.9 | $ 1,200.9 | $ 0.0 | $ 1,945.8 | $ (2,306.3) [4] | 9,079.7 |
| **At Dec. 31, 2015** | | | | | | | |
| Total assets [3] | $ 7,003.8 | $ 1,136.1 | $ 1,229.7 | $ 0.0 | $ 1,945.1 | $ (2,381.2) [4] | 8,933.5 |

(1) All periods have been adjusted to reflect the results from operations to discontinued operations for TECO Coal and certain charges and gains at Other, including Parent and TECO Diversified, that directly relate to TECO Coal and TECO Guatemala. See **Note 15**.
(2) NMGI is included in the Other segment.
(3) Certain prior year amounts have been reclassified to conform to current year presentation.
(4) Amounts primarily relate to intercompany advances and consolidated tax eliminations.
(5) Comprised primarily of transaction costs associated with the Merger with Emera. See **Note 16.**

**12. 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, PGS and NMGC;
- To optimize the utilization of NMGC's physical natural gas storage capacity, and
- To limit the exposure to interest rate fluctuations on debt securities at TECO Energy and its affiliates.

TECO Energy and its affiliates use derivatives only to reduce normal operating and market risks, not for speculative purposes. The regulated utilities' 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 13**). 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 and sale of natural gas for the benefit of its regulated companies' ratepayers. These standards, in accordance with the FPSC and NMPRC, 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 June 30, 2016, all of the company's physical contracts qualify for the NPNS exception with the exception of a minor amount of forward purchases and sales entered into by NMGC to optimize its gas storage capacity.

The derivatives that are designated as cash flow hedges at June 30, 2016 and Dec. 31, 2015 are reflected on the company's Consolidated Condensed Balance Sheets and classified accordingly as current and long-term assets and liabilities on a net basis as permitted by their respective master netting agreements. Derivative assets totaled $5.5 million and $0.2 million as of June 30, 2016 and Dec. 31, 2015, respectively. Derivative liabilities totaled $1.1 million and $26.2 million as of June 30, 2016 and Dec. 31, 2015, respectively. There are minor offset amount differences between the gross derivative assets and liabilities and the net amounts presented on the Consolidated Condensed Balance Sheets. There was no cash collateral posted with or received from any counterparties.

All of the derivative assets and liabilities at June 30, 2016 and Dec. 31, 2015 are designated as hedging instruments, which primarily are derivative hedges of natural gas contracts to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers. The corresponding effect of these natural gas related derivatives on the regulated utilities' fuel recovery clause mechanism is reflected on the Consolidated Condensed Balance Sheets as current and long-term regulatory assets and liabilities. Based on the fair value of the instruments at June 30, 2016, net pretax losses of $3.0 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Condensed Statements of Income within the next twelve months.

The June 30, 2016 and Dec. 31, 2015 balance in AOCI related to the cash flow hedges and interest rate swaps (unsettled and previously settled) is presented in **Note 8**.

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 three and six months ended June 30, 2016 and 2015, all hedges were effective. The derivative after-tax effect on OCI and the amount of after-tax gain or loss reclassified from AOCI into earnings for the three and six months ended June 30, 2016 and 2015 is presented in **Note 8**. These gains and losses were the result of interest rate contracts for TEC. The location of the reclassification to income was reflected in “Interest expense” for TEC.

The maximum length of time over which the company is hedging its exposure to the variability in future cash flows extends to June 30, 2018 for financial natural gas contracts. The following table presents the company’s derivative volumes that, as of June 30, 2016, are expected to settle during the 2016, 2017 and 2018 fiscal years:

| **Derivative Volumes** *(millions)* | Natural Gas Contracts (MMBTUs) | |
|---|---|---|
| Year | Physical | Financial |
| 2016 | 0.0 | 19.3 |
| 2017 | 0.0 | 17.7 |
| 2018 | 0.0 | 2.6 |
| Total | 0.0 | 39.6 |

The company is exposed to credit risk by 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. 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 June 30, 2016, 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 generally do not require a nonperformance risk adjustment 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.

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 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.

## 13. Fair Value Measurements

### Items Measured at Fair Value on a Recurring Basis

Accounting guidance governing fair value measurements and disclosures provides that fair value represents the amount that would be received in selling an asset or the amount that would be paid in transferring a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that is determined based upon assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, accounting guidance also establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1: Observable inputs, such as quoted prices in active markets;

Level 2: Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and

Level 3: Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities are measured at fair value based on one or more of the following three valuation techniques noted under accounting guidance:

(A) *Market approach*: Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities;

(B) *Cost approach:* Amount that would be required to replace the service capacity of an asset (replacement cost); and

(C) *Income approach:* Techniques to convert future amounts to a single present amount based upon market expectations (including present value techniques, option-pricing and excess earnings models).

The fair value of financial instruments is determined by using various market data and other valuation techniques.

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 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.

**Recurring Fair Value Measures**

| | *As of June 30, 2016* | | | |
|---|---|---|---|---|
| *(millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | |
| Natural gas derivatives | $ 0.0 | $ 5.5 | $ 0.0 | $ 5.5 |
| **Liabilities** | | | | |
| Natural gas derivatives | $ 0.0 | $ 1.1 | $ 0.0 | $ 1.1 |

| | *As of Dec. 31, 2015* | | | |
|---|---|---|---|---|
| *(millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | |
| Natural gas derivatives | $ 0.0 | $ 0.2 | $ 0.0 | $ 0.2 |
| **Liabilities** | | | | |
| Natural gas derivatives | $ 0.0 | $ 26.2 | $ 0.0 | $ 26.2 |

The natural gas derivatives are OTC swap, forward and option instruments. Fair values of swaps and forwards are estimated utilizing the market approach. The price of swaps and forwards are calculated using observable NYMEX quoted closing prices of exchange-traded futures. Fair values of options are estimated utilizing the income approach. The price of options is calculated using the Black-Scholes model with observable exchange-traded futures as the primary pricing inputs to the model. Additional inputs to the model include historical volatility, discount rate, and a locational basis adjustment to NYMEX. The resulting prices are applied to the notional quantities of active swap, forward and option positions to determine the fair value (see **Note 12**).

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 June 30, 2016, the fair value of derivatives was not materially affected by nonperformance risk. There were no Level 3 assets or liabilities for the periods presented.

As of June 30, 2016 and Dec. 31, 2015, the carrying value of the company's short-term debt is not materially different from the fair value due to the short-term nature of the instruments and because the stated rates approximate market rates. The fair value is determined using Level 2 measurements. See **Note 7** for information regarding the fair value of the company's long-term debt.

### 14. 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.

Tampa Electric 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 250 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 variable interests. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. Tampa Electric 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, and have the obligation or right to absorb losses or benefits. As a result, Tampa Electric is not the primary beneficiary and is not required to consolidate any of these entities. Tampa Electric purchased $16.4 million and $29.0 million under these PPAs for the three and six months ended June 30, 2016, respectively, and $9.9 million and $15.3 million for the three and six months ended June 30, 2015, respectively.

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 Condensed Balance Sheets, Statements of Income or Cash Flows.

### 15. Discontinued Operations and Asset Impairments

*TECO Coal*

On Sept. 21, 2015, TECO Energy's subsidiary, TECO Diversified, entered into an SPA and completed the sale of all of its ownership interest in TECO Coal to Cambrian. The SPA did not provide for an up-front purchase payment, but provides for future contingent consideration of up to $60 million that may be paid yearly through 2019 if certain coal benchmark prices reach certain levels. The 2015 benchmark price was not reached and no contingent consideration payment was triggered. TECO Energy retains certain deferred tax assets and personnel-related liabilities, but all other TECO Coal assets and liabilities, including working capital, asset retirement obligations and workers compensation reserves, were transferred in the transaction. Letters of indemnity related to TECO Coal reclamation bonds will remain in effect until the bonds are replaced by Cambrian, which is expected to be completed in 2016 (see description of guarantees in **Note 10**). The SPA contained customary representations, warranties and covenants (see **Note 10** for description of a claim related to the SPA). The income shown for 2016 in the table below reflects a refund of prepaid costs.

Since the closing of the sale, TECO Energy has not had influence over operations of TECO Coal, therefore the contingent payments are not considered to meet the definition of direct cash flows under the applicable discontinued operations FASB guidance.

*TECO Guatemala*

In 2012, TECO Guatemala completed the sale of its interests in the Alborada and San José power stations, and related solid fuel handling and port facilities in Guatemala. All periods presented reflect the classification of results from operations for TECO Guatemala and certain charges at Parent that directly relate to TECO Guatemala as discontinued operations. While TECO Energy and its subsidiaries 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 (see **Note 10**). The charges shown in the table below are legal costs associated with that claim.

***Combined Components of Discontinued Operations***

The following table provides selected components of discontinued operations related to the sales of TECO Coal and TECO Guatemala:

| **Components of income from discontinued operations** | *Three months ended June 30,* | | *Six months ended June 30,* | |
|---|---|---|---|---|
| *(millions)* | *2016* | *2015* | *2016* | *2015* |
| Revenues—TECO Coal | $ 0.0 | $ 76.1 | $ 0.0 | $ 148.8 |
| Income (loss) from operations—TECO Coal | (0.3) | 0.5 | (0.1) | (9.0) |
| Loss on impairment—TECO Coal | 0.0 | (78.6) | 0.0 | (78.6) |
| Loss from operations—TECO Guatemala | (0.1) | 0.0 | (0.1) | (0.1) |
| Loss from discontinued operations—TECO Coal | (0.3) | (78.1) | (0.1) | (87.6) |
| Loss from discontinued operations—TECO Guatemala | (0.1) | 0.0 | (0.1) | (0.1) |
| Loss from discontinued operations | (0.4) | (78.1) | (0.2) | (87.7) |
| Benefit for income taxes | (0.2) | (28.4) | (0.1) | (32.2) |
| Loss from discontinued operations, net | $ (0.2) | $ (49.7) | $ (0.1) | $ (55.5) |

## 16. Mergers and Acquisitions

### Merger with Emera Inc.

***Description of Transaction***

On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on Sept. 4, 2015. As a result of the Merger, Merger Sub merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera.

Pursuant to the Merger Agreement, upon the closing of the Merger, each issued and outstanding share of TECO Energy common stock was cancelled and converted automatically into the right to receive $27.55 in cash, without interest (Merger Consideration). This represents an aggregate purchase price of approximately $10.7 billion including Emera's purchase price allocation for debt of approximately $4.2 billion.

The Merger Agreement requires Emera, among other things, (i) to maintain TECO Energy's historic levels of community involvement and charitable contributions and support in TECO Energy's existing service territories, (ii) to maintain TECO Energy's headquarters in Tampa, Florida, (iii) to honor current union contracts in accordance with their terms and (iv) to provide each continuing non-union employee, for a period of two years following the closing of the Merger, with a base salary or wage rate no less favorable than, and incentive compensation and employee benefits, respectively, substantially comparable in the aggregate to those that they received as of immediately prior to the closing.

***Merger-Related Regulatory Matters***

On Apr. 11, 2016, Emera and TECO Energy filed with the NMPRC an unopposed stipulation agreement reflecting a settlement reached with certain intervening parties in the then pending proceeding seeking the approval of the Merger by the NMPRC. On May 2, 2016, the Hearing Examiner held a hearing to consider the stipulation agreement. On June 8, 2016, the Hearing Examiner filed a Certificate of Stipulation, recommending approval by the NMPRC of the stipulation with respect to which all intervenors had either consented or filed a notice of non-opposition. On June 22, 2016, the NMPRC approved the stipulation, and an order was entered on that same day.

As part of the stipulation agreement filed with the NMPRC noted above, upon closing of the Merger, NMGC agreed, among other things, to:

- make commitments to charitable contributions and enterprises engaged in economic and business development in New Mexico of $0.8 million annually for three years,
- continue to provide an annual bill reduction credit of $4 million through June 30, 2018,
- evaluate and construct, at shareholder expense, an enlarged pipeline from its current system to the New Mexico/Mexican border at an estimated cost of approximately $5 million,
- establish, at shareholder expense, a matching fund of $10 million to extend its natural gas infrastructure to currently underserved or unserved areas in New Mexico, and
- contribute, at shareholder expense, $5 million within 5 years to economic development projects or programs throughout New Mexico.

The preceding pretax costs of up to $30.4 million (or approximately $18.5 million after tax) will be recorded in the third quarter of 2016 in the Consolidated Condensed Statements of Income.

***Transaction-Related Costs***

During the three and six months ended June 30, 2016, TECO Energy incurred approximately $71.4 million and $71.5 million, respectively, of pretax incremental transaction-related costs ($58.4 million after tax for the three months ended June 30, 2016), which are presented in "Merger transaction-related costs" on the Consolidated Condensed Statements of Income. For the three months ended June 30, 2016, these costs include $27.7 million of investment banking, legal and other consultant costs, $42.4 million for change-in-control and other compensation payments, and $1.3 million for a non-cash SERP curtailment charge. These costs are expected to be primarily paid in the third quarter of 2016 and the first quarter of 2017. The company will record $15.2 million in the third quarter of 2016, primarily for accelerated vesting of outstanding stock-based compensation awards in accordance with the Merger Agreement which will be paid in the third quarter of 2016.

See **Notes 4 and 5** for information regarding impacts to the company's taxes and employee postretirement benefits, respectively, as a result of the Merger.

***Dividends Paid***

On June 22, 2016, in preparation for the Merger with Emera and in accordance with the Merger Agreement, the TECO Energy board of directors declared a special pro-rated dividend at the then-current rate of $0.002527 per share per day that accrued from May 16, 2016 (the prior TECO Energy dividend record date) until and including June 30, 2016 (the day prior to the effective day of the Merger). This dividend was accrued on the company’s Consolidated Condensed Balance Sheet as of June 30, 2016. On July 12, 2016, TECO Energy paid the dividends of $26.8 million to shareholders of record as of the close of business on the last trading day prior to the effective date of the Merger.

**17. Subsequent Events**

On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on Sept. 4, 2015. As a result of the Merger, Merger Sub merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera. See **Note 16** for further information.

**TAMPA ELECTRIC COMPANY**
**Consolidated Condensed Balance Sheets**
**Unaudited**

| *Assets* *(millions)* | *June 30, 2016* | *Dec. 31, 2015* |
|---|---|---|
| **Property, plant and equipment** | | |
| Utility plant in service | | |
| Electric | $ 7,419.5 | $ 7,270.3 |
| Gas | 1,447.0 | 1,398.6 |
| Construction work in progress | 832.1 | 771.1 |
| Utility plant in service, at original costs | 9,698.6 | 9,440.0 |
| Accumulated depreciation | (2,762.0) | (2,676.8) |
| Utility plant in service, net | 6,936.6 | 6,763.2 |
| Other property | 10.2 | 9.7 |
| Total property, plant and equipment, net | 6,946.8 | 6,772.9 |
| | | |
| **Current assets** | | |
| Cash and cash equivalents | 13.8 | 9.1 |
| Receivables, less allowance for uncollectibles of $1.6 and $1.5 at June 30, 2016 and Dec. 31, 2015, respectively | 238.7 | 230.2 |
| Inventories, at average cost | | |
| Fuel | 102.2 | 105.6 |
| Materials and supplies | 75.1 | 73.1 |
| Regulatory assets | 18.0 | 44.3 |
| Taxes receivable from affiliate | 0.0 | 61.3 |
| Prepayments and other current assets | 20.6 | 21.5 |
| Total current assets | 468.4 | 545.1 |
| | | |
| **Deferred debits** | | |
| Regulatory assets | 373.8 | 373.8 |
| Other | 27.7 | 16.8 |
| Total deferred debits | 401.5 | 390.6 |
| **Total assets** | $ 7,816.7 | $ 7,708.6 |

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

**TAMPA ELECTRIC COMPANY**
**Consolidated Condensed Balance Sheets - continued**
**Unaudited**

| ***Liabilities and Capitalization*** *(millions)* | *June 30, 2016* | *Dec. 31, 2015* |
|---|---|---|
| **Capitalization** | | |
| Common stock | $ 2,395.4 | $ 2,305.4 |
| Accumulated other comprehensive loss | (3.2) | (3.6) |
| Retained earnings | 270.6 | 313.7 |
| Total capital | 2,662.8 | 2,615.5 |
| Long-term debt | 2,162.3 | 2,161.7 |
| Total capitalization | 4,825.1 | 4,777.2 |
| | | |
| **Current liabilities** | | |
| Long-term debt due within one year | 0.0 | 83.3 |
| Notes payable | 123.0 | 61.0 |
| Accounts payable | 209.5 | 221.6 |
| Customer deposits | 162.7 | 176.3 |
| Regulatory liabilities | 124.4 | 83.2 |
| Derivative liabilities | 0.7 | 24.1 |
| Interest accrued | 17.7 | 16.9 |
| Taxes accrued | 72.2 | 13.2 |
| Other | 10.0 | 10.2 |
| Total current liabilities | 720.2 | 689.8 |
| | | |
| **Deferred credits** | | |
| Deferred income taxes | 1,352.1 | 1,308.8 |
| Investment tax credits | 10.3 | 10.5 |
| Regulatory liabilities | 608.0 | 603.5 |
| Deferred credits and other liabilities | 301.0 | 318.8 |
| Total deferred credits | 2,271.4 | 2,241.6 |
| | | |
| **Commitments and Contingencies** (see **Note 8**) | | |
| | | |
| **Total liabilities and capitalization** | $ 7,816.7 | $ 7,708.6 |

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

## TAMPA ELECTRIC COMPANY
### Consolidated Condensed Statements of Income and Comprehensive Income
### Unaudited

| *(millions)* | *Three months ended June 30, 2016* | *2015* |
|---|---|---|
| **Revenues** | | |
| Electric | $ 498.8 | $ 532.4 |
| Gas | 100.0 | 92.2 |
| Total revenues | 598.8 | 624.6 |
| **Expenses** | | |
| Regulated operations and maintenance | | |
| Fuel | 137.4 | 171.8 |
| Purchased power | 27.8 | 19.6 |
| Cost of natural gas sold | 35.7 | 30.1 |
| Other | 132.5 | 134.3 |
| Depreciation and amortization | 81.4 | 78.0 |
| Taxes, other than income | 47.5 | 49.5 |
| Total expenses | 462.3 | 483.3 |
| **Income from operations** | 136.5 | 141.3 |
| **Other income** | | |
| Allowance for other funds used during construction | 6.0 | 3.7 |
| Other income, net | 0.9 | 1.2 |
| Total other income | 6.9 | 4.9 |
| **Interest charges** | | |
| Interest on long-term debt | 27.8 | 27.8 |
| Other interest | 1.2 | 1.2 |
| Allowance for borrowed funds used during construction | (2.8) | (1.8) |
| Total interest charges | 26.2 | 27.2 |
| **Income before provision for income taxes** | 117.2 | 119.0 |
| Provision for income taxes | 41.5 | 43.7 |
| **Net income** | 75.7 | 75.3 |
| **Other comprehensive income, net of tax** | | |
| Gain on cash flow hedges | 0.2 | 2.8 |
| Total other comprehensive income, net of tax | 0.2 | 2.8 |
| **Comprehensive income** | $ 75.9 | $ 78.1 |

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

**TAMPA ELECTRIC COMPANY**
**Consolidated Condensed Statements of Income and Comprehensive Income**
**Unaudited**

| *(millions)* | *Six months ended June 30, 2016* | *2015* |
|---|---|---|
| **Revenues** | | |
| Electric | $ 923.0 | $ 982.8 |
| Gas | 226.8 | 213.9 |
| Total revenues | 1,149.8 | 1,196.7 |
| **Expenses** | | |
| Regulated operations and maintenance | | |
| Fuel | 252.6 | 315.9 |
| Purchased power | 42.2 | 36.7 |
| Cost of natural gas sold | 86.0 | 73.4 |
| Other | 253.6 | 256.1 |
| Depreciation and amortization | 162.3 | 154.8 |
| Taxes, other than income | 96.0 | 97.1 |
| Total expenses | 892.7 | 934.0 |
| **Income from operations** | 257.1 | 262.7 |
| **Other income** | | |
| Allowance for other funds used during construction | 11.6 | 7.5 |
| Other income, net | 2.2 | 2.4 |
| Total other income | 13.8 | 9.9 |
| **Interest charges** | | |
| Interest on long-term debt | 56.8 | 55.5 |
| Interest expense | 2.4 | 2.3 |
| Allowance for borrowed funds used during construction | (5.5) | (3.6) |
| Total interest charges | 53.7 | 54.2 |
| **Income before provision for income taxes** | 217.2 | 218.4 |
| Provision for income taxes | 78.2 | 80.3 |
| **Net income** | 139.0 | 138.1 |
| **Other comprehensive income, net of tax** | | |
| Gain on cash flow hedges | 0.4 | 3.1 |
| Total other comprehensive income, net of tax | 0.4 | 3.1 |
| **Comprehensive income** | $ 139.4 | $ 141.2 |

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

## TAMPA ELECTRIC COMPANY
### Consolidated Condensed Statements of Cash Flows
### Unaudited

| *(millions)* | *Six months ended June 30, 2016* | *2015* |
|---|---|---|
| **Cash flows from operating activities** | | |
| Net income | $ 139.0 | $ 138.1 |
| Adjustments to reconcile net income to net cash from operating activities: | | |
| Depreciation and amortization | 162.3 | 154.8 |
| Deferred income taxes and investment tax credits | 36.5 | 30.0 |
| Allowance for funds used during construction | (11.6) | (7.5) |
| Deferred recovery clauses | 41.0 | (3.2) |
| Receivables, less allowance for uncollectibles | (8.5) | (24.4) |
| Inventories | 1.4 | (42.1) |
| Prepayments | 4.3 | (6.2) |
| Taxes accrued | 120.3 | 93.1 |
| Interest accrued | 0.8 | 2.0 |
| Accounts payable | 3.6 | (14.3) |
| Other | (25.9) | (14.9) |
| Cash flows from operating activities | 463.2 | 305.4 |
| **Cash flows from investing activities** | | |
| Capital expenditures | (353.8) | (312.4) |
| Net proceeds from sale of assets | 8.7 | 0.0 |
| Cash flows used in investing activities | (345.1) | (312.4) |
| **Cash flows from financing activities** | | |
| Common stock | 90.0 | 30.0 |
| Proceeds from long-term debt issuance | 0.0 | 251.3 |
| Repayment of long-term debt | (83.3) | (83.3) |
| Net decrease in short-term debt | 62.0 | (58.0) |
| Dividends | (182.1) | (109.5) |
| Cash flows from (used in) financing activities | (113.4) | 30.5 |
| **Net increase in cash and cash equivalents** | 4.7 | 23.5 |
| **Cash and cash equivalents at beginning of period** | 9.1 | 10.4 |
| **Cash and cash equivalents at end of period** | $ 13.8 | $ 33.9 |
| **Supplemental disclosure of non-cash activities** | | |
| Change in accrued capital expenditures | $ (13.9) | $ 1.5 |

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

**TAMPA ELECTRIC COMPANY**
**NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS**
**UNAUDITED**

## 1. Summary of Significant Accounting Policies

See TEC's 2015 Annual Report on Form 10-K for a complete discussion of accounting policies. The significant accounting policies for TEC include:

### Principles of Consolidation and Basis of Presentation

TEC is a wholly owned subsidiary of TECO Energy. For the purposes of its consolidated financial reporting, TEC is comprised of the electric division, generally referred to as Tampa Electric, the natural gas division, generally referred to as PGS, and potentially the accounts of VIEs for which it is the primary beneficiary. For the periods presented, no VIEs have been consolidated (see **Note 13**).

Intercompany balances and intercompany transactions have been eliminated in consolidation. In the opinion of management, the unaudited consolidated condensed financial statements include all adjustments that are of a recurring nature and necessary to state fairly the financial position of TEC as of June 30, 2016 and Dec. 31, 2015, and the results of operations and cash flows for the periods ended June 30, 2016 and 2015. The results of operations for the three and six months ended June 30, 2016 are not necessarily indicative of the results that can be expected for the entire fiscal year ending Dec. 31, 2016.

The use of estimates is inherent in the preparation of financial statements in accordance with U.S. GAAP. Actual results could differ from these estimates. The year-end consolidated condensed balance sheet data was derived from audited financial statements; however, this quarterly report on Form 10-Q does not include all year-end disclosures required for an annual report on Form 10-K by U.S. GAAP.

On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on Sept. 4, 2015. As a result of the Merger, Merger Sub merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera. See **Note 14** for further information.

### Revenues

As of June 30, 2016 and Dec. 31, 2015, unbilled revenues of $66.6 million and $53.7 million, respectively, are included in the "Receivables" line item on the Consolidated Condensed Balance Sheets.

### Accounting for Franchise Fees and Gross Receipts

Tampa Electric and PGS are allowed to recover certain costs from customers on a dollar-per-dollar basis 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 Condensed Statements of Income. Franchise fees and gross receipt taxes payable by Tampa Electric and PGS are included as an expense on the Consolidated Condensed Statements of Income in "Taxes, other than income". These amounts totaled $28.6 million and $56.5 million for the three and six months ended June 30, 2016, respectively, and $29.3 million and $56.6 million for the three and six months ended June 30, 2015, respectively.

## 2. New Accounting Pronouncements

### Change in Accounting Policy

*Presentation of Debt Issuance Costs*

In April 2015, the FASB issued guidance regarding the presentation of debt issuance costs on the balance sheet. Under the new guidance, an entity is required to present debt issuance costs as a direct deduction from the carrying amount of the related debt liability rather than as a deferred charge (i.e., as an asset) under current guidance. In August 2015, the FASB amended the guidance to include an SEC staff announcement that it will not object to a company presenting debt issuance costs related to line-of-credit arrangements as an asset, regardless of whether a balance is outstanding. This guidance became effective for TEC beginning in 2016 and is required to be applied on a retrospective basis for all periods presented. As of June 30, 2016 and Dec. 31, 2015, TEC classified $17.5 million and $18.1 million, respectively, of debt issuance costs, which do not include costs for line-of-credit arrangements, as a deduction in the "Long-term debt, less amount due within one year" line item on the company's Consolidated Condensed Balance Sheet (previously classified as an asset in the "Unamortized debt expense" line item). The guidance did not affect TEC's results of operations or cash flows.

**Future Accounting Pronouncements**

*Revenue from Contracts with Customers*

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. The standard is principle-based and provides a five-step model to determine when and how revenue is recognized. The core principle is that a company should recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. In addition, the guidance will require additional disclosures regarding the nature, amount, timing and uncertainty of revenue arising from contracts with customers. This guidance will be effective for TEC beginning in 2018, with early adoption permitted in 2017, and will allow for either full retrospective adoption or modified retrospective adoption. TEC will adopt this guidance effective Jan. 1, 2018. TEC has developed an implementation plan and is continuing to evaluate the available adoption methods and the impact of the adoption of this guidance on its financial statements, but does not expect the impact to be significant.

*Recognition and Measurement of Financial Assets and Financial Liabilities*

In January 2016, the FASB issued guidance related to accounting for financial instruments, including equity investments, financial liabilities under the fair value option, valuation allowances for available-for-sale debt securities, and the presentation and disclosure requirements for financial instruments. TEC does not have equity investments or available-for-sale debt securities and it does not record financial liabilities under the fair value option. However, it is evaluating the impact of the adoption of this guidance on its financial statement disclosures, including those regarding the fair value of its long-term debt, but it does not expect the impact to be significant. The guidance will be effective for TEC beginning in 2018.

*Leases*

In February 2016, the FASB issued guidance regarding the accounting for leases. The objective is to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet for leases with a lease term of more than 12 months. Under the existing guidance, operating leases are not recorded as lease assets and lease liabilities on the balance sheet. Recognition of expenses for both operating and finance leases will be similar to existing guidance and as a result is expected to limit the impact of the changes on the income statement and statement of cash flows. In addition, the guidance will require additional disclosures regarding key information about leasing arrangements. This guidance will be effective for TEC beginning in 2019, with early adoption permitted, and will be applied using a modified retrospective approach. TEC is currently evaluating the impacts of the adoption of the guidance on its financial statements.

*Derivative Contract Novations*

In March 2016, the FASB issued guidance clarifying that a change in the counterparty to a derivative contract, in and of itself, does not require the dedesignation of a hedging relationship provided that all other hedge accounting criteria continue to be met. The guidance is effective for TEC beginning in 2017, with early adoption permitted, and may be applied on a prospective or modified retrospective basis. The guidance will not affect TEC's current financial statements. However, TEC will assess the impact of this guidance on future derivative contract novations, if any.

*Measurement of Credit Losses on Financial Instruments*

In June 2016, the FASB issued guidance regarding the measurement of credit losses for financial assets and certain other instruments that are not accounted for at fair value through net income, including trade and other receivables, debt securities, net investment in leases, and off-balance sheet credit exposures. The new guidance requires companies to replace the current incurred loss impairment methodology with a methodology that measures all expected credit losses for financial assets based on historical experience, current conditions, and reasonable and supportable forecasts. In addition, the guidance expands the disclosure requirements regarding credit losses, including the credit loss methodology and credit quality indicators. This guidance will be effective for TEC beginning in 2020, with early adoption permitted in 2019, and will be applied using a modified retrospective approach. TEC is currently evaluating the impacts of the adoption of the guidance on its financial statements.

**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. 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 requirement) equal to their cost of providing service, plus a reasonable return on invested capital.

**Regulatory Assets and Liabilities**

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; 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; and the advance recovery of expenditures for approved costs such as future storm damage or the future removal of property. All regulatory assets are recovered through the regulatory process.

Details of the regulatory assets and liabilities are presented in the following table:

| Regulatory Assets and Liabilities<br>*(millions)* | | *June 30, 2016* | | *Dec. 31, 2015* |
|---|---|---|---|---|
| **Regulatory assets:** | | | | |
| Regulatory tax asset (1) | $ | 80.6 | $ | 74.6 |
| Cost-recovery clauses - deferred balances (2) | | 2.5 | | 5.2 |
| Cost-recovery clauses - offsets to derivative liabilities (2) | | 0.8 | | 26.2 |
| Environmental remediation (3) | | 54.6 | | 54.0 |
| Postretirement benefits (4) | | 234.3 | | 238.3 |
| Deferred bond refinancing costs (5) | | 6.1 | | 6.5 |
| Competitive rate adjustment (2) | | 2.5 | | 2.6 |
| Other | | 10.4 | | 10.7 |
| Total regulatory assets | | 391.8 | | 418.1 |
| Less: Current portion | | 18.0 | | 44.3 |
| Long-term regulatory assets | $ | 373.8 | $ | 373.8 |
| **Regulatory liabilities:** | | | | |
| Regulatory tax liability | $ | 5.3 | $ | 5.7 |
| Cost-recovery clauses (2) | | 92.5 | | 54.2 |
| Transmission and delivery storm reserve | | 56.1 | | 56.1 |
| Accumulated reserve - cost of removal (6) | | 564.7 | | 570.0 |
| Other | | 13.8 | | 0.7 |
| Total regulatory liabilities | | 732.4 | | 686.7 |
| Less: Current portion | | 124.4 | | 83.2 |
| Long-term regulatory liabilities | $ | 608.0 | $ | 603.5 |

(1) The regulatory tax asset is primarily associated with the depreciation and recovery of AFUDC-equity. This asset does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be recovered over the expected life of the related assets.

(2) These assets and liabilities are related to FPSC clauses and riders. They are recovered or refunded through cost-recovery mechanisms approved by the FPSC on a dollar-for-dollar basis in the next year. In the case of the regulatory asset related to derivative liabilities, recovery occurs in the year following the settlement of the derivative position.

(3) This asset is related to costs associated with environmental remediation primarily at manufactured gas plant sites. The balance is included in rate base, partially offsetting the related liability, and earns a rate of return as permitted by the FPSC. The timing of recovery is impacted by the timing of the expenditures related to remediation.

(4) This asset is related to the deferred costs of postretirement benefits. It is included in rate base and earns a rate of return as permitted by the FPSC. It is amortized over the remaining service life of plan participants.

(5) This asset represents the past costs associated with refinancing debt. It does not earn a return but rather is included in capital structure, which is used in the calculation of the weighted cost of capital used to determine revenue requirements. It will be amortized over the term of the related debt instruments.

(6) This item represents the non-ARO cost of removal in the accumulated reserve for depreciation. AROs are costs for legally required removal of property, plant and equipment. Non-ARO cost of removal represent estimated funds received from customers through depreciation rates to cover future non-legally required cost of removal of property, plant and equipment, net of salvage value upon retirement, which reduces rate base for ratemaking purposes. This liability is reduced as costs of removal are incurred.

### 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. TEC's effective tax rates for the six months ended June 30, 2016 and 2015 differ from the statutory rate principally due to the tax benefit related to AFUDC-equity.

The IRS concluded its examination of TECO Energy's 2014 consolidated federal income tax return in December 2015. The U.S. federal statute of limitations remains open for the year 2012 and forward. Years 2015 and 2016 are currently under examination by the IRS under its Compliance Assurance Program (CAP). Due to the Merger with Emera, TECO Energy is only eligible to participate in the CAP through its short tax year ending June 30, 2016. 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 2005 and forward as a result of TECO Energy's consolidated Florida net operating loss still being utilized. TEC does not expect the settlement of audit examinations to significantly change the total amount of unrecognized tax benefits by the end of 2016.

### 5. Employee Postretirement Benefits

TEC is a participant in the comprehensive retirement plans of TECO Energy. Amounts allocable to all participants of the TECO Energy retirement plans are found in **Note 5**, **Employee Postretirement Benefits**, in the **TECO Energy Notes to Consolidated Condensed Financial Statements**. TEC's portion of the net pension expense for the three months ended June 30, 2016 and 2015, respectively, was $3.2 million and $4.2 million for pension benefits, and $1.5 million and $1.5 million for other postretirement benefits. TEC's portion of the net pension expense for the six months ended June 30, 2016 and 2015, respectively, was $6.1 million and $6.8 million for pension benefits, and $3.0 million and $2.9 million for other postretirement benefits.

For the 2016 plan year, TECO Energy assumed a long-term EROA of 7.00% and a discount rate of 4.685%. For the Jan. 1, 2016 measurement of TECO Energy's other postretirement benefits, TECO Energy used a discount rate of 4.667%. Additionally, TECO Energy made contributions of $15.6 million and $24.5 million to its pension plan in the six months ended June 30, 2016 and 2015, respectively. TEC's portion of the contributions was $12.9 million and $18.5 million, respectively.

Included in the benefit expenses discussed above, for the three and six months ended June 30, 2016, TEC reclassified $2.8 million and $ 4.8 million, respectively, of unamortized prior service benefit and actuarial losses from regulatory assets to net income, compared with $2.8 million and $4.7 million for the three and six months ended June 30, 2015, respectively.

### 6. Short-Term Debt

Details of the credit facilities and related borrowings are presented in the following table:

**Credit Facilities**

| | *June 30, 2016* | | | *Dec. 31, 2015* | | |
|---|---|---|---|---|---|---|
| *(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 | $ 0.0 | $ 0.5 | $ 325.0 | $ 0.0 | $ 0.5 |
| 3-year accounts receivable facility (3) | 150.0 | 123.0 | 0.0 | 150.0 | 61.0 | 0.0 |
| **Total** | $ 475.0 | $ 123.0 | $ 0.5 | $ 475.0 | $ 61.0 | $ 0.5 |

(1) Borrowings outstanding are reported as notes payable.
(2) This 5-year facility matures Dec. 17, 2018.
(3) Prior to Mar. 24, 2015, this was a 1-year facility. This 3-year facility matures Mar. 23, 2018.

At June 30, 2016, these credit facilities required commitment fees ranging from 12.5 to 30.0 basis points. The weighted-average interest rate on outstanding amounts payable under the credit facilities at June 30, 2016 and Dec. 31, 2015 was 1.07% and 0.89%, respectively.

**7. Long-Term Debt**

*Fair Value of Long-Term Debt*

At June 30, 2016, TEC's total long-term debt had a carrying amount of $2,162.3 million and an estimated fair market value of $2,446.2 million. At Dec. 31, 2015, TEC's total long-term debt had a carrying amount of $2,245.0 million and an estimated fair market value of $2,433.3 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. The fair value of debt securities totaling $58.8 million is determined using Level 1 measurements; the fair value of the remaining debt securities is determined using Level 2 measurements (see **Note 11** for information regarding the fair value hierarchy).

*Purchase in Lieu of Redemption of Revenue Refunding Bonds*

On Mar. 19, 2008, the HCIDA remarketed $86.0 million HCIDA Pollution Control Revenue Refunding Bonds, Series 2006 (Non-AMT) (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 Mar. 19, 2008 to Mar. 15, 2012. On Mar. 15, 2012, TEC purchased in lieu of redemption the Series 2006 HCIDA Bonds. The Series 2006 HCIDA Bonds bore interest at a term rate of 1.875% per annum from Mar. 15, 2012 to Mar. 15, 2016. On Mar. 15, 2016, pursuant to the terms of the Loan and Trust Agreement governing the Series 2006 HCIDA Bonds, a mandatory tender occurred and a term rate of 2.00% per annum will apply from Mar. 15, 2016 to Mar. 15, 2020. The 2016 mandatory tender did not impact the Consolidated Condensed Balance Sheet. 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.

As of June 30, 2016, $232.6 million of bonds purchased in lieu of redemption, including the series 2006 HCIDA Bonds described above, were held by the trustee at the direction of TEC to provide an opportunity to evaluate refinancing alternatives.

**8. 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. The company believes the claims in the pending actions described below are without merit and intends to defend the matters vigorously.

*Peoples Gas 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. 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, a suit was 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 and a PGS contractor involved in the project, seeking damages for his injuries. The suit remains pending, with a trial currently expected in October 2016. The company is unable at this time to estimate the possible loss or range of loss with respect to this matter. While the outcome of such proceeding is uncertain, management does not believe that its ultimate resolution will have a material adverse effect on the company's results of operations, financial condition or cash flows.

**PGS Compliance Matter**

In 2015, FPSC staff presented PGS with a summary of alleged safety rule violations, many of which were identified during PGS' implementation of an action plan it instituted as a result of audit findings cited by FPSC audit staff in 2013. Following the 2013 audit and 2015 discussions with FPSC staff, PGS took immediate and significant corrective actions. The FPSC audit staff published a follow-up audit report that acknowledged the progress that had been made and found that further improvements were needed. As a result of this report, the Office of Public Counsel (OPC) filed a petition with the FPSC pointing to the violations of rules for safety inspections seeking fines or possible refunds to customers by PGS. On Feb. 25, 2016, the FPSC staff issued a notice informing PGS that the staff would be making a recommendation to the FPSC to initiate a show cause proceeding against PGS for alleged safety rule violations, with total potential penalties of up to $3.9 million. On Apr. 18, 2016, PGS reached a settlement regarding this matter with the OPC and FPSC staff and agreed to pay a $1 million civil penalty and customer refunds of $2 million. The FPSC approved the settlement agreement on May 5, 2016.

**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 June 30, 2016, TEC has estimated its ultimate financial liability to be $33.9 million, primarily at PGS. This amount has been accrued and is primarily reflected in the long-term liability section under "Deferred credits and other liabilities" 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 rates.

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.

**Letters of Credit**

A summary of the face amount or maximum theoretical obligation under TEC's letters of credit as of June 30, 2016 is as follows:

**Letters of Credit - Tampa Electric Company**

| *(millions)*<br>*Letters of Credit for the Benefit of:* | *2016* | *2017-2020* | *After [1] 2020* | *Total* | *Liabilities Recognized at June 30, 2016* |
|---|---|---|---|---|---|
| **TEC** [2] | $ 0.0 | $ 0.0 | $ 0.5 | $ 0.5 | $ 0.1 |

(1) These letters of credit renew annually and are shown on the basis that they will continue to renew beyond 2020.

(2) The amounts shown are the maximum theoretical amounts guaranteed under current agreements. Liabilities recognized represent the associated obligation under these agreements at June 30, 2016. The obligations under these letters of credit include certain accrued injuries and damages when a letter of credit covers the failure to pay these claims.

**Financial Covenants**

In order to utilize its bank credit facilities, TEC must meet certain financial tests, including a debt to capital ratio, as defined in the applicable agreements. In addition, TEC has certain restrictive covenants in specific agreements and debt instruments. At June 30, 2016, TEC was in compliance with all applicable financial covenants.

**9. Segment Information**

| *(millions)* *Three months ended June 30,* | Tampa Electric | PGS | Eliminations | Tampa Electric Company |
|---|---|---|---|---|
| **2016** | | | | |
| Revenues - external | $ 498.8 | $ 100.0 | $ 0.0 | $ 598.8 |
| Intracompany sales | 0.4 | 1.9 | (2.3) | 0.0 |
| Total revenues | 499.2 | 101.9 | (2.3) | 598.8 |
| Depreciation and amortization | 66.5 | 14.9 | 0.0 | 81.4 |
| Total interest charges | 22.6 | 3.7 | (0.1) | 26.2 |
| Provision for income taxes | 36.9 | 4.6 | 0.0 | 41.5 |
| Net income | $ 68.6 | $ 7.1 | $ 0.0 | 75.7 |
| **2015** | | | | |
| Revenues - external | $ 532.4 | $ 92.2 | $ 0.0 | $ 624.6 |
| Intracompany sales | 0.0 | 1.3 | (1.3) | 0.0 |
| Total revenues | 532.4 | 93.5 | (1.3) | 624.6 |
| Depreciation and amortization | 64.0 | 14.0 | 0.0 | 78.0 |
| Total interest charges | 23.6 | 3.6 | 0.0 | 27.2 |
| Provision for income taxes | 38.9 | 4.8 | 0.0 | 43.7 |
| Net income | $ 67.7 | $ 7.6 | $ 0.0 | $ 75.3 |
| *Six months ended June 30,* | | | | |
| **2016** | | | | |
| Revenues - external | $ 923.0 | $ 226.8 | $ 0.0 | $ 1,149.8 |
| Intracompany sales | 0.7 | 6.3 | (7.0) | 0.0 |
| Total revenues | 923.7 | 233.1 | (7.0) | 1,149.8 |
| Depreciation and amortization | 132.6 | 29.7 | 0.0 | 162.3 |
| Total interest charges | 46.4 | 7.4 | (0.1) | 53.7 |
| Provision for income taxes | 64.7 | 13.5 | 0.0 | 78.2 |
| Net income | $ 118.8 | $ 20.2 | $ 0.0 | $ 139.0 |
| **2015** | | | | |
| Revenues - external | $ 982.8 | $ 213.9 | $ 0.0 | $ 1,196.7 |
| Intracompany sales | 0.2 | 2.5 | (2.7) | 0.0 |
| Total revenues | 983.0 | 216.4 | (2.7) | 1,196.7 |
| Depreciation and amortization | 126.9 | 27.9 | 0.0 | 154.8 |
| Total interest charges | 47.1 | 7.1 | 0.0 | 54.2 |
| Provision for income taxes | 66.3 | 14.0 | 0.0 | 80.3 |
| Net income | $ 115.9 | $ 22.2 | $ 0.0 | $ 138.1 |
| **Total assets at June 30, 2016** | $ 6,720.1 | $ 1,099.8 | $ (3.2) | $ 7,816.7 |
| **Total assets at Dec. 31, 2015** (1) | 6,620.2 | 1,097.7 | (9.3) | 7,708.6 |

(1) Certain prior year amounts have been reclassified to conform to current year presentation.

**10. 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 11**). 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 June 30, 2016, all of TEC's physical contracts qualify for the NPNS exception.

The derivatives that are designated as cash flow hedges at June 30, 2016 and Dec. 31, 2015 are reflected on TEC's Consolidated Condensed Balance Sheets and classified accordingly as current and long-term assets and liabilities on a net basis as permitted by their respective master netting agreements. Derivative assets totaled $4.9 million and $0.0 as of June 30, 2016 and Dec. 31, 2015, respectively. Derivative liabilities totaled $0.7 million and $26.2 million as of June 30, 2016 and Dec. 31, 2015, respectively. There are minor offset amount differences between the gross derivative assets and liabilities and the net amounts presented on the Consolidated Condensed Balance Sheets. There was no cash collateral posted with or received from any counterparties.

All of the derivative assets and liabilities at June 30, 2016 and Dec. 31, 2015 are designated as hedging instruments, which primarily are derivative hedges of natural gas contracts to limit the exposure to changes in market price for natural gas used to produce energy and natural gas purchased for resale to customers. The corresponding effect of these natural gas related derivatives on the regulated utilities' fuel recovery clause mechanism is reflected on the Consolidated Condensed Balance Sheets as current and long-term regulatory assets and liabilities. Based on the fair value of the instruments at June 30, 2016, net pretax losses of $2.7 million are expected to be reclassified from regulatory assets or liabilities to the Consolidated Condensed Statements of Income within the next twelve months.

The June 30, 2016 and Dec. 31, 2015 balance in AOCI related to the cash flow hedges and interest rate swaps (unsettled and previously settled) is presented in **Note 12**.

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 three and six months ended June 30, 2016 and 2015, all hedges were effective. The derivative after-tax effect on OCI and the amount of after-tax gain or loss reclassified from AOCI into earnings for the three and six months ended June 30, 2016 and 2015 is presented in **Note 12**. Gains and losses were the result of interest rate contracts and the reclassification to income was reflected in "Interest expense".

The maximum length of time over which TEC is hedging its exposure to the variability in future cash flows extends to June 30, 2018 for financial natural gas contracts. The following table presents TEC's derivative volumes that, as of June 30, 2016, are expected to settle during the 2016, 2017 and 2018 fiscal years:

| *(millions)* | Natural Gas Contracts (MMBTUs) | |
|---|---|---|
| Year | Physical | Financial |
| 2016 | 0.0 | 17.0 |
| 2017 | 0.0 | 13.9 |
| 2018 | 0.0 | 2.6 |
| Total | 0.0 | 33.5 |

TEC is exposed to credit risk by 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 June 30, 2016, 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 generally do not require a nonperformance risk adjustment 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.

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 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.

## 11. Fair Value Measurements

### Items Measured at Fair Value on a Recurring Basis

Accounting guidance governing fair value measurements and disclosures provides that fair value represents the amount that would be received in selling an asset or the amount that would be paid in transferring a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that is determined based upon assumptions that market participants would use in pricing an asset or liability. As a basis for considering such assumptions, accounting guidance also establishes a three-tier fair value hierarchy, which prioritizes the inputs used in measuring fair value as follows:

Level 1: Observable inputs, such as quoted prices in active markets;

Level 2: Inputs, other than quoted prices in active markets, that are observable either directly or indirectly; and

Level 3: Unobservable inputs for which there is little or no market data, which require the reporting entity to develop its own assumptions.

Assets and liabilities are measured at fair value based on one or more of the following three valuation techniques noted under accounting guidance:

*(A)* Market approach: Prices and other relevant information generated by market transactions involving identical or comparable assets or liabilities;

*(B)* Cost approach*:* Amount that would be required to replace the service capacity of an asset (replacement cost); and

*(C)* Income approach*:* Techniques to convert future amounts to a single present amount based upon market expectations (including present value techniques, option-pricing and excess earnings models).

The fair value of financial instruments is determined by using various market data and other valuation techniques.

The following tables set 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 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.

**Recurring Derivative Fair Value Measures**

| | *As of June 30, 2016* | | | |
|---|---|---|---|---|
| *(millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Assets** | | | | |
| Natural gas swaps | $ 0.0 | $ 4.9 | $ 0.0 | $ 4.9 |
| **Liabilities** | | | | |
| Natural gas swaps | $ 0.0 | $ 0.7 | $ 0.0 | $ 0.7 |

| | *As of Dec. 31, 2015* | | | |
|---|---|---|---|---|
| *(millions)* | Level 1 | Level 2 | Level 3 | Total |
| **Liabilities** | | | | |
| Natural gas swaps | $ 0.0 | $ 26.2 | $ 0.0 | $ 26.2 |

Natural gas swaps are OTC swap instruments. The fair value of the swaps is estimated utilizing the market approach. The price of swaps is calculated using observable NYMEX quoted closing prices of exchange-traded futures. These prices are applied to the notional quantities of active positions to determine the reported fair value (see **Note 10**).

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 June 30, 2016, the fair value of derivatives was not materially affected by nonperformance risk. There were no Level 3 assets or liabilities for the periods presented.

### 12. Other Comprehensive Income

| **Other Comprehensive Income** | *Three months ended June 30,* | | | *Six months ended June 30,* | | |
|---|---|---|---|---|---|---|
| *(millions)* | Gross | Tax | Net | Gross | Tax | Net |
| **2016** | | | | | | |
| Unrealized gain on cash flow hedges | $ 0.0 | $ 0.0 | $ 0.0 | $ 0.0 | $ 0.0 | $ 0.0 |
| Reclassification from AOCI to net income | 0.3 | (0.1) | 0.2 | 0.7 | (0.3) | 0.4 |
| Gain on cash flow hedges | 0.3 | (0.1) | 0.2 | 0.7 | (0.3) | 0.4 |
| Total other comprehensive income | $ 0.3 | $ (0.1) | $ 0.2 | $ 0.7 | $ (0.3) | $ 0.4 |
| **2015** | | | | | | |
| Unrealized gain on cash flow hedges | $ 4.0 | $ (1.4) | $ 2.6 | $ 4.3 | $ (1.5) | $ 2.8 |
| Reclassification from AOCI to net income | 0.3 | (0.1) | 0.2 | 0.7 | (0.4) | 0.3 |
| Gain on cash flow hedges | 4.3 | (1.5) | 2.8 | 5.0 | (1.9) | 3.1 |
| Total other comprehensive income | $ 4.3 | $ (1.5) | $ 2.8 | $ 5.0 | $ (1.9) | $ 3.1 |

| **Accumulated Other Comprehensive Loss** | | |
|---|---|---|
| *(millions)* | *June 30, 2016* | *Dec. 31, 2015* |
| Net unrealized losses from cash flow hedges (1) | $ (3.2) | $ (3.6) |
| Total accumulated other comprehensive loss | $ (3.2) | $ (3.6) |

(1) Net of tax benefit of $2.0 million and $2.3 million as of June 30, 2016 and Dec. 31, 2015, respectively.

**13. 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.

Tampa Electric 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 250 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 variable interests. These risks include: operating and maintenance, regulatory, credit, commodity/fuel and energy market risk. Tampa Electric 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, and have the obligation or right to absorb losses or benefits. As a result, Tampa Electric is not the primary beneficiary and is not required to consolidate any of these entities. Tampa Electric purchased $16.4 million and $29.0 million under these PPAs for the three and six months ended June 30, 2016, respectively, and $9.9 million and $15.3 million for the three and six months ended June 30, 2015, respectively.

TEC does not provide any material financial or other support to any of the VIEs it is involved with, nor is TEC under any obligation to absorb losses associated with these VIEs. In the normal course of business, TEC's involvement with these VIEs does not affect its Consolidated Condensed Balance Sheets, Statements of Income or Cash Flows.

**14. Mergers and Acquisitions**

**Merger with Emera Inc.**

As disclosed in **Note 1,** TEC is a wholly owned subsidiary of TECO Energy. On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on Sept. 4, 2015. As a result of the Merger, Merger Sub merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera. Therefore, TEC continues to be a wholly owned subsidiary of TECO Energy and became an indirect wholly owned subsidiary of Emera as of July 1, 2016.

Pursuant to the Merger Agreement, upon the closing of the Merger, each issued and outstanding share of TECO Energy common stock was cancelled and converted automatically into the right to receive $27.55 in cash, without interest (Merger Consideration). This represents an aggregate purchase price of approximately $10.7 billion including Emera's purchase price allocation for debt of approximately $4.2 billion (of which TEC's portion of debt was $2.3 billion).

The Merger Agreement requires Emera, among other things, (i) to maintain TECO Energy's historic levels of community involvement and charitable contributions and support in TECO Energy's existing service territories, (ii) to maintain TECO Energy's and TEC's headquarters in Tampa, Florida, (iii) to honor current union contracts in accordance with their terms and (iv) to provide each continuing non-union employee, for a period of two years following the closing of the Merger, with a base salary or wage rate no less favorable than, and incentive compensation and employee benefits, respectively, substantially comparable in the aggregate to those that they received as of immediately prior to the closing.

**15. Subsequent Events**

On July 1, 2016, TECO Energy and Emera completed the Merger contemplated by the Merger Agreement entered into on Sept. 4, 2015. As a result of the Merger, Merger Sub merged with and into TECO Energy with TECO Energy continuing as the surviving corporation and becoming a wholly owned indirect subsidiary of Emera. As TEC is a wholly owned subsidiary of TECO Energy, TEC became an indirect wholly owned subsidiary of Emera. See **Note 14** for further information.

## Item 2. MANAGEMENT'S DISCUSSION & ANALYSIS OF FINANCIAL CONDITION & 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. The forecasted results are based on the company's current expectations and assumptions, and the company does not undertake to update that information or any other information contained in this Managements Discussion & Analysis, except as may be required by law. Factors that could impact actual results include: the ability to retain and motivate the workforce during the period of integration with Emera; regulatory actions by federal, state or local authorities; unexpected capital needs or unanticipated reductions in cash flow that affect liquidity; the ability to access the capital and credit markets when required; general economic conditions affecting customer growth and energy sales at the utility companies; economic conditions affecting the Florida and New Mexico economies; weather variations and customer energy usage patterns affecting sales and operating costs at the utilities and the effect of weather conditions on energy consumption; the effect of extreme weather conditions or hurricanes; general operating conditions; input commodity prices affecting cost at all of the operating companies; natural gas demand at the utilities; and the ability of TECO Energy's subsidiaries to operate equipment without undue accidents, breakdowns or failures. Additional information is contained under "Risk Factors" in Item 1A Risk Factors of Part II of this Quarterly Report.*

### Acquisition by Emera

On July 1, 2016, the acquisition of TECO Energy by Emera closed. Upon closing, TECO Energy became a wholly owned indirect subsidiary of Emera. Pursuant to the Merger Agreement, upon closing, each issued and outstanding share of TECO Energy common stock was cancelled and converted into the right to receive $27.55 in cash, without interest (see **Note 16** to the **TECO Energy Consolidated Financial Statements**).

**Earnings Summary -** Unaudited

| *(millions) Except per-share amounts* | *Three Months Ended June 30, 2016* | *Three Months Ended June 30, 2015* | *Six Months Ended June 30, 2016* | *Six Months Ended June 30, 2015* |
|---|---|---|---|---|
| Consolidated revenues | $ 652.3 | $ 680.6 | $ 1,311.8 | $ 1,373.6 |
| Net income from continuing operations | 5.5 | 61.5 | 79.2 | 125.3 |
| Loss on discontinued operations, net | (0.2) | (49.7) | (0.1) | (55.5) |
| Net income | 5.3 | 11.8 | 79.1 | 69.8 |
| **Average common shares outstanding** | | | | |
| Basic | 234.3 | 233.0 | 234.1 | 232.9 |
| Diluted | 235.5 | 233.6 | 235.4 | 233.5 |
| **Earnings per share – basic** | | | | |
| Continuing operations | $ 0.03 | $ 0.26 | $ 0.34 | $ 0.53 |
| Discontinued operations | 0.00 | (0.21) | 0.00 | (0.23) |
| Earnings per share - basic | $ 0.03 | $ 0.05 | $ 0.34 | $ 0.30 |
| **Earnings per share – diluted** | | | | |
| Continuing operations | $ 0.03 | $ 0.26 | $ 0.34 | $ 0.53 |
| Discontinued operations | 0.00 | (0.21) | 0.00 | (0.23) |
| Earnings per share - diluted | $ 0.03 | $ 0.05 | $ 0.34 | $ 0.30 |

### Operating Results

#### Three Months Ended June 30, 2016

Second-quarter 2016 net income was $5.3 million, or $0.03 per share, compared with $11.8 million, or $0.05 per share, in the second quarter of 2015. Net income from continuing operations was $5.5 million, or $0.03 per share, in the 2016 second quarter, compared with $61.5 million, or $0.26 per share, for the same period in 2015. Net income from continuing operations in the 2016 period reflects $58.4 million of Emera acquisition-related costs ($71.4 million pretax) (see **Note 16** to the **TECO Energy Consolidated Financial Statements**). The second quarter losses in discontinued operations of $49.7 million in 2015 reflected the operating results and charges associated with TECO Coal, which was sold in 2015 (see **Note 15** to the **TECO Energy Consolidated Financial Statements**).

#### Six Months Ended June 30, 2016

Year-to-date net income through the second quarter of 2016 was $79.1 million, or $0.34 per share, compared with $69.8 million, or $0.30 per share, in the 2015 year-to-date period. Net income from continuing operations was $79.2 million, or $0.34 per share, in the 2016 year-to-date period, compared with $125.3 million, or $0.53 per share, for the same period in 2015. Year-to-date 2016 net income reflects $58.5 million of Emera acquisition-related costs. The $55.5 million year-to-date loss in discontinued operations in 2015 reflected the operating results and charges associated with TECO Coal, which was sold in 2015.

**Operating Company Results**

All amounts included in the operating company discussions below are after tax, unless otherwise noted.

**Tampa Electric Company – Electric Division**

Tampa Electric's net income for the second quarter of 2016 was $68.6 million, compared with $67.7 million for the same period in 2015. Second-quarter net income in 2016 included $6.0 million of AFUDC-equity, which represents allowed equity cost capitalized to construction costs, compared with $3.7 million in the 2015 quarter. Results for the quarter reflected a 1.6% higher average number of customers. Energy sales were lower due to more normal weather compared to the second quarter of 2015 when consistently higher than normal spring temperatures were experienced. Results reflected operations and maintenance expense slightly higher than in 2015 and higher depreciation expenses.

Total degree days in Tampa Electric's service area in the second quarter of 2016 were 5% above normal, but 10% below the 2015 period, when degree days were 15% above normal. Total net energy for load decreased 2.6% in the second quarter of 2016, compared with the same period in 2015. In the 2016 period, pretax base revenues were $2.5 million lower than in 2015, as lower energy sales from more normal weather was only partially offset by customer growth and $1.6 million of higher pretax base revenue from higher base rates effective Nov. 1, 2015, as a result of the 2013 rate case settlement.

While net energy for load is a calendar measurement of retail energy sales rather than a billing-cycle measurement, the quarterly energy sales shown on the following table reflect the energy sales based on billing cycles, which can vary period to period. Retail energy sales to residential and commercial customers decreased in the second quarter of 2016 primarily due to milder weather compared to the 2015 quarter when spring temperatures were higher. Sales to non-phosphate industrial customers increased due to the strength of the Tampa area economy. Sales to lower-margin industrial-phosphate customers decreased as self-generation by those customers increased and mining activity migrates out of Tampa Electric's service area.

In the second quarter of 2016 operations and maintenance expense, excluding all FPSC-approved cost-recovery clauses, was slightly higher than in the 2015 quarter, reflecting higher costs to safely and reliably operate and maintain the generating system and provide high-quality customer service, essentially offset by lower employee-related costs primarily due to the lower level of short-term incentive accruals for all employees in 2016 compared to 2015. Depreciation and amortization expense increased $1.5 million in 2016 as a result of normal additions to facilities to reliably serve customers.

Tampa Electric's year-to-date net income through the second quarter of 2016 was $118.8 million, compared with $115.9 million for the same period in 2015. Year-to-date net income in 2016 included $11.6 million of AFUDC-equity, which represents allowed equity cost capitalized to construction costs, compared with $7.5 million in the 2015 period. Results for the year-to-date period reflected a 1.6% higher average number of customers. Energy sales were lower compared to 2015 due to the well-above-normal second quarter temperatures experienced in the 2015 period. Results reflected operations and maintenance expense slightly higher than in 2015 and higher depreciation expense.

Total degree days in Tampa Electric's service area for the year-to-date period of 2016 were 5% above normal, but 9% below the 2015 period. Total net energy for load decreased 0.9% in the year-to-date 2016 period, compared with the same period in 2015. In the 2016 year-to-date period, pretax base revenues were $3.8 million higher than in 2015, as lower energy sales to residential customers from more normal weather was more than offset by customer growth, higher sales to industrial customers, and $2.7 million of higher pretax base revenue from higher base rates effective Nov. 1, 2015 as a result of the 2013 rate case settlement.

In the 2016 year-to-date period, retail energy sales to residential customers decreased primarily from milder spring weather than was experienced in the 2015 period. Sales to non-phosphate industrial customers increased due to the strength of the Tampa area economy. Sales to lower-margin industrial-phosphate customers decreased as a result of the same factors as the second quarter.

In the 2016 year-to-date period, operations and maintenance expense, excluding all FPSC-approved cost-recovery clauses, was almost $1.0 million higher than in the 2015 period, reflecting higher costs to safely and reliably operate and maintain the generating, transmission and distribution systems and provide high-quality customer service, partially offset by lower employee-related costs, primarily due to the lower level of short-term incentive accruals for all employees in 2016 compared to 2015. Depreciation and amortization expense increased $3.5 million in 2016, as a result of normal additions to facilities to reliably serve customers.

A summary of Tampa Electric's regulated operating statistics for the three and six months ended June 30, 2016 and 2015 follows:

| *(millions, except average customers and total degree days)* | *Operating Revenues* | | | *Kilowatt-hour sales* | | |
|---|---|---|---|---|---|---|
| ***Three months ended June 30,*** | *2016* | *2015* | *% Change* | *2016* | *2015* | *% Change* |
| **By Customer Type** | | | | | | |
| Residential | $ 252.6 | $ 267.4 | (5.5) | 2,240.7 | 2,330.6 | (3.9) |
| Commercial | 147.6 | 154.9 | (4.7) | 1,565.2 | 1,609.9 | (2.8) |
| Industrial – Phosphate | 12.7 | 13.8 | (8.0) | 158.1 | 173.2 | (8.7) |
| Industrial – Other | 27.4 | 27.9 | (1.8) | 320.7 | 319.5 | 0.4 |
| Other sales of electricity | 43.3 | 44.9 | (3.6) | 446.7 | 456.0 | (2.0) |
| Deferred and other revenues (1) | 1.9 | 9.3 | (79.6) | | | |
| Total energy sales | $ 485.5 | $ 518.2 | (6.3) | 4,731.4 | 4,889.2 | (3.2) |
| Sales for resale | 0.7 | 1.0 | (30.0) | 18.3 | 31.2 | (41.3) |
| Other operating revenue | 13.0 | 13.3 | (2.3) | | | |
| Total revenues | $ 499.2 | $ 532.5 | (6.3) | 4,749.7 | 4,920.4 | (3.5) |
| Average customers (thousands) | 729.3 | 717.9 | 1.6 | | | |
| Retail net energy for load (kilowatt hours) | | | | 5,261.5 | 5,401.2 | (2.6) |
| Total degree days | | | | 1,255 | 1,404 | (10.6) |
| ***Six months ended June 30,*** | | | | | | |
| **By Customer Type** | | | | | | |
| Residential | $ 470.0 | $ 480.8 | (2.2) | 4,155.3 | 4,170.0 | (0.4) |
| Commercial | 280.4 | 287.9 | (2.6) | 2,953.2 | 2,960.1 | (0.2) |
| Industrial – Phosphate | 25.8 | 27.3 | (5.5) | 321.6 | 340.9 | (5.7) |
| Industrial – Other | 52.9 | 52.7 | 0.4 | 617.9 | 598.9 | 3.2 |
| Other sales of electricity | 82.8 | 85.4 | (3.0) | 848.0 | 856.1 | (0.9) |
| Deferred and other revenues (1) | (17.5) | 16.7 | (204.8) | | | |
| Total energy sales | 894.4 | 950.8 | (5.9) | 8,896.0 | 8,926.0 | (0.3) |
| Sales for resale | 2.1 | 2.9 | (27.6) | 68.6 | 84.7 | (19.0) |
| Other operating revenue | 27.2 | 29.4 | (7.5) | | | |
| Total revenues | $ 923.7 | $ 983.1 | (6.0) | 8,964.6 | 9,010.7 | (0.5) |
| Average customers (thousands) | 727.7 | 716.0 | 1.6 | | | |
| Retail net energy for load (kilowatt hours) | | | | 9,578.5 | 9,664.9 | (0.9) |
| Total degree days | | | | 1,857 | 2,034 | (8.7) |

(1) Primarily reflects the timing of environmental and fuel clause recoveries.

**Tampa Electric Company – Natural Gas Division**

PGS reported net income of $7.1 million for the second quarter, compared with $7.6 million in the 2015 quarter. Average customer growth was 2.3% in the quarter. Therm sales to residential and commercial customers increased primarily as a result of customer growth. Sales to commercial and industrial customers increased as a result of the stronger Florida economy and increased sales of compressed natural gas to vehicle fleets. Off-system sales increased, reflecting higher levels of operation by gas-fired generation in Florida due to lower natural gas prices and weather-related demand. Second-quarter results in 2016 reflected non-fuel operations and maintenance expense $1.1 million higher than in 2015, driven by higher operating and compliance costs due to increasing pipeline safety regulations, partially offset by lower employee-related costs primarily due to the lower level of short-term incentive accruals for all employees in 2016 compared to 2015. Depreciation and amortization increased slightly due to normal additions to facilities to serve customers.

PGS reported net income of $20.2 million for the 2016 year-to-date period, compared with $22.2 million in the 2015 period. These results reflect higher therm sales as a result of the same factors that drove therm sales in the second quarter. Operations and maintenance expense was $2.1 million higher and depreciation expense was $1.0 million higher than the 2015 period, both driven by the same factors as the second quarter.

A summary of PGS's regulated operating statistics for the three and six months ended June 30, 2016 and 2015 follows:

| *(millions, except average customers)* | *Operating Revenues* | | | *Therms* | | |
|---|---|---|---|---|---|---|
| ***Three months ended June 30,*** | *2016* | *2015* | *% Change* | *2016* | *2015* | *% Change* |
| **By Customer Type** | | | | | | |
| Residential | $ 30.5 | $ 28.1 | 8.5 | 14.6 | 12.5 | 16.8 |
| Commercial | 34.5 | 32.5 | 6.2 | 117.8 | 109.9 | 7.2 |
| Industrial | 3.4 | 3.2 | 6.2 | 77.9 | 70.2 | 11.0 |
| Off system sales | 18.4 | 14.4 | 27.8 | 72.2 | 46.4 | 55.6 |
| Power generation | 0.1 | 1.9 | (94.7) | 189.1 | 190.8 | (0.9) |
| Other revenues | 12.3 | 11.1 | 10.8 | | | |
| Total | $ 99.2 | $ 91.2 | 8.8 | 471.6 | 429.8 | 9.7 |
| **By Sales Type** | | | | | | |
| System supply | $ 57.5 | $ 51.6 | 11.4 | 92.5 | 65.7 | 40.8 |
| Transportation | 29.3 | 28.5 | 2.8 | 379.1 | 364.1 | 4.1 |
| Other revenues | 12.4 | 11.1 | 11.7 | | | |
| Total | $ 99.2 | $ 91.2 | 8.8 | 471.6 | 429.8 | 9.7 |
| Average customers (thousands) | 369.9 | 361.7 | 2.3 | | | |
| ***Six months ended June 30,*** | | | | | | |
| **By Customer Type** | | | | | | |
| Residential | $ 81.0 | $ 77.3 | 4.8 | 47.5 | 46.9 | 1.3 |
| Commercial | 77.3 | 74.1 | 4.3 | 258.9 | 248.1 | 4.4 |
| Industrial | 6.7 | 6.4 | 4.7 | 161.4 | 146.3 | 10.3 |
| Off system sales | 31.3 | 22.2 | 41.0 | 126.0 | 69.8 | 80.5 |
| Power generation | 2.1 | 3.9 | (46.2) | 379.7 | 375.4 | 1.1 |
| Other revenues | 28.9 | 27.3 | 5.9 | | | |
| Total | $ 227.3 | $ 211.2 | 7.6 | 973.5 | 886.5 | 9.8 |
| **By Sales Type** | | | | | | |
| System supply | $ 132.9 | $ 121.0 | 9.8 | 186.6 | 132.0 | 41.4 |
| Transportation | 65.5 | 62.9 | 4.1 | 786.9 | 754.5 | 4.3 |
| Other revenues | 28.9 | 27.3 | 5.9 | | | |
| Total | $ 227.3 | $ 211.2 | 7.6 | 973.5 | 886.5 | 9.8 |
| Average customers (thousands) | 368.7 | 360.4 | 2.3 | | | |

**New Mexico Gas Company**

NMGC reported a second-quarter loss of $0.2 million, compared with a $0.1 million loss in the 2015 period. Growth in the average number of customers in the 2016 quarter and year-to-date periods were 0.6%. In the second quarter, heating degree days were 7% above normal but 3% below the 2015 quarter. Non-fuel operating and maintenance expense was slightly higher than in the 2015 quarter due to higher employee related expenses. Results included $0.6 million of pretax rate credits to customers under the stipulation approved by the NMPRC in 2014.

NMGC reported year-to-date net income of $15.0 million compared with $13.8 million in the 2015 period. Results reflected the benefit of heating degree days that were slightly higher than in 2015, but more than 4% below normal. Operating and maintenance expense was essentially unchanged from the prior period. Results included $2.5 million of pretax rate credits to customers under the stipulation approved by the NMPRC in 2014.

NMGC expects to record $30.4 million of pretax expense in the third quarter of 2016 related to the conditions contained in the Emera acquisition stipulation approved by the NMPRC (see **Note 16** to the **TECO Energy Consolidated Financial Statements**).

A summary of NMGC's regulated operating statistics for the three and six months ended June 30, 2016 and 2015 follows:

| *(millions, except average customers and total degree days)* | *Operating Revenues* | | | *Therms* | | |
|---|---|---|---|---|---|---|
| ***Three months ended June 30,*** | *2016* | *2015* | *% Change* | *2016* | *2015* | *% Change* |
| **By Customer Type** | | | | | | |
| Residential | $ 37.1 | $ 38.2 | (2.9) | 42.8 | 38.9 | 10.0 |
| Commercial | 8.5 | 10.1 | (15.8) | 16.1 | 16.8 | (4.2) |
| Industrial | 0.1 | 0.1 | - | 0.2 | 0.2 | - |
| Off system sales | 0.2 | 0.2 | - | 0.0 | 0.0 | - |
| On system transportation | 4.1 | 3.7 | 10.8 | 76.1 | 73.4 | 3.7 |
| Off system transportation | 0.2 | 0.2 | - | 12.3 | 12.3 | - |
| Other revenues | 1.5 | 1.5 | - | | | |
| Total | $ 51.7 | $ 54.0 | (4.3) | 147.5 | 141.6 | 4.2 |
| **By Sales Type** | | | | | | |
| System supply | $ 45.9 | $ 48.6 | (5.6) | 59.1 | 55.9 | 5.7 |
| Transportation | 4.3 | 3.9 | 10.3 | 88.4 | 85.7 | 3.2 |
| Other revenues | 1.5 | 1.5 | - | | | |
| Total | $ 51.7 | $ 54.0 | (4.3) | 147.5 | 141.6 | 4.2 |
| Average customers (thousands) | 518.8 | 515.8 | 0.6 | | | |
| Total degree days | | | | 457 | 472 | (3.2) |
| | | | | | | |
| ***Six months ended June 30,*** | | | | | | |
| **By Customer Type** | | | | | | |
| Residential | $ 114.8 | $ 125.7 | (8.7) | 165.3 | 160.1 | 3.2 |
| Commercial | 28.1 | 33.1 | (15.1) | 58.1 | 57.8 | 0.5 |
| Industrial | 0.3 | 0.3 | - | 0.7 | 0.7 | - |
| Off system sales | 1.0 | 0.7 | 42.9 | 3.9 | 1.2 | 225.0 |
| On system transportation | 10.7 | 9.8 | 9.2 | 171.2 | 158.1 | 8.3 |
| Off system transportation | 0.4 | 0.4 | - | 23.4 | 22.6 | 3.5 |
| Other revenues | 3.0 | 3.0 | - | | | |
| Total | $ 158.3 | $ 173.0 | (8.5) | 422.6 | 400.5 | 5.5 |
| **By Sales Type** | | | | | | |
| System supply | $ 144.2 | $ 159.8 | (9.8) | 228.0 | 219.8 | 3.7 |
| Transportation | 11.1 | 10.2 | 8.8 | 194.6 | 180.7 | 7.7 |
| Other revenues | 3.0 | 3.0 | - | | | |
| Total | $ 158.3 | $ 173.0 | (8.5) | 422.6 | 400.5 | 5.5 |
| Average customers (thousands) | 519.3 | 516.3 | 0.6 | | | |
| Total degree days | | | | 2,427 | 2,393 | 1.4 |

**Other (net)**

The second quarter 2016 cost for Other – net was $70.2 million, which included $0.2 million in discontinued operations related to TECO Coal, which was sold in 2015. The second quarter 2016 cost from continuing operations for Other – net was $70.0 million and included $58.4 million ($71.4 million pretax) of costs associated with the Emera transaction, compared with the cost of $13.7 million in 2015, which included $0.4 million of NMGC-related integration costs. Emera transaction costs included primarily employee-related and consultant fees (see **Note 16** to the **TECO Energy Consolidated Financial Statements**). Year-to-date 2016 cost for Other – net was $74.9 million, compared with $24.6 million in the 2015 period, which included $1.0 million of NMGC integration costs. Year-to-date cost from continuing operations for Other – net was $74.8 million compared with $26.6 million in the 2015 period. Year-to-date 2016 costs reflect the Emera transaction costs, a $5.8 million tax benefit due to an accounting rule change related to stock-based incentive compensation recorded in the first quarter, and lower interest expense as a result of refinancing debt maturities.

The segment data in **Note 11** to the **TECO Energy Consolidated Condensed Financial Statements** presents Other and Eliminations as separate segments. The discussion above nets the two segments.

**Discontinued Operations – TECO Coal**

The sale of TECO Coal closed in September 2015. The $0.2 million second quarter 2016 loss recorded in discontinued operations reflects trailing costs associated with the sale of TECO Coal recorded in the Other – net segment, compared with a $49.7 million loss in the 2015 period, which reflected TECO Coal's operating results prior to its sale, net of impairment charges. The $0.1 million loss in discontinued operations for the 2016 year-to-date period reflects the second quarter cost net of a $0.1 million refund of prepaid costs recorded in the first quarter of 2016, compared with a loss of $55.5 million in the 2015 period, which reflected TECO Coal's operating results prior to its sale net of impairment charges (see **Note 15** to the **TECO Energy Consolidated Financial Statements**).

**Income Taxes**

The provisions for income taxes from continuing operations for the six month periods ended June 30, 2016 and 2015 were $60.0 million and $80.4 million, respectively. The provision for income taxes for the six months ended June 30, 2016 was impacted by lower pre-tax income and a tax benefit related to long-term incentive compensation offset by the tax impact of the Merger transaction costs. (see **Note 2** and **Note 16** to the **TECO Energy Consolidated Financial Statements**).

**Liquidity and Capital Resources**

The table below sets forth the June 30, 2016 consolidated liquidity and cash balances, the cash balances at the operating companies and Parent, and amounts available under the TECO Energy/TECO Finance, TEC and NMGC credit facilities.

| *(millions)* | Consolidated | TEC | NMGC | TECO Finance Parent/other |
|---|---|---|---|---|
| Credit facilities (1) | $ 1,300.0 | $ 475.0 | $ 125.0 | $ 700.0 |
| Drawn amounts/letters of credit (1) | 617.2 | 123.5 | 3.7 | 490.0 |
| Available credit facilities | 682.8 | 351.5 | 121.3 | 210.0 |
| Cash and short-term investments | 29.2 | 13.8 | 1.7 | 13.7 |
| Total liquidity | $ 712.0 | $ 365.3 | $ 123.0 | $ 223.7 |

(1) Includes amounts under the TECO Energy/TECO Finance $400 million one-year term loan facility that was fully funded on June 30, 2016.

**Cash Impacts of the Emera Acquisition**

We expect net cash outflows associated with the acquisition of approximately $50 million in 2016, primarily in the third quarter, and approximately $20 million in 2017 (representing cash payments of transaction costs accrued at June 30). In connection with the stipulation approved by the NMPRC, pre-tax costs of approximately $30 million are expected to be recorded in the third quarter of 2016, with associated cash outflows over a 5-year period. In addition, a $27 million pro-rated dividend was paid to TECO Energy shareholders in July 2016.

**Covenants in Financing Agreements**

In order to utilize their respective bank credit facilities, TECO Energy and its subsidiaries must meet certain financial tests as defined in the applicable agreements. In addition, TECO Energy and its subsidiaries have certain restrictive covenants in specific agreements and debt instruments. At June 30, 2016, TECO Energy and its subsidiaries were in compliance with all required financial covenants. The table that follows lists the significant financial covenants and the performance relative to them at June 30, 2016. Reference is made to the specific agreements and instruments for more details.

**Significant Financial Covenants**
*(millions, unless otherwise indicated)*

| Instrument | Financial Covenant (1) | Requirement/Restriction | Calculation June 30, 2016 |
|---|---|---|---|
| **TEC** | | | |
| Credit facility (2) | Debt/capital | Cannot exceed 65% | 46.2% |
| Accounts receivable credit facility (2) | Debt/capital | Cannot exceed 65% | 46.2% |
| **NMGC** | | | |
| Credit facility (2) | Debt/capital | Cannot exceed 65% | 29.1% |
| 3.54% and 4.87% senior unsecured notes | Debt/capital | Cannot exceed 65% | 29.1% |
| **NMGI** | | | |
| 2.71% and 3.64% senior unsecured notes | Debt/capital | Cannot exceed 65% | 46.1% |
| **TECO Energy/TECO Finance** | | | |
| Credit facility - 2013 $300 million (2) | Debt/capital | Cannot exceed 65% | 62.4% |
| Credit facility - 2016 $400 million (2) | Debt/capital | Cannot exceed 65% | 62.4% |

(1) As defined in each applicable instrument.
(2) See **Note 6** to the **TECO Energy Consolidated Condensed Financial Statements** for a description of the credit facilities.

**Credit Ratings of Senior Unsecured Debt at June 30, 2016**

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

On July 6, 2016, Moody's downgraded the credit ratings of TECO Energy/TECO Finance to Baa2 from Baa1 and the issuer rating and senior unsecured ratings of Tampa Electric Company to A3 from A2. This concluded the ratings review commenced by Moody's on June 2, 2016. Moody's described the ratings outlook for the companies as stable.

On July 1, 2016, following the Merger with Emera, S&P affirmed the issuer credit ratings of TECO Energy and the senior unsecured debt ratings of its subsidiaries, TECO Finance, Tampa Electric Company and NMGC, and maintained the ratings outlook at negative.

On Sept. 8, 2015, Fitch Ratings affirmed the issuer default ratings of TECO Energy and the senior unsecured debt rating of its subsidiaries, TECO Finance and TEC, following the announcement of the pending Merger with Emera. On Oct. 9, 2015, Fitch Ratings affirmed the issuer default ratings of TECO Energy at BBB and TEC at BBB+ and affirmed the senior unsecured debt rating of its subsidiaries, TECO Finance and TEC. Fitch Ratings also described the ratings outlook as "Stable".

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, the credit rating agencies assign TECO Energy, TECO Finance, TEC and NMGC'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** in Item 1A of **Part II** of this quarterly report). 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.

**Fair Value Measurements**

All 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 accounting standards for regulated operations, the changes in value of natural gas derivatives of Tampa Electric, PGS and NMGC 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.

The valuation methods used to determine fair value are described in **Notes 7 and 13** to the **TECO Energy Consolidated Condensed Financial Statements**. In addition, 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 and the intent of the parties, indications of credit deterioration and whether the markets in which the company transacts have experienced dislocation. At June 30, 2016, the fair value of derivatives was not materially affected by nonperformance risk.

**Critical Accounting Policies and Estimates**

The company's critical accounting policies relate to deferred income taxes, employee postretirement benefits, long-lived assets, goodwill and regulatory accounting. For further discussion of critical accounting policies, see **TECO Energy's Annual Report on Form 10-K** for the year ended Dec. 31, 2015.

## Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### Changes in Fair Value of Derivatives

The change in fair value of derivatives is largely due to settlements of natural gas swaps and the increase in the average market price component of the company's outstanding natural gas swaps of approximately 13% from Dec. 31, 2015 to June 30, 2016. For natural gas, the company maintained a similar volume hedged as of June 30, 2016 as compared to Dec. 31, 2015.

The following tables summarize the changes in and the fair value balances of derivative assets (liabilities) for the six month period ended June 30, 2016:

| **Change in Fair Value of Derivatives *(millions)*** | | |
|---|---|---|
| Net fair value of derivatives as of Dec. 31, 2015 | $ | (26.0) |
| Additions and net changes in unrealized fair value of derivatives | | 6.6 |
| Changes in valuation techniques and assumptions | | 0.0 |
| Realized net settlement of derivatives | | 23.8 |
| Net fair value of derivatives as of June 30, 2016 | $ | 4.4 |

| **Roll-Forward of Derivative Net Assets (Liabilities) *(millions)*** | | |
|---|---|---|
| Total derivative net assets (liabilities) as of Dec. 31, 2015 | $ | (26.0) |
| Change in fair value of derivative net assets (liabilities): | | |
| Recorded as regulatory assets and liabilities or other comprehensive income | | 6.2 |
| Recorded in earnings | | 0.0 |
| Realized net settlement of derivatives | | 23.8 |
| Option premium payments | | 0.4 |
| Net fair value of derivatives as of June 30, 2016 | $ | 4.4 |

Below is a summary table of sources of fair value, by maturity period, for derivative contracts at June 30, 2016:

| **Maturity and Source of Derivative Contracts Net Assets (Liabilities) *(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) | 3.0 | 1.4 | 4.4 |
| Model prices (2) | 0.0 | 0.0 | 0.0 |
| Total | $ 3.0 | $ 1.4 | $ 4.4 |

(1) Reflects over-the-counter natural gas derivative contracts 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.

## Item 4. CONTROLS AND PROCEDURES

### TECO Energy, Inc.

**(a) Evaluation 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 (the Exchange Act)) as of the end of the period covered by this quarterly report (the Evaluation Date). Based on such evaluation, TECO Energy's principal financial officer and principal executive officer have concluded that, as of the Evaluation Date, TECO Energy's disclosure controls and procedures are effective.

**(b) Changes in Internal Controls**. 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 control over financial reporting 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

**(a) Evaluation 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 Exchange Act) as of the end of the Evaluation Date. Based on such evaluation, TEC's principal financial officer and principal executive officer have concluded that, as of the Evaluation Date, TEC's disclosure controls and procedures are effective.

**(b) Changes in Internal Controls**. There was no change in TEC'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 TEC's internal control over financial reporting that occurred during TEC's last fiscal quarter that has materially affected, or is reasonably likely to materially affect, such controls.

## PART II. OTHER INFORMATION

### Item 1. LEGAL PROCEEDINGS

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

For a discussion of certain legal proceedings and environmental matters, including an update of previously disclosed legal proceedings and environmental matters, see **Notes 10** and **8**, **Commitments and Contingencies**, of the **TECO Energy** and **Tampa Electric Company Consolidated Financial Statements**, respectively.

### Item 1A. RISK FACTORS

TECO Energy updated the risk factors in its 2015 Annual Report on Form 10-K as described below.

**Risks Associated with the Integration with Emera**

**TECO Energy and its subsidiaries are subject to business uncertainties during the period of integration with Emera that could adversely affect TECO Energy's financial results.**

Uncertainty about the effect of the Merger on employees or vendors and others, including contractors, may have an adverse effect on TECO Energy. These uncertainties may impair TECO Energy's and its subsidiaries' ability to attract, retain and motivate key personnel, and could cause vendors and others, including contractors, that deal with TECO Energy to seek to change existing business relationships. Employee retention and recruitment may continue to be challenging after the completion of the Merger, as current employees and prospective employees may experience uncertainty about their future roles with the combined company. If, despite TECO Energy's retention and recruiting efforts, key employees retire, depart or fail to accept employment with TECO Energy or its subsidiaries due to the uncertainty of employment and difficulty of integration or a desire not to remain with the combined company, TECO Energy may incur significant costs in identifying, hiring, and retaining replacements for departing employees, which could have a material adverse effect on TECO Energy's business operations and financial results.

Matters relating to integration-related issues may place a significant burden on management, employees and internal resources, which could otherwise have been devoted to other business opportunities. The diversion of management time on integration -related issues could affect TECO Energy's financial results.

**We have been and may continue to be the target of securities class action suits and derivative suits which could result in substantial costs and divert management attention and resources**.

Securities class action suits and derivative suits are often brought against companies who have entered into mergers and acquisition transactions. Following the announcement of the execution of the Merger Agreement, 12 putative stockholder class actions were filed challenging the Merger. In November 2015, the defendants party to the litigation entered into a Memorandum of Understanding (the "MOU") with the various shareholder plaintiffs to settle, subject to court approval, all of the pending shareholder lawsuits challenging the proposed Merger. As a result of the MOU, TECO Energy made additional disclosures related to the proposed Merger in a proxy supplement filed on Nov. 18, 2015. Subsequent to the Merger closing the parties are expected to enter into a formal settlement agreement in August, which will be filed with the Hillsborough Circuit Court Judge for approval. Additionally, the judge will consider the award of attorneys' fees to the plaintiffs' lawyers. See **Note 12** to the **TECO Energy Consolidated Financial Statements**. Defending against these claims, even if meritless, can result in substantial costs to us and could divert the attention of our management.

**General Risks**

**National and local economic conditions can have a significant impact on the results of operations, net income and cash flows at TECO Energy and its subsidiaries.**

The business of TECO Energy is concentrated in Florida and New Mexico. While economic conditions in Florida and New Mexico have improved since the worst of the economic downturn in 2008, if they do not continue to improve or if they should worsen, retail customer growth rates may stagnate or decline, and customers' energy usage may further decline, adversely affecting TECO Energy's results of operations, net income and cash flows.

A factor in our customer growth in both Florida and New Mexico is net in migration of new residents, both domestic and non-U.S. A slowdown in the U.S. economy could reduce the number of new residents and slow customer growth. In addition, New Mexico has significant oil and natural gas production from the San Juan and Permian production basins. The current low oil and natural gas-price environment has reduced drilling activity and oil and natural gas production in some producing regions, which has reduced employment in those industries and industries that serve them. A continuation of these conditions could slow growth in the New Mexico economy, which could reduce earnings and cash flow from NMGC.

**Developments in technology could reduce demand for electricity and gas.**

Research and development activities are ongoing for new technologies that produce power or reduce power consumption. These technologies include renewable energy, customer-oriented generation, energy storage, energy efficiency and more energy-efficient appliances and equipment. Advances in these or other technologies could reduce the cost of producing electricity or transporting gas, or otherwise make the existing generating facilities of Tampa Electric uneconomic. In addition, advances in such technologies could reduce demand for electricity or natural gas, which could negatively impact the results of operations, net income and cash flows of TECO Energy.

**Results at TECO Energy's utilities may be affected by changes in customer energy-usage patterns.**

For the past several years, at Tampa Electric and electric utilities across the United States, weather-normalized electricity consumption per residential customer has declined due to the combined effects of voluntary conservation efforts, economic conditions and improvements in lighting and appliance efficiency.

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

**TECO Energy's businesses are sensitive to variations in weather and the effects of extreme weather, and have seasonal variations.**

TECO Energy's utility businesses are affected by variations in general weather conditions and unusually severe weather. Energy sales by its electric and gas utilities 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 and NMGC, which typically have short but significant winter peak periods that are dependent on cold weather, and are more weather-sensitive than Tampa Electric, which has both summer and winter peak periods. NMGC typically earns all of its net income in the first and fourth quarters, due to winter weather. Mild winter weather could negatively impact results at TECO Energy.

**TECO Energy's electric and gas utilities are highly regulated; changes in regulation or the regulatory environment could reduce revenues or increase costs or competition.**

TECO Energy's electric and gas utilities operate in highly regulated industries. Their retail operations, including the prices charged, are regulated by the FPSC in Florida and the NMPRC in New Mexico, 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 TECO Energy's utilities' 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, indicating an overearnings trend, those earnings could be subject to review by the FPSC. Ultimately, prolonged overearnings could result in credits or refunds to customers, which could reduce earnings and cash flow.

**Increased customer use of distributed generation could adversely affect TECO Energy's regulated electric utility business.**

In many areas of the United States, 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. Additionally, the EPA's Clean Power Plan could have the effect of providing greater incentives for distributed generation in order to meet state-based emission reduction targets under the proposed rule.

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 that is not supported by increased energy sales causes rates to increase for customers, which could further reduce energy sales and reduce profitability.

**Potential amendments to the Florida Constitution regarding solar energy could adversely impact Tampa Electric.**

In 2015, there was a proposed constitutional ballot initiative for the 2016 election approved by the Florida Supreme Court to promote increased direct sale and use of solar energy to generate electricity which has now been delayed to the 2018 election. There is also a proposed constitutional amendment on the August 2016 primary election ballot that could, if passed by 60% of the voters, lead to lower property taxes on solar technology used in commercial applications, and promote increased direct sale and use of solar energy to generate electricity.

The potential amendment to the Florida constitution in 2018 and the proposed amendment on the August 2016 primary election ballot would encourage the installation of solar arrays to generate electricity by retail customers and third parties, and allow sales of electricity by non-utility generators. Increased use of solar generation and sales by third parties would reduce energy sales and revenues at Tampa Electric. In addition, Tampa Electric could make investments in facilities to serve customers during periods that solar energy is not available that would not be profitable.

**Changes in the environmental laws and regulations affecting its businesses could increase TECO Energy's costs or curtail its activities.**

TECO Energy's 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 TECO Energy, requiring cost-recovery proceedings and/or requiring it to curtail some of its businesses' activities.

**Regulations on the disposal and/or storage of CCRs could add to Tampa Electric's operating costs.**

The U.S. EPA published a new CCR rule in the U.S. Federal Register on April 17, 2015, setting federal standards for companies that dispose of CCRs in onsite landfills and impoundments. The rule went into effect on Oct. 19, 2015, and contains design and operating standards for CCR management units. Tampa Electric is currently evaluating various options for demonstrating compliance with the rule. Activities in 2016 will consist primarily of monitoring and testing of the two existing CCR impoundments that are affected by this rule. Potential capital expenditures that may be required to comply with this rule are not expected to be significant. This rule is likely to face continued legal challenges by the utility industry and environmental groups, and legislation is required to fix certain portions of the rule. At this time, the ultimate outcome of any litigation or legislation is uncertain, so that it is not possible to predict the ultimate impact on Tampa Electric. While certain costs related to environmental compliance are currently recoverable from customers under Florida's ECRC, TECO Energy cannot be assured that any increased costs associated with the new regulations will be eligible for such treatment.

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

Among TECO Energy's companies, Tampa Electric has the most significant number of stationary sources with air emissions.

Current regulation in Florida allows utility companies to recover from customers prudently incurred costs for compliance with new state or federal 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 TECO Energy cannot be assured that the FPSC would grant such recovery. Under the Clean Power Plan, each state is responsible for implementing its own regulations to accord to the federal standards. Accordingly, a change in Florida's regulatory landscape could significantly increase Tampa Electric's costs. Changes in compliance requirements or the interpretation by governmental authorities of existing requirements may impose additional costs on TECO Energy requiring FPSC cost recovery proceedings and/or requiring it to curtail some of its business activities.

The Clean Power Plan establishes state-specific emission rate- and mass-based goals measured against a 2012 baseline. As Tampa Electric's investments in lower-GHG production largely occurred before 2012 and are factored into Florida's baseline generating capacity, Tampa Electric may encounter more difficulty than its competitors in achieving cost-effective GHG emission reductions. Because the ultimate form of Florida's state plan remains unknown, the increased compliance costs that Tampa Electric may face as a result of the Clean Power Plan are currently uncertain.

On Feb. 9, 2016, the U.S. Supreme Court issued a stay against enforcement of the Clean Power Plan for the electricity sector pending resolution of the legal challenges before the U.S. Court of Appeals for the District of Columbia Circuit. The timing of the resolution of the legal challenges and the removal of the stay by the U.S. Supreme Court is uncertain, but it is likely to delay further actions by the states until 2018.

**NMGC operates high-pressure natural gas transmission pipelines, which involve risks that may result in accidents or otherwise affect its operations.**

There are a variety of hazards and operating risks inherent in operating high-pressure natural gas transmission pipelines, such as leaks, explosions, mechanical problems, activities of third parties and damage to pipelines, facilities and equipment caused by floods, fires and other natural disasters that may cause substantial financial losses. In addition, these risks could result in significant injury, loss of life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, known as High Consequence Areas, the level of damage resulting from these risks could be greater. NMGC does not maintain insurance coverage against all of these risks and losses, and any insurance coverage it might maintain may not fully cover damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on TECO Energy's business, earnings, financial condition and cash flows.

**NMGC's high-pressure transmission pipeline operations are subject to pipeline safety laws and regulations, compliance with which may require significant capital expenditures, increase TECO Energy's cost of operations and affect or limit its business plans.**

TECO Energy's pipeline operations are subject to pipeline safety regulation administered by the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the U.S. Department of Transportation. These laws and regulations require TECO Energy to comply with a significant set of requirements for the design, construction, maintenance and operation of its pipelines. These regulations, among other things, include requirements to monitor and maintain the integrity of its pipelines. The regulations determine the pressures at which its pipelines can operate.

PHMSA is designing an Integrity Verification Process intended to create standards to verify maximum allowable operating pressure, and to improve and expand pipeline integrity management processes. There remains uncertainty as to how these standards will be implemented, but it is expected that the changes will impose additional costs on new pipeline projects as well as on existing operations. Pipeline failures or failures to comply with applicable regulations could result in reduction of allowable operating pressures as authorized by PHMSA, which would reduce available capacity on TECO Energy's pipelines. Should any of these risks materialize, it may have a material adverse effect on TECO Energy's operations, earnings, financial condition and cash flows.

**TECO Energy's computer systems and the infrastructure of its utility companies are 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, or otherwise adversely affect its business and financial results and condition.**

There have been an increasing number of cyberattacks 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, attachments to e-mails, through persons inside of the organization or through persons with access to systems inside of the organization.

TECO Energy has 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, TECO Energy cannot be assured that a cyberattack will not cause electric or gas system operational problems, disruptions of service to customers, compromise important data or systems, or subject it to additional regulation, litigation or damage to its reputation.

There have also been physical attacks on critical infrastructure at other utilities. While the transmission and distribution system infrastructure of TECO Energy's utility companies are designed and operated in a manner intended 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 TECO Energy's facilities or the industry in general, could also cause TECO Energy to incur additional security- and insurance-related costs, and could have adverse effects on its business and financial results and condition.

**Potential competitive changes may adversely affect TECO Energy's regulated electric and gas businesses.**

There is competition in wholesale power sales across the United States. 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 a number of years. Gas services provided by TECO Energy's gas utilities are unbundled for all non-residential customers. Because its gas utilities earn margins on distribution of gas but not on the commodity itself, unbundling has not negatively impacted TECO Energy's results. However, future structural changes could adversely affect PGS and NMGC.

**The value of TECO Energy's 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 TECO Energy's existing deferred tax asset and could result in a charge to earnings from the write-down of that asset, and it would reduce future tax payments received by TECO Energy from its subsidiaries.

**TECO Energy relies on some natural gas transmission assets that it does not own or control to deliver natural gas. If transmission is disrupted, or if capacity is inadequate, TECO Energy's ability to sell and deliver natural gas and supply natural gas to its customers and its electric generating stations may be hindered.**

TECO Energy depends on transmission facilities owned and operated by other utilities and energy companies to deliver the natural gas it sells to the wholesale and retail markets, as well as the natural gas it purchases for use in its electric generation facilities. If transmission is disrupted, or if capacity is inadequate, its ability to sell and deliver products and satisfy its contractual and service obligations could be adversely affected.

**Disruption of fuel supply could have an adverse impact on the financial condition of TECO Energy.**

Tampa Electric, PGS and NMGC depend on third parties to supply fuel, including natural gas and coal. As a result, there are risks of supply interruptions and fuel-price volatility. Disruption of fuel supplies or transportation services for fuel, whether because of weather-related problems, strikes, lock-outs, break-downs of locks and dams, pipeline failures or other events, could impair the ability to deliver electricity or gas or generate electricity and could adversely affect operations. Further, the loss of coal suppliers or the inability to renew existing coal and natural gas contracts at favorable terms could significantly affect the ability to serve customers and have an adverse impact on the financial condition and results of operations of TECO Energy.

**Commodity price changes may affect the operating costs and competitive positions of TECO Energy's businesses.**

TECO Energy's businesses are sensitive to changes in coal, gas, oil and other commodity prices. Any changes in the availability of these commodities could affect the prices charged by suppliers as well as suppliers' operating costs and the competitive positions 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 of, 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 and NMGC, 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 positions of PGS and NMGC as compared to electricity, other forms of energy and other gas suppliers.

**The facilities and operations of TECO Energy could be affected by natural disasters or other catastrophic events.**

TECO Energy's facilities and operations are exposed to potential damage and partial or complete loss resulting from environmental disasters (e.g. floods, high winds, fires and earthquakes), equipment failures, vandalism, potentially catastrophic events such as the occurrence of a major accident or incident at one of the sites, and other events beyond the control of TECO Energy. The operation of transmission and distribution systems involves certain risks, including gas leaks, fires, explosions, pipeline ruptures and other hazards and risks that may cause unforeseen interruptions, personal injury or property damage. Any such incident could have an adverse effect on TECO Energy and any costs relating to such events may not be recoverable through insurance or recovered in rates. In certain cases, there is potential that such an event may not excuse TECO Energy's utility companies from servicing customers as required by their respective tariffs.

**The franchise rights held by TECO Energy's utilities could be lost in the event of a breach by such TECO Energy utilities or could expire and not be renewed.**

TECO Energy's utilities hold franchise rights that are memorialized in agreements with selected counterparties throughout their service areas. In some cases these rights could be lost in the event of a breach of these agreements by the applicable TECO Energy utility. In addition, these agreements are for set periods and could expire and not be renewed upon expiration of the then-current terms. Some agreements also contain provisions allowing municipalities to purchase the portion of the applicable utility's system located within a given municipality's boundaries under certain conditions.

**Tampa Electric, PGS and NMGC may not be able to secure adequate rights of way to construct transmission lines, gas interconnection lines and distribution-related facilities and could be required to find alternate ways to provide adequate sources of energy and maintain reliable service for their customers.**

Tampa Electric, PGS and NMGC rely on federal, state and local governmental agencies and, in New Mexico, cooperation with local Native American tribes and councils, to secure rights of way and siting permits to construct transmission lines, gas interconnection lines and distribution-related facilities. If adequate rights of way and siting permits to build new transportation and transmission lines cannot be secured:

- Tampa Electric, PGS and NMGC may need to remove or abandon its facilities on the property covered by rights of way or franchises and seek alternative locations for its transmission or distribution facilities;
- Tampa Electric, PGS and NMGC may need to rely on more costly alternatives to provide energy to their customers;
- Tampa Electric, PGS and NMGC may not be able to maintain reliability in their service areas; and/or
- Tampa Electric's, PGS's and NMGC's ability to provide electric or gas service to new customers may be negatively impacted.

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

TECO Energy assesses 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, TECO Energy may be required to record non-cash impairment charges that could have a material adverse impact on TECO Energy's financial condition and results from operations. In connection with the NMGC acquisition, TECO Energy recorded additional goodwill and long-lived assets that could become impaired.

**TECO Energy has substantial indebtedness, which could adversely affect its financial condition and financial flexibility.**

TECO Energy has substantial indebtedness, which has resulted in fixed charges it is obligated to pay. The level of TECO Energy's indebtedness and restrictive covenants contained in its debt obligations could limit its ability to obtain additional financing (see **Management's Discussion & Analysis – Significant Financial Covenants** section).

TECO Energy, TECO Finance, TEC, NMGC and NMGI must meet certain financial covenants as defined in the applicable agreements to borrow under their respective credit facilities. Also, TECO Energy and its subsidiaries have certain restrictive covenants in specific agreements and debt instruments.

Although TECO Energy was in compliance with all required financial covenants as of June 30, 2016, it cannot assure compliance with these financial covenants in the future. TECO Energy's failure to comply with any of these covenants or to meet its 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. TECO Energy may not have sufficient working capital or liquidity to satisfy its debt obligations in the event of an acceleration of all or a portion of its outstanding obligations. If TECO Energy's cash flows and capital resources are insufficient to fund its debt service obligations, it may be forced to reduce or delay investments and capital expenditures, or to sell assets, seek additional capital or restructure or refinance its indebtedness. TECO Energy's ability to restructure or refinance its debt will depend on the condition of the capital markets and TECO Energy's financial condition at such time. Any refinancing of TECO Energy's debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments may restrict TECO Energy from adopting some of these alternatives.

TECO Energy also incurs obligations in connection with the operations of its subsidiaries and affiliates that do not appear on its balance sheet. Such obligations include guarantees, letters of credit and certain other types of contractual commitments.

**Financial market conditions could limit TECO Energy's access to capital and increase TECO Energy's costs of borrowing or refinancing, or have other adverse effects on its results.**

TECO Finance and TEC have debt maturing in 2017 and subsequent years, which may need to be refinanced. Future financial market conditions could limit TECO Energy's ability to raise the capital it needs and could increase its interest costs, which could reduce earnings. If TECO Energy is not able to issue new debt, or TECO Energy issues debt at interest rates higher than expected, its financial results or condition could be adversely affected.

**TECO Energy enters 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.**

TECO Energy enters into derivative transactions with counterparties, most of which are financial institutions, to hedge its exposure to commodity price and interest rate changes. Although TECO Energy believes it has 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 TECO Energy has an in-the-money position, TECO Energy could be unable to collect from such counterparty.

**Declines in the financial markets or in interest rates used to determine benefit obligations could increase TECO Energy's pension expense or the required cash contributions to maintain required levels of funding for its plan.**

Under calculation requirements of the Pension Protection Act, as of the Jan. 1, 2016, measurement date, TECO Energy's pension plan was essentially fully funded. Under MAP 21, TECO Energy is not required to make additional cash contributions over the next five years; however, TECO Energy may make additional cash contributions from time to time. Any future declines in the financial markets or further declines in interest rates could increase the amount of contributions required to fund its pension plan in the future, and could cause pension expense to increase.

**TECO Energy's financial condition and results could be adversely affected if its capital expenditures are greater than forecast.**

In 2016, TECO Energy is 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. In 2016, TECO Energy is forecasting capital expenditures at PGS to support customer growth, system reliability, conversion of customers from other fuels to natural gas and to replace bare steel and cast iron pipe. Forecasted capital expenditures at NMGC are expected to support customer and system reliability and expansion.

If TECO Energy's capital expenditures exceed the forecasted levels, it may need to draw on credit facilities or access the capital markets on unfavorable terms. TECO Energy cannot be sure that it will be able to obtain additional financing, in which case its financial position could be adversely affected.

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

TECO Energy's senior unsecured debt is rated as investment grade by S&P at 'BBB', by Moody's at 'Baa2', and by Fitch at 'BBB'. The senior unsecured debt of TEC is rated by S&P at 'BBB+', by Moody's at 'A3' and by Fitch at 'A-'. The senior unsecured debt of NMGC is rated by S&P at BBB+. A downgrade to below investment grade by the rating agencies, which would require a two-notch downgrade by S&P, Moody's and Fitch, may affect TECO Energy's ability to borrow, may change requirements for future collateral or margin postings, and may increase financing costs, which may decrease earnings. TECO Energy may also experience greater interest expense than it would have otherwise if, in future periods, it replaces maturing debt with new debt bearing higher interest rates due to any downgrades. In addition, downgrades could adversely affect TECO Energy's relationships with customers and counterparties.

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

**TECO Energy is a holding company with no business operations of its own and depends on cash flow from its subsidiaries to meet its obligations.**

TECO Energy is a holding company with no business operations of its own or material assets other than the stock of its subsidiaries. Accordingly, all of TECO Energy's operations are conducted by its subsidiaries. As a holding company, TECO Energy requires dividends and other payments from its subsidiaries to meet its cash requirements. If TECO Energy's subsidiaries are unable to pay it dividends or make other cash payments to it, TECO Energy may be unable to satisfy its obligations.

**In connection with the sale of TECO Coal to Cambrian, TECO Energy temporarily retained obligations under letters of indemnity that guarantee payments on bonds posted for the reclamation of mines prior to the completion of the transfer of all permits to the purchaser by the Commonwealths of Kentucky and Virginia.**

These letters of indemnity guarantee payments to certain surety companies that issued reclamation bonds to the Commonwealths of Kentucky and Virginia in connection with TECO Coal's mining operations. Payments by TECO Energy to the surety companies would be triggered if the reclamation bonds are called upon by either of these states and the permit holder or TECO Coal or one of the affiliates transferred to Cambrian as part of the sale did not pay the surety company. Pursuant to the SPA, Cambrian is obligated to file applications required in connection with the change of ownership and control of TECO Coal and its affiliates with the appropriate governmental entities with respect to the coal mining permits. Pursuant to the terms of the SPA, Cambrian is obligated to post a bond or other appropriate collateral necessary to obtain the release of the corresponding bond(s) secured by the TECO Energy indemnity for that permit. The company is working with Cambrian on the process of replacing the bonds. However, until the bonds secured by TECO Energy's indemnity are released, TECO Energy's indemnity will remain effective.

**Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS**

The following table shows the number of shares of TECO Energy common stock deemed to have been repurchased by TECO Energy:

| | 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 |
|---|---|---|---|---|
| Apr. 1, 2016 - Apr. 30, 2016 | 348 | $ 27.75 | 0 | 0 |
| May 1, 2016 - May 31, 2016 | 4,109 | $ 27.55 | 0 | 0 |
| June 1, 2016 - June 30, 2016 | 323 | $ 27.70 | 0 | 0 |
| Total 2nd Quarter 2016 | 4,780 | $ 27.57 | 0 | 0 |

(1) These shares were not repurchased through a publicly announced plan or program, but rather relate to retirement plans of the company. Specifically, these shares represent shares purchased by the TECO Energy Group Retirement Savings Plan pursuant to directions from plan participants or dividend reinvestment.

**Item 6. EXHIBITS**

**Exhibits** - See index on page 66.

**SIGNATURES**

Pursuant to the requirements 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.
(Registrant)

Date: August 8, 2016

By: /s/ S. W. CALLAHAN
S. W. CALLAHAN
Senior Vice President-Finance and Accounting and
Chief Financial Officer (Chief Accounting Officer)
(Principal Financial and Accounting Officer)

TAMPA ELECTRIC COMPANY
(Registrant)

Date: August 8, 2016

By: /s/ S. W. CALLAHAN
S. W. CALLAHAN
Vice President-Finance and Accounting and
Chief Financial Officer (Chief Accounting Officer)
(Principal Financial and Accounting Officer)

## INDEX TO EXHIBITS

| Exhibit No. | Description | |
|---|---|---|
| 3.1 | Amended and Restated Articles of Incorporation of TECO Energy, Inc., as filed on July 1, 2016 (Exhibit 3.1, Form 8-K dated July 1, 2016 of TECO Energy, Inc.). | * |
| 3.2 | Bylaws of TECO Energy, Inc., as amended and restated effective July 1, 2016 (Exhibit 3.2, Form 8-K dated July 1, 2016 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 2010 of TECO Energy, Inc. and Tampa Electric Company). | * |
| 4.1 | Twelfth Supplemental Indenture dated as of July 1, 2016 between TECO Energy, Inc. and The Bank of New York Mellon, as trustee. | |
| 4.2 | Fifth Supplemental Indenture dated as of July 1, 2016 between TECO Finance, Inc., TECO Energy, Inc. and The Bank of New York Mellon Trust Company, N.A., as trustee. | |
| 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 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. | |
| 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) | |
| 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 Quarterly Report on Form 10-Q 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 TEC were filed under Commission File Nos. 1-8180 and 1-5007, respectively.

# Exhibit B

**TAMPA ELECTRIC DIVISION**
**PROJECTED STATEMENT OF SOURCES AND USES OF FUNDS**
**FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2017**
**(MILLIONS)**

| | |
|---|---|
| Cash Flows from Operating Activities: | |
| Depreciation | $ 305 |
| Deferred Income Taxes | 158 |
| Other | (16) |
| | 447 |
| Cash Flows from Investing Activities: | |
| Capital Expenditures, excluding AFUDC | (318) |
| Cash Flows from Financing Activities: | |
| Changes in Financing | (129) |
| Total Cash Flows, excluding Net Income | $ 0 |

**TAMPA ELECTRIC DIVISION**
**PROJECTED CONSTRUCTION BUDGET**
**FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2017**
**(MILLIONS)**

| | |
|---|---|
| New Generation, including Transmission | $ 15 |
| Existing Generation | 92 |
| Transmission & Distribution | 187 |
| Other | 24 |
| Total Projected Construction Budget, excluding AFUDC | $ 318 |

**PEOPLES GAS SYSTEM DIVISION**
**PROJECTED STATEMENT OF SOURCES AND USES OF FUNDS**
**FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2017**
**(MILLIONS)**

| | |
|---|---|
| Cash Flows from Operating Activities: | |
| Depreciation | $ 61 |
| Other | (7) |
| | 54 |
| Cash Flows from Investing Activities: | |
| Capital Expenditures, excluding AFUDC | (130) |
| Cash Flows from Financing Activities: | |
| Changes in Financing | 76 |
| Total Cash Flows, excluding Net Income | $ 0 |

**PEOPLES GAS SYSTEM DIVISION**
**PROJECTED CONSTRUCTION BUDGET**
**FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2017**
**(MILLIONS)**

| | |
|---|---|
| Revenue Producing | $ 90 |
| Maintenance | 28 |
| Cast Iron / Bare Steel Replacement | 12 |
| Total Projected Construction Budget, excluding AFUDC | $ 130 |